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CLEAN COAL, OIL AND GAS DEVELOPMENT, NEW ENERGY OPPORTUNITIES THROUGH CARBON CAPTURE AND STORAGE

HEARING

BEFORE A

SUBCOMMITTEE OF THE

COMMITTEE ON APPROPRIATIONS

UNITED STATES SENATE

ONE HUNDRED TENTH CONGRESS

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CLEAN COAL, OIL AND GAS DEVELOPMENT, NEW ENERGY OPPORTUNITIES THROUGH CARBON CAPTURE AND STORAGE

MONDAY, AUGUST 13, 2007

U.S. SENATE,
SUBCOMMITTEE ON ENERGY AND WATER DEVELOPMENT,
COMMITTEE ON APPROPRIATIONS,
Bismarck, ND.

The subcommittee met at 9:38 a.m., in the Pioneer Room, State Capitol Building, Hon. Byron L. Dorgan (chairman) presiding.

Present: Senator Dorgan.

OPENING STATEMENT OF SENATOR BYRON L. DORGAN

Senator DORGAN. I call the hearing to order. This is a hearing of the Senate Energy and Water Development Appropriations Subcommittee. The hearing subject is clean coal, oil and gas development and new energy opportunities through carbon capture and storage.

I'm Byron Dorgan, chairman of this Appropriations subcommittee. The ranking member is Senator Domenici from New Mexico, who is not able to be with us today, but I'm pleased that Franz Wuerfmannsdobler is here. Franz is a principal staffer on our Energy and Water Subcommittee dealing principally with energy issues.

I want to thank all of you for coming. This is a very interesting subject, and I want to make just a couple of comments as we begin and then I will call on a number of witnesses.

We're talking a lot about energy independence these days because we are, in my judgment, dangerously dependent on foreign sources of oil. Sixty percent of our oil comes from outside of our country, much from troubled parts of the world. If, God forbid, something should interrupt the oil pipeline tomorrow morning from Saudi Arabia, Venezuela, Iraq, or you name it, our economy, our country, would be in very serious trouble. And because we are dangerously dependent on foreign sources of oil, we're talking about how we become less dependent and, therefore, identify the domestic resources we can use to become less dependent.

We have abundant resources of fossil fuels, coal, oil, and natural gas. We have substantial opportunities in renewable fuels and we're going to do much more in all of these areas. There's a lot of talk about renewable fuels, and we know that we're doing a lot on wind energy in North Dakota, which I've supported for a long while. We're seeing ethanol plants being developed and biomass as well; we're seeing a lot of new things happening in the renewable fuels area.

But this should not suggest that we are not going to use our fossil fuels. We are. I don't think anyone believes that somehow in a short, intermediate or long term that we're not going to continue to use fossil fuels. The question isn't "whether." The question is under what conditions we use them.

And I say that because these days things have changed with respect to those calculations. Now you can't discuss these issues without discussing climate change in the same breath. We've come to an intersection where the issue of climate change relating to energy production and the use of energy is a significant part of many future policy discussions, and so we'll be talking about that today.

We're now seeing some of the highest prices for oil and gasoline that we've seen in the history of this country. We know that 80 to 90 percent of the proven oil reserves on this Earth of ours are controlled by entities owned by foreign governments—let me say that again, 80 to 90 percent of the known and proven reserves are owned by entities or controlled by entities that are owned by foreign governments. That's an important thing to understand in terms of the geopolitics of our planet.

We stick little straws in our planet and we suck oil out of this planet that we live on. We suck out about 84 million barrels a day, and we use one-fourth of that here in the United States of America, about 21 million barrels a day. So we take out about 84 million barrels every day out of this planet. We have a prodigious appetite for it here in the United States of America. Saudi Arabia has what we think to be the world's largest reserves of oil, 265 billion barrels, but it is not clear that that's a good number. It's just the best number people have. And as I said, 265 billion barrels—not million, billion barrels.

In the history of oil production in our country, since we started producing oil and discovered oil, we've produced about 195 billion barrels of oil in the United States, and reports indicate that there are about 20 billion barrels that are estimated reserves in this country at the moment. We also hear that, even though those are the reserves that are estimated, there are about 200 billion barrels more that remain residually in geographically complicated, partially produced or perhaps even mature oilfields that are potentially achievable; that is, it exists, but is residual oil that is not pulled up under normal oil drilling circumstances. Why is that important? Why have I described that? Because we're also going to use coal in the future.

I have been working on this subcommittee to invest in research for coal development. I have increased substantially the President's request for that research. The President has talked a lot about research, but had not quite the appetite to ask for the funding for it, so Senator Domenici and I substantially increased funding because we know this Nation is going to use fossil fuels. The question is how. And research to unlock the opportunities, for example, to have coal-fired generating plants that are zero-emission plants is research that, I believe, is very important to the future of this country.

But we also know that in the process of developing various types of energy, particularly in the area of coal-based energy, there are greenhouse gases that are emitted, CO_2 primarily, and we know that there is a climate change issue that our country and the world is now concerned about. We also understand that with the largest reserves of coal, somewhere in the neighborhood of 200 years, perhaps much, much more than that, worth of coal at the current usage rates, we must continue to unlock the ability to use that coal without injuring our climate.

And one of the ways to do that, I believe, that we've been discussing in our committee and funding research of, is to capture the carbon in coal-fired plants and sequester it in oil wells, which may enhance oil recovery. And when oil is $60, $70, $75 a barrel, the ability to use a product that you need to capture and contain anyway for beneficial use in an oilfield gives you the opportunity to help pay for the cost of capture. We could enhance substantial oil recovery and protect the environment, even as we continue to substantially use the coal resource that's in such abundant supply.

These issues kind of relate and we're trying to determine through research what we can do, how we can do it, what is commercially capable now, what we think might be commercially capable with the use of new research and technology later. I won't quote former Secretary of Defense Rumsfeld about what we don't know, what we don't know what we don't know, and he went on and on at length, but there's a lot we don't know. Some we do know. And as we follow the trail, follow the clues that lead us to believe that, through technology and research, we can continue in a very significant way to use our most abundant resource—fossil fuels—innovatively, by using the product of carbon that is produced in a beneficial rather than detrimental way, that could prove dramatic for this country's energy future.

I want our State to be a leader in this area. We have greater capability than, I believe, any other State in this country. We have abundant coal and we have substantial oil. I should mention to all of you that the U.S. Geological Survey has indicated to me that in early 2008 the Dr. Price study will be redone and we will know then what our Bakken shale potential is. If it is anywhere near what someone suggested it was we are on the threshold of substantial opportunities in oil development. And, in addition to that, we have opportunities in virtually every other form of energy production. Very few States—perhaps no State—has a greater capability than we do, and that's why I'm excited about this. Producing energy for a hungry country and world is a very important thing to do. Energy production would enhance our economy, but also, if we do it the right way, contribute substantially to the well-being of our country.

So we have a number of people here today. I want to just say, as I introduce those who will be testifying that there's a lot of good work going on in North Dakota. We've got interesting things happening already, and have for some long while. We have the only coal gasification plant in the country—synthetic coal gasification plant. We've learned a lot from that and are still learning from it. We've got a lot of other inventive and interesting endeavors here; for instance what I think, is the world's largest CO_2 capture project that pipes in to Canada for enhanced oil recovery. That's the Basin Electric project. So there's a lot going on. We've got a lot of other people that are engaged in new, interesting projects that can significantly enhance our energy future as well.

So I thank all of you for coming and being a part of this. I want to introduce the first witness, Carl Bauer, the Director of the National Energy Technology Laboratory. Carl is someone who has a substantial relationship with the Senate Energy Committee in the sense that we call on him a lot for testimony and rely a lot on substantial cutting-edge research being done by him and the people who work at his national laboratory.

Carl, welcome to North Dakota. Thank you very much and you may proceed.

STATEMENT OF CARL O. BAUER, DIRECTOR, NATIONAL ENERGY TECHNOLOGY LABORATORY, DEPARTMENT OF ENERGY

Mr. BAUER. Thank you, Chairman Dorgan. I appreciate the opportunity to provide testimony on DOE's advanced clean coal technologies and the program for carbon capture and storage.

The economic prosperity of the United States over the past century has been built upon an abundance of fossil fuels. Making full use of this domestic asset in a responsible manner will enable the country to fulfill its energy requirements and its obligation to its people in the century ahead.

Given current technologies, coal prices, and the rate of consumption, the United States has approximately a 250-year supply of coal available.

The Nation is also the home to a large resource of oil. We have currently proven reserves—and I'm kind of rehashing what you've already said, Senator, but I'll just go on with it—22 billion barrels. A recent study by Advanced Resources International for DOE identified 390 billion barrels of oil remaining in place after current production methods. The instrument that more than 40 billion barrels could be made economic if ready supply of low-cost CO_2 was available and improved, technology for enhanced oil recovery was applied. There is a growing consensus that increased level of greenhouse gas emissions are linked to climate change, and fossil fuel use has been identified as a major source of these emissions, particularly of CO_2.

Slowing the growth of these emissions has become an important concern and both of these challenges, developing domestic sources of fossil fuels and reducing the emissions of CO_2 from coal-fired power plants, can be addressed through the use of captured CO_2 for enhanced oil recovery. While not the complete solution to either of these challenges, incremental oil produced from such applications could help offset the initial cost of CO_2 capture and storage. The prospect of low-cost supplies of captured CO_2 could provide the impetus for a national reevaluation of the EOR potential in many of the mature fields. Continued evolution of enhanced oil recovery and advances in developing and deploying CO_2 captured from coal power could help realize this synergy between the coal and power industry and the oil industry.

Though the challenges are significant, the United States is well positioned to capitalize on these synergies. Past DOE-funded research helped advance industrial enhanced oil recovery operations. Today the focus is on the carbon captured storage side problem. To date, for 35 years of enhanced oil recovery, only 1 billion barrels have been produced through the use of CO_2 EOR, so there's a great opportunity for a lot more oil to come forward.

The Office of Fossil Energy's coal R&D program provides for the development of new environmentally responsible, cost-effective approaches to coal use. It includes technologies that will either facilitate the efficient capture of CO_2 from the coal-fired plants for subsequent sequestration or directly address the solutions for safe and permanently sequestering it in the underground reservoirs. Details of these programs are in my written testimony.

With the core coal R&D program, the Carbon Sequestration Regional Partnership, of which North Dakota is one of the leaders, have brought an enormous amount of capability and experience together to work on the challenges of both infrastructure development and stored underground carbon. The partnerships are conducting field tests to validate the efficacy of carbon capture and storage technologies in a variety of geological and terrestrial storage sites throughout the United States and Canada. We are working with North Dakota's Energy & Environmental Research Center on the Plains CO_2 Reduction Partnership, which is defining the potential of sequestration in North Dakota, South Dakota, and in Alberta, Canada. EERC is also addressing issues related to low-rank subbituminous and lignite coal utilization.

PREPARED STATEMENT

Developing the technologies needed to support a widespread expansion of CO_2 EOR could substantially increase existing U.S. reserves and production. The DOE's efforts are providing the elements needed to enable this expansion by advancing capture technologies to ensure a reliable low-cost supply of CO_2 and improved EOR technologies to optimize for carbon sequestration co-benefits.

Mr. Chairman, this completes my statement. I would be happy to take any questions you have.

[The statement follows:]

PREPARED STATEMENT OF CARL O. BAUER

Thank you Mr. Chairman. I appreciate this opportunity to provide testimony on the Department of Energy's advanced clean coal technologies and the program for carbon capture and storage.

The economic prosperity of the United States over the past century has been built upon an abundance of fossil fuels in North America. The United States' fossil fuel resources represent a tremendous national asset. Making full use of this domestic asset in a responsible manner enables the country to fulfill its energy requirements, minimize detrimental environmental impacts, and positively contribute to national security.

Given current technologies, coal prices, and rates of consumption, the United States has approximately a 250-year supply of coal available. Coal-fired power plants supply about half of our electricity and are expected to continue to do so through mid-century. Because electricity production increases at a rate of about 2 percent per year, the rate of coal use will increase proportionally. However, the continued use of this secure domestic resource will be dependent on the development of cost-effective technology options to meet both economic and environmental goals, including the reduction of greenhouse gas emissions.

The Nation is also home to a large resource of oil. Although much of the Nation's onshore petroleum resource has been produced, large volumes of crude oil remain in place after current production methods are exhausted. These resources are being held in place by physical forces or left behind due to geologic complexity being both economically and technologically challenged. The total volume of this stranded oil is estimated by Advanced Resources International (ARI) of Washington, DC, to exceed 390 billion barrels, of which roughly 200 billion barrels are estimated to be relatively accessible at depths of up to 5,000 feet but do not have CO_2 available for EOR. To put these numbers in context, according to the Energy Information Administration (EIA), we have produced about 195 billion barrels of our petroleum resource over the past 120 years and currently have proven reserves of roughly 22 billion barrels (source: EIA online database, as of December 2005, crude oil, does not include natural gas liquids).

Currently, there is growing consensus that increased levels of greenhouse gases in the atmosphere, primarily carbon dioxide, methane, nitrous oxide, and chlorofluorocarbons, are linked to climate change. In this connection, fossil fuel use, in general, and coal-fired power plants, in particular, have been identified as a major source of anthropogenic greenhouse gas emissions, particularly carbon dioxide, into the atmosphere. Slowing the growth of anthropogenic greenhouse gas emissions has become an important concern.

Both of these challenges—developing domestic sources of fossil fuels and reducing emissions of carbon dioxide (CO_2) from coal-fired power plants—can be addressed simultaneously through the use of captured CO_2 for enhanced oil recovery (EOR). While not the complete solution to either of these challenges, incremental oil produced from such applications could help offset the costs of CO_2 capture, while the prospect of low-cost supplies of captured CO_2 in widespread areas of the country could provide the impetus for a national re-evaluation of the EOR potential in many mature fields. While EOR is a mature technology that has been in commercial use for decades, CO_2 capture from coal power is not yet commercial. Continued evolution of EOR and transformational advances in development and deployment of CO_2 capture from coal power could help realize this synergy between the coal/power industry and the oil industry.

HOW IS DOE RESPONDING TO THESE ISSUES?

While the challenges are significant, the United States is well positioned to capitalize on these synergies. The oil industry has been using CO_2 for EOR in commercial applications for decades. As early as the 1970s, DOE-funded projects were assessing the fluid properties of CO_2 to establish its applicability in EOR. A special focus was given to developing correlations that helped the oil industry utilize these properties to optimize commercial EOR projects. During 1993–2003, DOE funded nearly half of the $100 million spent on the Class Program CO_2–EOR Field Demonstration Projects in six States. Approaches included the use of horizontal wells for improved reservoir contact, four-dimensional seismic to monitor the behavior of CO_2 floods, automated field-monitoring systems for detecting problems, and the injection of increasingly larger volumes of CO_2 to increase recovery rates. In summary, this DOE-funded research has helped advance industrial EOR operations, but the focus is now on the carbon sequestration side of EOR, which is a developing technology, rather than the oil production side of EOR, which is a mature technology. DOE-funded research continues to include some research on EOR.

The Office of Fossil Energy's core coal R&D program provides for the development of new cost- and environmentally-effective approaches to coal use. It includes technologies that will either facilitate the efficient capture of CO_2 from coal-fired plants for subsequent sequestration or directly address solutions for safely and permanently sequestering it in underground reservoirs. These programs include gasification, advanced turbines, fuel cells, FutureGen, and carbon sequestration, and are described in more detail below.

Gasification

Gasification is a pre-combustion pathway to convert coal or other carbon-containing feedstocks into synthesis gas, a mixture composed primarily of carbon monoxide and hydrogen; the synthesis gas, in turn, can be used as a fuel to generate electricity or steam, or as a basic raw material to produce hydrogen, high-value chemicals, and liquid transportation fuels. DOE is developing advanced gasification technologies to meet the most stringent environmental regulations in any State and facilitate the efficient capture of CO_2 for subsequent sequestration—a pathway to "near-zero atmospheric emissions" coal-based energy. Gasification plants are complex systems that rely on a large number of interconnected processes and technologies. Advances in the current state-of-the-art, as well as development of novel approaches, could help reveal the technical pathways enabling gasification to meet the demands of future markets while contributing to energy security.

Advanced Turbines

The Advanced Turbine Program consists of a portfolio of laboratory and field R&D projects focused on performance-improvement technologies with great potential for increasing efficiency and reducing emissions and costs in coal-based applications. The Program focuses on the combustion of pure hydrogen fuels in MW-scale turbines greater than 100 MW size range and the compression of large volumes of CO_2. Since advanced turbines will be fuel flexible, capable of operating on hydrogen or syngas, they will make possible electric power generation in gasification applications configured to capture CO_2.

Fuel Cells

Fuel cells could help support the efficiency and emission targets of future power plants, such as FutureGen. In order to ensure the ability to site future power plants in any State in the country, low emissions of criteria pollutants will be required. Fuel cell emissions are well below current and proposed environmental limits. Their modular nature permits use in central or distributed generation with equal ease. Rapid response to emergent energy needs is enhanced by the modularity and fuel flexibility of fuel cells. The ultimate goal of the program is the development of low-cost large (>100 MW) fuel cell power systems that will produce affordable, efficient, and environmentally friendly electrical power from coal with greater than 50 percent higher heating value (HHV) efficiency, including integrated coal gasification and carbon dioxide separation processes that capture at least 90 percent of the CO_2 emissions from the system. The cost goal for fuel cells in coal systems is to achieve a ten-fold reduction in the fuel cell system cost.

FutureGen

FutureGen is a $1 billion Government-industry initiative to design, build, and operate an advanced, coal-based, Integrated Gasification Combined-Cycle (IGCC) power plant to:

—Co-produce electricity and hydrogen;
—Achieve near-zero atmospheric emissions, with geological sequestration of carbon dioxide;
—Demonstrate system integration of cutting edge technologies; and
—Chart a technological pathway toward an energy future in which near-zero atmospheric emissions clean coal power plants can be designed, built, and operated at a cost that is no more than 10 percent above the cost of non-sequestered systems.

Coal continues to face environmental challenges relative to other energy sources. The near-zero atmospheric emissions concept spearheaded by FutureGen is vital to the future viability of coal as an energy resource, particularly in light of growing climate change concerns. Coal is abundant, secure, and relatively inexpensive when compared to other energy sources. With near-zero atmospheric emissions, coal could not only produce baseload electricity, but also help germinate a hydrogen energy economy.

Carbon Sequestration

The Carbon Sequestration Program consists of a portfolio of laboratory and field R&D focused on technologies with great potential for reducing greenhouse gas emissions. Most efforts focus on capturing carbon dioxide from large stationary sources such as power plants, and sequestering carbon dioxide in geologic formations. Carbon sequestration is a key component of the President's strategy to slow the growth of greenhouse gas emissions, as well as several National Energy Policy goals targeting the development of new technologies. It also supports the goals of the Framework Convention on Climate Change and other international collaborations to reduce greenhouse gas intensity and greenhouse gas emissions. The programmatic timeline is to demonstrate a portfolio of safe, cost-effective greenhouse gas capture, storage, and mitigation technologies at the pre-commercial scale by 2012, leading to demonstration and substantial deployment and market penetration beyond 2012. These greenhouse gas mitigation technologies could help slow greenhouse gas emissions in the medium term. They also provide potential for ultimately stabilizing and reducing greenhouse gas emissions in the United States.

OPPORTUNITIES FOR SYNERGY BETWEEN COAL AND OIL INDUSTRIES

Many EOR processes incorporating thermal, chemical, microbial, and a variety of miscible gas-injection methods have been employed in the United States. Among these, CO_2–EOR is most promising and has in fact produced 1 billion barrels of oil to date. Because CO_2 is miscible with crude oil under certain conditions, it can be injected into previously drained oil reservoirs and used to sweep a portion of the remaining oil from the rock, helping to overcome the physical forces that trap the residual oil. While not all of the easily accessible stranded oil is susceptible for recovery by CO_2–EOR, a large proportion could be recovered if a source of low-cost CO_2 and improved CO_2–EOR technologies are developed and applied to the problem.

A series of CO_2–EOR assessments conducted for DOE's Office of Fossil Energy by ARI concluded that, if current high oil prices are sustained over the long-term, low-cost captured CO_2 from power plants is available (at a cost of between $27 and $34 per ton of CO_2 delivered to the oil field), and improved CO_2–EOR technology is applied which maximizes oil recovery while minimizing the CO_2 needed, 47 billion barrels of incremental oil—more than twice the current U.S. reserve—would be economic to produce. Of course, only a few companies currently have access to the state of the art technology and oil companies take many factors into consideration when determining which investments to make. Therefore, even if these technological advances are made, it is possible that not all of the additional 47 billion barrels of domestic oil would be produced.

Within just the large fields in North Dakota's portion of the Williston Basin, as much as 390 million barrels of incremental oil could have a cost of production less than the current price of oil under this scenario. In addition, the feasibility of converting the large unconventional in-place resource within the Bakken Shale of North Dakota into economic reserves using next generation CO_2–EOR technology has not been examined (studies have suggested that 100 to 150 billion barrels, or more, of resource may be in-place). However, if injection of CO_2 into this fractured shale could mobilize a portion of this resource, the Williston Basin's contribution to the Nation's oil supply could be significantly expanded.

In addition, while the main focus of CO_2–EOR is on maximizing the amount of oil produced rather than the amount of CO_2 injected, its sequestration potential is still significant, though much less than the sequestration potential of saline formations in the U.S. Estimates by Vello Kuuuskraa at ARI are that the technical limit for CO_2 storage associated with EOR is 20 gigatons and that between 8–12 gigatons can be economically stored if next generation EOR technology is developed and applied, assuming that the cost of CO_2 is less than $30–$38/ton delivered, which would require significant advances in carbon capture technology. To put this into context, total man-made U.S. greenhouse gas emissions (carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons) in 2004 were the equivalent of about 7.8 gigatons of CO_2 equivalent. This total includes approximately 6 gigatons of actual CO_2. About 2.2 gigatons of this CO_2 comes from coal-fired power plants, and the balance (approximately 3.8 gigatons) stems from oil and gas use.

According to the Energy Information Administration's Annual Energy Outlook 2007, coal-fired generation produced 84 percent of the CO_2 associated with electrical power generation in 2006, and 33 percent of total U.S. emission of CO_2. This forecast also suggests that CO_2 from coal-fired power generation is expected to represent 88 percent of all CO_2 related to electric power generation by 2030, and 37 percent of total U.S. emission of CO_2.

CO_2–EOR projects represent an early major opportunity for helping to realize carbon capture technology. This opportunity has unique potential to overcome economic, social, and risk obstacles associated with the commercialization of technology. In addition, the use of CO_2–EOR projects could help power generation companies to take advantage of the oil industry's expertise with CO_2 handling and injection, and help accelerate the implementation of other underground CO_2 sequestration options in coalbeds, depleted gas reservoirs, and deep saline formations.

CONCLUSION

Today, nearly three out of every four coal-burning power plants in this country are equipped with technologies that can trace their roots back to the Clean Coal Technology Program. Approaches demonstrated through the program include coal processing to produce clean fuels, combustion modification to control emissions, post-combustion cleanup of flue gas, and repowering with advanced power generation systems. These efforts helped accelerate production of cost-effective compliance options to address environmental issues associated with coal use. Relative to carbon capture and storage, DOE is making significant progress in developing the technologies and infrastructure needed for deployment of these technologies in a future carbon-constrained world. Evidence of this progress includes:

—The Carbon Sequestration Atlas of the United States and Canada, developed by NETL, the Regional Carbon Sequestration Partnerships (Partnerships), and the National Carbon Sequestration Database and Geographical Information System, contains information on stationary sources for CO_2 emissions, geologic formations with sequestration potential, and terrestrial ecosystems with potential for enhanced carbon uptake, all referenced to their geographic location to enable matching sources and sequestration sites.

—Carbon dioxide capture technology is being developed for solvent, sorbent, membrane, and oxy-combustion systems that, if successfully developed, would be capable of capturing greater than 90 percent of the flue gas carbon dioxide at a significant cost reduction when compared to state-of-the-art, amine-based capture systems. Research and systems analysis have identified potential cost reductions of 30–45 percent for the capture of CO_2. In addition, ionic liquid membranes and absorbents are being developed for capture of CO_2 from power plants. Ionic liquid membranes have been developed at NETL for pre-combustion applications that surpass polymers in terms of CO_2 selectivity and permeability at elevated temperatures.

—Field projects have demonstrated the ability to "map" CO_2 injected into an underground formation at a much higher resolution than previously anticipated and confirmed the ability of perfluorocarbon tracers to track CO_2 movement through a reservoir.

—The Carbon Sequestration Regional Partnerships have brought an enormous amount of capability and experience together to work on the challenge of infrastructure development. Together with DOE, the Partnerships secured the active participation of more than 500 individuals representing more than 350 industrial companies, engineering firms, state agencies, non-governmental organizations, and other supporting organizations.

—The Partnerships are conducting field tests to validate the efficacy of carbon capture and storage technologies in a variety of geologic storage sites throughout the United States and Canada. Using the extensive data and information gathered during the initial stages of the project, the 7 Partnerships identified the most promising opportunities for carbon sequestration in their Regions and are performing 25 geologic field tests.

Developing the technologies needed to support a widespread expansion of CO_2–EOR could substantially increase existing U.S. reserves and production. The DOE efforts listed above are providing the elements needed to enable this expansion by advancing capture technologies to ensure a reliable low-cost supply of CO_2 and improved EOR technologies to optimize for carbon sequestration co-benefits.

Mr. Chairman, and members of the subcommittee, this completes my statement. I would be happy to take any questions you may have.

Senator DORGAN. Mr. Bauer, thank you very much. Let me begin by asking about the costs involved. It is one thing to say let's capture carbon. It's quite another thing to determine the impact or the cost. Will it be economically feasible to capture the carbon? Will this destroy projects that are on the drawing boards because it's just way too expensive? Are you a pointy-headed researcher who loves to talk in theory about things in practice not achievable? So tell me—well, I know you're not a pointy-headed researcher.

But tell me, if you will, with what capability we can, in a realistic way, capture carbon and use it for beneficial use?

Mr. BAUER. I think that's a very important comment and question. While we can capture—many people make the case that we can capture or separate CO_2 today, the economics around it are prohibitively expensive. Just to give you a quick, round number, if we took the 300 gigawatts of coal-powered generation today and said that 50 percent of it was going to have to be—of the CO_2 produced would have to be captured and done away with, put in the ground, that would increase the price of electricity from an average of $25 a megawatt for those plants to almost $80 a megawatt. That's a substantial increase. It would reduce the power delivered by about 42 gigawatts. That's about a 15 percent reduction. Or to put it in other terms, we would have to find 42 gigawatts of additional electricity to make up for the electricity utilized in the carbon capture and storage. So while we can do it, the potential impacts are substantial.

To give you a perspective, a megawatt of natural gas right now is about $65 a megawatt, in round numbers. So right now coal is keeping the price of electricity down, and nuclear power also contributes to that. This would raise the price. But if we were to say we would offset that 42 gigawatts by an additional use of natural gas, we would have to find for every 25 gigawatts of additional natural gas, 1 trillion cubic feet of additional natural gas supply, which is already a challenge to the United States in that we import about 18 percent of our natural gas, and we would have to substantially increase that number to meet that additional. Or another way to think about it, the Alaskan Pipeline for natural gas is about 1.6 trillion cubic feet a year of natural gas when it's in place, so we are looking at one and a half natural gas pipelines just to make up for that CO_2 cost right now.

Senator DORGAN. Are there some applications from which it is harder to extract and capture CO_2 than others, and, if so, what are they?

Mr. BAUER. At present most of our coal fleet is a pulverized coal combustion-type fleet, and the flue gas that comes out of those combustion plants is very dilute, and so it's much more difficult to capture CO_2 from this juncture. Dakota Gasification is a gasifier. It converts coal into a synthetic gas. Methanization makes it pipeline grade natural gas equivalent. Right now that CO_2 is at a higher concentration, so that's more readily separable and a better economic perspective and, therefore, it looks like now that those plants have a slight advantage on price in dealing with CO_2 in complexity.

There are technologies coming forward that look at using more oxygen and less air in firing pulverized coal plants, which would increase the concentration of CO_2, but those are probably 8 to 10 years from real commercial application.

Senator DORGAN. Describe for me the work, if any, that you have done on lignite coal.

Mr. BAUER. We've done quite a few different kinds of work on lignite coal, everything from—and, in fact, EERC has been a major partner in some of that. We're looking at the transport gasifier. It's a different version of gasification. And it's almost like a fluidized bed coal plant. It moves the coal through the system and it works to the advantage of the lignite-type and Powder River Basin-type coal for its utilization. We've worked on environmental separation of mercuries and other emissions from the coal. There's been work with Basin Electric actually in drying lignite coal, which has high water content, and that reduces the energy penalty on that. And some of the Clean Coal projects that have gone forward have demonstrated these technologies at a reasonable scale for them to go to commercial application. I believe they are going to commercial application.

Senator DORGAN. In your judgment, what's the highest valued and best use of lignite coal?

Mr. BAUER. I think the best use for lignite coal is a combination of either electricity production, as it has been used to a large degree, or gasification, as the Dakota Gasification Plant has proven is possible and commercially viable, possibly even using it for a source of feedstock for coal-to-liquids, azeotrope-type liquids, which are a diesel-type liquid, or even potentially to gasoline product. And with the price of oil per barrel and the high concentration of CO_2, I think they're a viable possibility that it could still compete readily in the marketplace with CO_2 as a product that has to be dealt with either by way of a product or as a way of a waste.

Senator DORGAN. Lignite coal, to our chagrin, is sometimes referred to as a low-rank coal.

Mr. BAUER. Yes, sir.

Senator DORGAN. Describe for me, if you could, in terms of the other uses, the uses other than producing electricity, coal-to-liquids, coal-to-synthetic gas, coal-to-plastics, and so on, the advantages and disadvantages of lignite coal versus other kinds of coal in those processes?

Mr. BAUER. The reason lignite coal is called low rank is not to imply a value statement, but it's to recognize that bituminous coal is about 13,000 BTUs per pound and lignite coal is about 8,500 BTUs per pound, so it's just relative per-pound BTU value. If you go to use lignite for a nonelectrical application, probably the way one would use it would be to gasify it, which is not to burn it, but to put it in an atmosphere and cause it to kind of give off its value in a gaseous manner. It's still a thermal conversion process. What comes off is largely carbon dioxide, carbon monoxide and hydrogen. You would take and reform it by pressing steam through it to shift the CO to carbon monoxide into additional carbon dioxide and form more hydrogen so that you would have a synthetic gas that comes out of the other side and you could either increase the gas into a methane, a natural gas-type product, or you could take the feedstock and the hydrogen and use it in chemical processes and applications, or you could take the synthetic gas and go through a catalytic conversion and make a gasoline or a diesel-type product, azeotrope process that normally calls for diesel. The other thing you can do with it is to burn it and make electricity out of the hydrogen, and the CO_2 is a high concentration so it's readily stripped off.

Now, that is all in theory and pilot scale practice. The CO_2 issue I, personally, think is more readily dealt with, but there's still an economic challenge, a balance and plant challenge in doing that that we haven't been able to do at a large scale, other than what we've learned at Dakota Gasification, which, as you pointed out, is a major source of insight on the dynamics of doing that.

Senator DORGAN. My understanding is, and I'll ask Ron Harper about this when he testifies, that we capture about 50 percent of the CO_2 from Dakota Gasification, and furthermore that, much like other applications in these coal plants, as you incrementally capture more and more CO_2, the more costly it is per unit of collection. Is that the case with CO_2 in most cases?

Mr. BAUER. The issue for CO_2 is the higher you go, the harder it is to separate what's left out of the—without taking other fuel beneficial. So, for example, if you try to push the limit up towards 90 or 100 percent, you're going to wind up taking away some of the high-value hydrogen with the CO_2 and losing its use or its availability.

On Dakota Gasification, I think it's important to remember Dakota Gasification was not initially designed to be a CO_2 separation and synthetic gas, and so backfitting to separate the CO_2 has certain drawbacks or lack of ability to optimize, and if the plant were designed from today—and I'm sure Ron can either clarify or correct me—you might not do it exactly the same way or you designed it to be more efficient, but still, having said that, the higher you go, the more difficult it becomes and, therefore, the more expensive.

Senator DORGAN. Congress is going to make the judgments ultimately about policy, but you are providing your research reports to Congress and your best advice. We talked earlier about the economics of it. What do you think is achievable in various applications? And, you know, one of the things that we've discussed previously is that people who have projects in mind at this point face uncertainty. They don't know what the rules might be. They don't know what the carbon capture requirement will be. They know there will be rules, but they don't know what they will be or over what timeframe or what costs might apply to their projects. What kinds of thoughts do you have about how policymakers should establish the framework here? How should Congress establish that framework?

Mr. BAUER. Well, as you mentioned, Senator, I'm not supposed to be in the policy business. I can only give a technical and possibly some minor economic perspective. I think if we look at the Clean Air Act as some indicator of what it takes to get to some regulatory structure for business decisions to be made, you're talking from the time of final legislation to actually the publication of regulation and rules against which decisions are made so they have to meet these requirements or be found in violation. It can be an 8- to 10-year process to get through the publication of regulations, the bidding of them, and even the challenges in court before we come out the other end with an area of certainty.

I do know, though, that the regulations for use of EOR exist. So using CO_2 in EOR process, we believe that our indications of the numbers are that, you know, there's 15 to 20 years that EOR could utilize most of the CO_2 that's generated in this country if it were made available to the various sites. If you look at enhanced oil recovery sites, most of them are done in the western Texas, southeastern New Mexico area largely because there's a lot of naturally occurring CO_2 out there that they tap and release from the ground and use it to do EOR. If there were an anthropogenic, manmade CO_2 readily available in quantity and at a reasonable price, and that's where Dakota Gasification is a model, that's why the Saskatchewan oilfields buy their CO_2, they can get it at a competitive price that makes it a very viable source of EOR for them, they'll take as much as they can give them right now, then it makes a different dynamic.

So one thing we might be thinking about as we're trying to deal with the CO_2 issue, the greenhouse gas issue, how do we recognize the value of EOR in a way that stimulates coal-powered generation, coal gasification liquids to utilize that as a means for the first decade of the plant's operation without having to worry about the significant challenges of storage and liability and long-term storage, and what are the Federal, State and local issues and regulations required for them to make a business decision. So that might be a way forward at least to provide some near-term certainty.

Senator DORGAN. Your principal research is in the area of coal, and yet in your testimony both before the Congress and also at this hearing about the beneficial use of CO_2, you're talking about enhanced oil recovery. Your research includes that?

Mr. BAUER. Yes. Our research really is all fossil fuels, and actually we do some in the area of biomass and renewables.

Senator DORGAN. Let me ask—you know, the room is not exactly full of people from the oil industry. And oil is at $73 a barrel this morning.

Mr. BAUER. Right.

Senator DORGAN. Following your testimony before the Energy Committee a while back, it seems to me that if, at $73 a barrel, you can effectively capture CO_2, use it for the beneficial purpose of enhancing oil recovery, it certainly should be attractive. What's your experience with respect to the oil side of this? We've been talking about the coal industry, but what about the oil industry? Are they interested, excited? Tell me about your work with them.

Mr. BAUER. Well, I think it depends on the company really and the geographical region that you're talking. If they're in a region where they have potential oilfields that need CO_2 to further produce, at this present value of a barrel of oil at $70, $74 per barrel, they would love to produce more oil from those fields, and if they don't have a CO_2 source handy, they're very interested in finding one if the economics around it are meaningful.

One of the problems sometimes is the utility that has the CO_2 possibly has to actually backfit their plant to put the capture technology on. That can be quite expensive. We're not talking about millions or tens of millions.

We're talking about maybe $200 or $300 million to put on a separation technology depending on the scale of the plant, but you would want a larger-scale plant to offset the cost, and then you have to move it over there, so one of the wrestling issues is who pays for the capture, who pays for the pipeline. If you look at the requirements now, I think it would be difficult for a utility to go before their utility commission board and ask to build that into their rate base case with no law requiring them to do that. So, unless they could show that the economics make sense, they may have difficulty with that, or the same thing from the standpoint of their investors or if it's an independent electricity producer.

Senator DORGAN. But at $73-a-barrel oil—you indicated you think there's 200 billion barrels of oil, potentially recoverable over time, that's residual in the pools?

Mr. BAUER. Let me just clarify that.

Senator DORGAN. Clarify that, if you would.

Mr. BAUER. There's 200 billion barrels. However, those may be technically recoverable but not economically viable. That's one of the problems right now. A reason we've only done a billion barrels of EOR is in many cases it's not economically viable. The price of the CO_2 or the ability to get it to where it's located offsets the potential profitability.

Senator DORGAN. What are they recovering in Canada with the CO_2? Do you know? Probably Ron does.

Mr. BAUER. I think they're doing about 5,000 barrels a day, so that's very nice when you think of the price right now, and Ron knows better than I what the price of CO_2 is, but my understanding is it's very competitive in the CO_2 marketplace right now. CO_2 down in West Texas is going for about $20 a ton. So it's probably less than that in certain areas, and from a plant that would probably be a high number right now, if anybody would be willing to pay more than that, and you've got to figure the cost of separation equipment and the movement of the CO_2 to the site that it would use. So I think there's a lot of need to foster the dynamics between the utility and the potential oilfield user to encourage that.

Senator DORGAN. Is the location of our coal fields in North Dakota, the Fort Union Basin and so on, relative to the oil activity that goes on in North Dakota and Montana—I assume that's beneficial in terms of some future construct of using CO_2 capture for enhanced oil recovery?

Mr. BAUER. I think that could be very possible. And I think what would have to be set up would be the infrastructure to move the CO_2 from those plants to the fields, which I don't think is a great technical challenge, but someone has to decide the business opportunity makes sense or someone wants to foster that. And the same thing I think in the Montana, Wyoming oilfields. I know the State of Wyoming has been very interested in talking about those things, too.

Senator DORGAN. Franz, do you have any questions?

Mr. WUERFMANNSDOBLER. Mr. Bauer, if we were to set aside the question of funding levels, what is the most critical technology or program type of activity that you think would be necessary to more substantially move forward so we can prove some of these technologies out so they could be commercially viable, say, within 5 to 10 years?

Mr. BAUER. There are two, what I would suggest, major areas of high cost. One is the actual separation or capture of the CO_2. As the Senator mentioned, there has been an increase in the Senate mark, and also the House actually recognized the capture challenge that would go a long way to moving forward more aggressively to take pilot scale or laboratory scale—not necessarily our laboratory, by the way—across the country, capture technology up to the point where they could be commercially viable within the next decade or less. That would be tremendously helpful, because at the present previous funding we're probably 20 years away.

The other is doing large-scale evaluations and demonstrations of putting a million ton-plus of CO_2 into the ground. Again, the committee's work and recent funding there, I think, makes that more probable in the near term, and that's where we're working with the regional partnerships—there's several regional partnerships, each of them, beginning next year to be headed towards sticking a million tons of CO_2 into storage reservoirs to confirm what the science says and the oil experience tells us is a viable place to store CO_2 long term indefinitely. That will take probably 7 or 8 years before we go through the full cycle of setting up testing, injecting the CO_2, monitoring and further study and analysis for a couple years to confirm our results.

So those are two major areas. I think another area, though, which is maybe less expensive, but maybe makes it more challenging, is for the general public and population, local regulators, to understand the viability of carbon storage in reservoirs so that they would accept it and the permitting process would be a reasonably standard process and a high confidence that no one would be in any way harmed or threatened by what was done there, and that will take some funding to provide the opportunities to provoke participation and education of those who have to be involved in that process and the surrounding public to be fully informed and given a chance to work through what does that mean to them.

Mr. WUERFMANNSDOBLER. Are there any other issues that you think would be beneficial so that the general public would better understand or the interested industries would better understand the opportunities here?

Mr. BAUER. I think with the—in the last year especially, the discussion around greenhouse gas has begun to get people to be paying attention to what are the alternatives, what can we do about it. I think more information in, what I would say, a comprehensible manner. As you mentioned, us pointy-headed R&D folks sometimes talk in ways that we assume will probably make sense, and I'm sometimes told at home I don't make much sense. But, at any rate, that the public could understand the magnitude of this challenge and the magnitude of the threat, quite frankly, to their own energy and the Nation's energy security. I don't think that's really comprehended. So providing a way to communicate that in a balanced manner because, while I support energy from all sources, I believe our answers come from all energy sources, I think we need to honestly understand what each source has the high potential contributing and the more pragmatic actuality of contributing. And so trying to put all our eggs in any one basket is not a good answer, but trying to find a balance—and I know that's what you're working on, Senator, and Senator Domenici, as well—a balanced portfolio of technologies to contribute to the energy future of this country in an economically acceptable way, I think is important for our public to understand. I don't think they really understand it the way they should.

Senator DORGAN. I think that's an important point. I'm a strong supporter of renewable energy—all kinds of renewable energy, but that doesn't mean we're not going to need to use fossil fuels in our future. We are. The question is not whether. The question is how do we use those, and that's why this research is critical.

What I would like to do, Mr. Bauer, is, with your permission, call up the second panel. I would like you to, if you would, take a chair at the end of table and be available for questions that might be raised by the other panel. We appreciate your work at the National Laboratory and appreciate your being willing to come here to North Dakota this morning.

I want to also mention that Roger Johnson, the State Agriculture Commissioner, is here with us and Susan Wefald, the Public Service Commissioner. Where is Susan?

Ms. WEFALD. Right here.

Senator DORGAN. Thank you for being with us. If I'm missing somebody, let me know. Thank you for being with us. I know both the Agriculture Commissioner, serving on the Industrial Commission, and the Public Service Commission have very significant interests in both of these issues, and I appreciate both of you being at this hearing.

Next I would like to call Ron Harper, the chief executive officer of Basin Electric Power Cooperative, to come up; John Weeda, John is the plant manager of the Coal Creek Station at the Great River Energy Company; Rod Nelson, vice president, Schlumberger Limited, on behalf of the National Petroleum Council; and Jeffrey Phillips, the program manager, Electric Power Research Institute. Mr. Harper and Mr. Weeda are both with us from North Dakota, and my understanding is, Mr. Nelson, you're from Texas.

Mr. NELSON. Right.

Senator DORGAN. And, Mr. Phillips, you have come to us from New York City.

Mr. PHILLIPS. Charlotte, North Carolina.

Senator DORGAN. Charlotte, North Carolina, big difference, sorry about that. Accept my apologies.

Let me turn to you, Mr. Harper. Thank you for being here and, as with all of you, your complete statements will be made a part of the permanent record and you may summarize those as you wish.

STATEMENT OF RONALD R. HARPER, CHIEF EXECUTIVE OFFICER AND GENERAL MANAGER, BASIN ELECTRIC POWER COOPERATIVE

Mr. HARPER. Thank you, Senator, and I very much appreciate on behalf of Basin the opportunity to come before this committee to talk about some critically important, what we believe is our future, with respect to energy development.

Senator DORGAN. Can you pull that microphone a little closer so that we can hear you better? Thank you.

Mr. HARPER. Is that better?

Senator DORGAN. Yes, much better.

Mr. HARPER. I would like to put three bullets or stakes in the ground. First of all, many throughout the electric industry are in the process of developing coal-based plants to meet this growing economy's need, and in the coming years we have to figure out how to utilize these plants more efficiently with respect to greenhouse gases. The second point is we strongly believe that coal must remain a viable part of this country's energy future. And, lastly, the Federal Government needs to undertake an aggressive strategy to mitigate the risk of a carbon-constrained future while at the same time balancing the needs of our growing economy.

Basin believes that we are on the threshold of tremendous opportunity with respect to continuing the use of fossil fuels in this country. Technology must, however, be developed to use this resource much more wisely and efficiently, including addressing how to capture carbon dioxide. The Energy Policy Act of 2005 was a step in the right direction by providing tax incentives, loan guarantees and other programs to encourage the commercial development of the next generation of clean coal technologies.

Much has been said already this morning about the Dakota Gasification project, the Great Plains Synfuels Plant, and we believe that has been the step to this future and how we might manage in a carbon-constrained environment.

As was mentioned by the earlier presenter, we are a major player in the Plains CO_2 Reduction, or PCOR, Partnership. We are also involved in the Canadian Clean Coal Power Coalition. But, more importantly, we are doing it. We are capturing carbon and providing sequestration opportunity in the Canadian oilfields. We have so far sequestered 10 million tons of CO_2, and it is our belief that the CO_2 is being permanently sequestered in those oil fields through an opportunity through enhanced oil recovery.

As we look at developing generation in today's time frame, we're looking at two technologies. IGCC, or integrated combined cycle, is one technology. The other one is what we call supercritical, or our pulverized coal type of technology. As has been said, capturing carbon off of a gas facility is much easier than trying to capture carbon off an existing PC facility.

It's because of those things that we are engaged in activities at our Antelope Valley Station in conjunction with the Dakota Gasification project to understand how we might capture carbon off the back end of an existing pulverized coal facility. Our plan currently is to find a vendor that will have the right technology that matches up with what we're trying to get accomplished, capture CO_2 off of the Unit I facility there at Antelope Valley and pipe it around to the existing infrastructure at Dakota Gasification. We then would look for customers for enhanced oil recovery in western North Dakota, eastern Montana, to avail ourselves of an opportunity to help offset the costs of that kind of technology.

We believe that enhanced oil recovery is a bridge or a financial incentive to carbon capture. Again, the costs associated with this technology are extremely immense in our view, and so somehow there has to be a revenue stream to help offset those costs. We believe that there are opportunities out there to develop this technology. Our vendors' list is about nine at this point throughout this country. We've offered five on-site visits so far, so we believe there's a lot of interest in the same concepts that we're pursuing.

PREPARED STATEMENT

One of the things that we think is also important, much like what you're trying to do within your committee, is to develop an opportunity to provide incentives for this research and development opportunities and ultimately to full-scale production that will again enhance our opportunity to continue to burn fossil fuels in this country.

Mr. Chairman, that concludes my remarks and I would stand ready to address any questions that you or the other committee members might have. Thank you.

[The statement follows:]

PREPARED STATEMENT OF RONALD R. HARPER

Mr. Chairman and members of the committee, my name is Ron Harper and I serve as the CEO and General Manager of Basin Electric Power Cooperative. I appreciate the invitation to testify today, and I am here to provide you with Basin Electric's views on the future of coal as a fuel source for power generation, and Basin's efforts to address CO_2 emissions from coal plants, while at the same time enhancing opportunities to increase domestic oil supply. The electric industry is going to build significant numbers of power plants, many of them coal-based, in the coming years to meet our Nation's growing electrical demand. The question of what to do with the carbon dioxide produced by these plants is casting a shadow over their viability. Coal is a vital part of our Nation's energy security, and the Federal Government should undertake an aggressive strategy to mitigate the risk of a carbon constrained future. For its part, Basin Electric is taking a leading role in finding these answers.

A COMPREHENSIVE SOLUTION TO A COMPLEX PROBLEM

Basin Electric is an electrical generation and transmission cooperative with 124 member cooperatives located in 9 States. Our generation resources include approximately 3,500 megawatts of coal, gas, oil and wind, but we are primarily a coal-based utility. As we look to the future, we know we must look at a broad range of solutions ranging from efficiency and conservation, to renewable energy, natural gas, and nuclear and how to utilize coal more efficiently.

Basin Electric is committed to a diverse fuel mix in its generation portfolio. Today, Basin Electric has one of the largest wind energy resources in the region, with 137 megawatts of wind power. Our board recently approved plans to construct two 100-megawatt wind farms in North and South Dakota respectively which will be the first cooperatively-owned wind farms in the country. Basin Electric also utilizes four "one-of-a-kind" recycled energy systems, which use waste heat to produce 22 megawatts of power without any additional fuel consumption or emissions. Four more of these systems are scheduled to be built in the near future.

In November 2005, our membership adopted a goal that by 2010, Basin Electric would have renewable resources in its generation portfolio in an amount equal to 10 percent of the capacity needed to meet the demands of our members. With our existing and planned wind and recycled energy projects, we are well on our way to achieving that goal. However, Basin Electric needs significant base-load generation and, for the foreseeable future, that will come from coal.

COAL—A NECESSARY PART OF THE SOLUTION

Basin Electric is growing and we are looking at developing new base-load generation. After reviewing all of our options, it became clear to us that to meet our needs for low cost base-load power, the best choice was coal. Both North Dakota and Wyoming have ample supplies of coal and we have considerable knowledge of building and operating coal-based generation plants. We have built gas generation for peaking purposes and will build more. However, we do not believe it is prudent to build base-load gas generation and expose our membership to significant fluctuations in natural gas prices. To provide base-load power, Basin Electric is developing two coal-based facilities, one is the Dry Fork Station in Wyoming and the other will be located either in North Dakota or South Dakota.

Coal provides 50 percent of the electricity generated in the United States. It is our most abundant domestic resource and will continue to play an important role in meeting our Nation's energy needs. However, new technology must be developed to use this resource more wisely and efficiently, including addressing how to capture the CO_2 emissions. The Energy Policy Act of 2005 was a step in the right direction in providing tax incentives, loan guarantees, and other programs to encourage the commercial development of the next generation of clean coal technology.

AN EXAMPLE FOR THE FUTURE—THE GREAT PLAINS SYNFUELS PLANT

The questions surrounding carbon dioxide emissions from coal-based facilities complicate future development. These CO_2 questions must be answered to ensure coal's continued place as a reliable, low-cost fuel source. I believe that part of the answer to these questions exist at Basin Electric. Basin Electric is taking a leading role in several carbon initiatives, including its membership in the Plains CO_2 Reduction (PCOR) partnership and work with the Canadian Clean Power Coalition.

However, the best and largest example of low-carbon coal is through Basin Electric's subsidiary Dakota Gasification Company, which owns the Great Plains Synfuels Plant in Beulah, North Dakota. In 2000, DGC began delivering carbon dioxide to oil producers in Saskatchewan, Canada. We currently capture roughly 49 percent of the CO_2 produced at the plant, and ship it to Canada through a 205-mile pipeline to Weyburn, Saskatchewan to be used for enhanced oil recovery (EOR) in an aging oil field. Today, DGC provides all the CO_2 to the largest carbon sequestration project in the world. Through 2006, Dakota Gasification has successfully captured and marketed over 10 million tons of carbon dioxide to two Canadian customers. Total carbon dioxide demand is 152.7 million standard cubic feet per day. The carbon dioxide is expected to be permanently sequestered in the oil reservoir and is being monitored by the International Energy Agency (IEA) Weyburn CO_2 Monitoring and Storage Project.

TWO PATHS FORWARD FOR COAL

We have learned a great deal about what works and what doesn't work with carbon capture and sequestration over the last 7 years. The Synfuels Plant, however, is unique. The plant produces synthetic natural gas that is pipeline quality. Given the major differences between producing pipeline quality gas and producing gas to generate electricity, it is not a simple task to translate this technology to power production. When building new coal-based generation, a utility has somewhat limited technology choices. The two most prominent include: Integrated Gasification Combined Cycle (IGCC) or supercritical (ultra-supercritical) Pulverized Coal (PC).

IGCC Option

Integrated Gasification Combined Cycle (IGCC) uses the same basic concept in operation at the Synfuels Plant. However, an IGCC power plant would not need to purify the gas to a high degree for the gas to be used in a combustion turbine to produce electricity. The cost of a new 600 megawatt (MW) IGCC power plant is anywhere from 10 to 20 percent higher than a comparable Supercritical PC plant. Adding carbon capture equipment on the back end considerably increases those costs, and the expense of efficiency.

We are confident that the carbon capture would work on an IGCC facility. However, we are not sure that low rank coals, such as lignite and sub-bituminous, will work effectively in an IGCC facility. Basin Electric and the Lignite Energy Council have sent North Dakota Lignite to the Department of Energy's IGCC testing facility in Alabama in the past, but the testing raised questions with respect to the sodium content of lignite. This has delayed any long-term testing that could readily answer questions about how IGCC works on low rank coals. The same is true for sub-bituminous coal, as most of the testing and commercial application of the technology remains focused on low-moisture, eastern bituminous coal.

In 2006 Basin Electric partnered with General Electric and Bechtel Corporation to submit an application to the Department of Energy for tax credits to construct a new power plant in South Dakota which would use Integrated Gasification Combined Cycle (IGCC) technology. Unfortunately, due to problems with the authorizing statute, no projects using sub-bituminous coal, such as this one, were considered. That legislation has since been fixed, and Basin Electric and GE are reviewing our options to submit a second application for the 2007 round.

PC Option

While IGCC has its own questions regarding low-rank coals, Basin Electric is confident that a supercritical PC plant will work with low-rank coals to generate power. On the other hand, carbon capture technology has not been developed for PC plants. Much of the technology is in early development and needs further research. There are hundreds of pulverized coal plants still operating around the country that have decades of useful life left. These plants cannot be shut down or converted overnight, so a way must be found to capture and sequester the CO_2 from these facilities as well. Supercritical PC plants can be just as efficient as an IGCC plant, so they should be considered for similar incentives to help capture and sequester carbon dioxide.

In order to facilitate the development of this technology, Basin Electric recently issued a Request For Proposal to demonstrate carbon dioxide capture at one of our existing plants, the Antelope Valley Station. CO_2 would be captured from the flue gases at Antelope Valley, piped to the neighboring Great Plains Synfuels plant, and added to the existing CO_2 pipeline system. This would add nearly 60 million standard cubic feet of gas to the pipeline for enhanced oil recovery in North Dakota's Williston Basin or at other regional sites. We currently estimate the cost of demonstrating carbon dioxide capture on a small portion of the 900 MW plant, around 100 MWs, would be roughly $100 to $150 million. We have received several responses, and have met with interested vendors on site, and are in the process of evaluating their proposals.

TECHNOLOGY HORSERACE—A BALANCED APPROACH TO INCENTIVES

Federal incentives need to be technology neutral. Supercritical PC and IGCC both have a place in our Nation's electricity portfolio. At this point and time there is no clear indication that one of these technologies will become the choice for capturing and sequestering carbon. The Investment Tax Credit (ITC) authorized in the Energy Policy Act of 2005 is essential for building the first plant to demonstrate a "carbon capture ready" IGCC plant using low rank coals. In addition, the Senate Finance Committee recently proposed a $10 per ton production tax credit for carbon capture and coal facilities. Both of these incentives need be to available in the future if viable technology solutions are to be fully explored.

ENHANCED OIL RECOVERY—A BRIDGE FOR TECHNOLOGY

Enhanced oil recovery can provide a financial incentive to carbon capture. The current effort to sequester carbon from coal based facilities requires intensive capital. Enhanced oil recovery can provide one mechanism to reduce that cost. However, even the potential for revenue from selling CO_2 does not fully support the business case of adding carbon capture to a plant. A combination of construction and production incentives is necessary to such a system financially and commercially viable. A $10 per ton production tax credit for carbon sequestration would provide this support, and benefit both IGCC and pulverized coal, without discriminating against the generation process used. Add to that a $250 million investment tax credit, and you would go a long way to enhance the prospect of building IGCC and PC plants that capture carbon dioxide.

Mr. Chairman, in conclusion, the Energy Policy Act provides important tools in helping build the next generation of coal-based power plants. These tools need to be expanded to provide electric utilities with the assistance they need to develop the next generation of power plants and efficiently capture and sequester carbon dioxide from existing and future power plants. Thank you again for holding this important hearing. I am available to answer any questions.

Senator DORGAN. Thank you very much. Next we'll hear from John Weeda from Great River Energy Company. Thank you for being here.

STATEMENT OF JOHN WEEDA, PLANT MANAGER, COAL CREEK STATION, GREAT RIVER ENERGY

Mr. WEEDA. Thank you, Senator Dorgan, and thank you for the privilege of testifying here today.

Great River Energy owns and operates generation facilities in North Dakota, and we want to expand those facilities in the State, and those plans include innovative uses of coal to allow us to meet growing energy needs and help reduce the country's dependence on foreign oil, and do it all in an environmentally sensitive manner.

Our existing plants are reliable and they are regularly updated to incorporate updates in emission controls and enhance the operations.

Great River Energy plans to build a third power plant in North Dakota, the Spiritwood Station. It's a 99-megawatt combined heat and power facility located about 8 miles east of Jamestown, North Dakota. As a combined heat and powerplant, Spiritwood will generate electricity for the electric grid and steam to power the neighboring malt plant and a proposed 100-million-gallon-per-year ethanol plant. Doing so will be a highly efficient operation, about 66 percent compared to most coal-based plants are 30 to 35 percent efficient. It's because of taking advantage of the energy which would normally be released to the cooling towers.

Fuel for the coal-based combined heat and power plant will be beneficiated lignite, supplied by Great American Energy. Highly efficient technologies such as combined heat and power offer additional opportunities for the reduction of regulated emissions and carbon dioxide, as well.

Great River Energy is also commercializing an innovative coal-drying technology that was developed at Coal Creek Station. This process uses waste heat from the powerplant to improve the quality of the lignite, and, as a result, Coal Creek Station will use approximately 10 percent less coal and the plant's efficiency will increase approximately 5 percent. In addition, emissions are expected to be reduced, as well as plant maintenance. The efficiency improvements also result in less CO_2 per megawatt of electricity generated. The coal dryer also removes mercury. And Great River Energy is proud to comment that we partnered with the U.S. Department of Energy's Clean Coal Power Initiative on this project.

We also use additional steam from Coal Creek Station to power the Blue Flint Ethanol Plant. And because a majority of the ethanol energy required is waste heat from the adjacent Coal Creek Station, Blue Flint Ethanol did not have to build a $25 million boiler, thus making it a low-cost source of ethanol. Because the plant is collocated with Coal Creek Station, it has fewer emissions and uses less water compared to an ethanol plant at a Greenfield site.

Great River Energy, Headwaters Energy Services and North American Coal Corporation are exploring the development of a North Dakota-based coal refinery to produce ultra clean transportation fuels and electricity. This polygeneration plant would use about 10 million tons of North Dakota lignite annually. The integrated process would result in about 32,000 barrels of transportation fuel and 150 to 250 megawatts of electricity and other byproducts.

The project would utilize proven technology to capture carbon dioxide emissions from the plant, which would then be utilized for enhanced oil recovery in western North Dakota. It incorporates carbon capture into its design and is expected to remove and sequester 70 percent of the total CO_2 produced in the process. CO_2 would be sold to oilfield operators to use in EOR, which is commercially demonstrated technology for use of CO_2.

As a result, the carbon footprint for American Lignite Energy fuels will be equal to or less than the domestic fuels that they replace and better than fuels derived from imported petroleum. Electricity from the project's generating facility will have CO_2 intensity equal to or better than a natural gas-fired combined cycle plant.

However, if the United States desires a coal-to-liquid industry and more energy independence, the development of the industry will require Federal incentives to help address the financial market risk associated with oil price volatility and commercializing the industry.

PREPARED STATEMENT

All of this activity helps spur the North Dakota economy. Great River Energy is playing a significant role in economic development efforts in North Dakota. Great River Energy is a responsible environmental company and progressive, and we've established a goal to reduce greenhouse gas emissions to below 2000 levels by 2020. To accomplish our goals, we are focused on a number of solutions that support a sustainable environment, including energy conservation, renewable energy sources, carbon capture, storage/sequestration research, and other initiatives.

Thank you, Mr. Chairman, and I would be pleased to answer your questions.

[The statement follows:]

PREPARED STATEMENT OF JOHN WEEDA

Mr. Chairman and members of the subcommittee, my name is John Weeda. I am Great River Energy's plant manager at Coal Creek Station near Underwood, North Dakota. Thank you for the opportunity to testify today.

Great River Energy is a generation and transmission cooperative based in Elk River, Minnesota. that provides wholesale electric power to 28 distribution cooperatives. We own power generation facilities in North Dakota and plan to expand our operations in the State. Those plans include innovative uses of coal that will allow us to meet growing energy demands and help reduce the country's dependence on foreign oil—all done in an environmentally sensitive manner.

Great River Energy's existing coal power plants—Coal Creek Station and Stanton Station—are reliable and efficient baseload generating stations. We regularly update their emissions controls and enhance their operations. Great River Energy values its reputation as an environmental leader among utilities. We have made a strategic commitment to environmental stewardship and are acting on the evidence that climate change is real by pursuing initiatives that support a sustainable environment. Our commitment is based on our core operating principle to make the right environmental choices within our technological and financial capabilities.

Great River Energy plans to build a third power plant in North Dakota—Spiritwood Station—a 99-megawatt combined heat and power facility, located about 8 miles east of Jamestown, North Dakota, near Spiritwood. As a combined heat and power plant, Spiritwood Station will generate electricity for the electric grid and steam to power a neighboring malting plant and a proposed 100-million-gallon per year ethanol plant. Doing so results in a highly energy efficient power plant—at about 66 percent, as compared to most coal-based power plants which are about 30 to 35 percent efficient. This is because the plant will take advantage of the energy in the steam which is normally released to cooling towers.

Fuel for the coal-based, combined heat and power plant will be beneficiated lignite, supplied by Great American Energy. The lignite product will be 7,500 Btus per pound with 25 percent moisture (upgraded from 6,200 Btus per pound with 38 percent moisture). The power plant would also use Best Available Control Technologies to meet and exceed the stringent health based air quality standards.

Construction of Spiritwood Station would begin following approval of the plant's air emissions permit by the North Dakota Department of Health. If granted this September, the plant would then be scheduled to start operating in the first quarter of 2010—following 2.5 years of construction.

Highly efficient technologies such as combined heat and power offer additional opportunities for the reduction of regulated emissions and carbon dioxide (CO_2). Great River Energy supports the development of Federal and State-level incentives for the development of these facilities that provide electricity while producing steam that can be used to power other industrial operations.

Great River Energy is commercializing an innovative coal drying system that was developed at Coal Creek Station. The process uses waste heat from the power plant to improve the quality of lignite. As a result Coal Creek Station will use approximately 10 percent less coal, and the plant's efficiency will increase approximately 5 percent. In addition, emissions are expected to be reduced, as well as plant maintenance. The efficiency improvement also results in less CO_2 per megawatt of electricity generated. The coal dryer also removes mercury. Eight dryers will be built at Coal Creek Station, four for each of the plant's two units, with full operation of the system expected by mid-2009. Great River Energy partnered with the U.S. Department of Energy's Clean Coal Power Initiative on the project. Great River Energy will work with partners such as Headwaters and North American Coal to market this technology to other power plants that utilize lignite or subbituminous coal. Great River Energy and North American Coal Corporation have formed a new organization called Great American Energy to sell additional beneficiated lignite to other coal consumers in North Dakota.

We use additional steam from Coal Creek Station to power the Blue Flint Ethanol plant. Great River Energy is a minority owner and service provider for the ethanol plant, a 50-million-gallon per year plant near Underwood. Headwaters Incorporated is the majority owner and operator. Because a majority of the energy for the ethanol plant is waste steam from the adjacent Coal Creek Station, Blue Flint Ethanol did not have to build a $25 million boiler, making it a low-cost source of ethanol. Also, because the plant is co-located with Coal Creek Station, it has fewer emissions and uses less water as compared with an ethanol plant at a Greenfield site. The plant also produces enough distillers grain for about 225,000 head of feeder cattle annually. Carbon dioxide from ethanol plants is a potential for sequestration. Headwaters and Great River Energy are investigating options for a demonstration project.

Our activities are not limited to generating electricity or enhancing ethanol production.

Great River Energy, Headwaters Energy Services and The North American Coal Corporation are exploring the development of a North Dakota coal-based refinery to produce ultra clean liquid transportation fuels and electricity. This polygeneration plant would use about 10 million tons of North Dakota lignite annually. The integrated process would result in about 32,000 barrels of transportation fuels and 150 to 250 MW of electricity and other byproducts.

The partners have completed several preliminary engineering, environmental and market studies, and have started more detailed engineering activities to further their analysis. Final site identification is under way. If the project were to move forward, engineering and permitting of the facility could take at least 2 years. Financing and construction of the facility would take at least 4 additional years. Engineering activities are being supported in part by North Dakota's Lignite Research Fund, with the North Dakota Industrial Commission committing $10 million towards the project.

The project would utilize proven technology to capture carbon dioxide emissions from the plant, which then could be utilized for enhanced oil recovery in western North Dakota. It incorporates carbon capture (CO_2) into its design that is expected to remove and sequester 70 percent of the total CO_2 produced in the process. The CO_2 will be sold to North Dakota oil field operators for use in enhanced oil recovery, which is a commercially demonstrated technology for sequestering CO_2. Enhanced oil recovery has been practiced for decades in Texas and in the Canadian Weyburn fields since 2000. The Williston Basin's demand for CO_2 is projected to be greater than American Lignite Energy's CO_2 production.

As a result, the carbon footprint for American Lignite Energy fuels will be equal to the domestic fuels they replace and better than fuels derived from imported petroleum. Electricity from the project's generating facility will have a CO_2 intensity equal to or better than that of a natural-gas-fired combined cycle plant.

However, if the United States desires a coal-to-liquids industry—and more energy independence—the development of the industry will require Federal incentives to help address financial market risk associated with oil price volatility and commercializing the industry.

All of this activity helps spur the North Dakota economy. Great River Energy is playing a significant role in economic development efforts in North Dakota. Blue Flint Ethanol is a $95 million plant that employs 37 people. The plant purchases corn from North Dakota farmers, and also sells ethanol and distillers grain for about 225,000 feeder cattle per year. Spiritwood Station will cost approximately $275 million and employ about 42 people when operational, and will utilize upgraded lignite from Great American Energy. Great American Energy is a $20 million venture that will have the capacity to supply one to three million tons of upgraded lignite. American Lignite Energy, if built, could be the largest project ever in North Dakota.

Great River Energy is an environmentally progressive energy company. We have established a goal to reduce its greenhouse gas emissions to below 2000 levels by 2020. This is an expected 20 percent reduction from historical emissions despite the fact that we are one of the fastest growing electric utilities in the region. In addition, 25 percent of Great River Energy's energy will come from renewable resources by 2025. To accomplish our goals, we are focused on a number of solutions that support a sustainable environment, including energy conservation, renewable energy sources, carbon capture and storage/sequestration research, and other initiatives.

Mr. Chairman, I would be pleased to answer any questions you may have.

Thank you.

Senator DORGAN. Mr. Weeda, thank you very much. Next we'll hear from Rod Nelson, who comes to us from Texas. He is vice president of Schlumberger Limited, and he is speaking on behalf of the National Petroleum Council. Mr. Nelson, you may proceed.

STATEMENT OF ROD NELSON, VICE PRESIDENT, SCHLUMBERGER LIMITED ON BEHALF OF THE NATIONAL PETROLEUM COUNCIL

Mr. NELSON. Thank you, Mr. Chairman. I appreciate this opportunity, first off, speaking about this important subject of carbon management. And I am representing the National Petroleum Council here today and the oil and gas industry, if you want to ask some questions later.

The National Petroleum Council recently completed a study and presented to Secretary Bodman, a study of the energy future entitled Facing the Hard Truths about Energy.

Senator DORGAN. Can you pull that microphone just a little closer?

Mr. NELSON. Is that better?

Senator DORGAN. Better, yes.

Mr. NELSON. Let me give you a very brief summary of the findings of that study then I'll go quickly to the carbon capture and sequestration question.

The National Petroleum Council examined a broad range of global energy supply, demand, and technology projections through 2030. The Council identified risks and challenges to a reliable energy future and developed strategies and recommendations aimed at balancing future economic, security, and environmental goals. The Council proposed five core strategies which must be addressed together.

First, moderating the growing demand for energy by increasing efficiency.

Next, expand and diversify production from all economic, environmentally acceptable energy sources, as you've already heard.

Integrate energy policy into trade, economic, environmental, security, and foreign policies.

Enhance science and engineering capabilities and create opportunities for research and development.

And, finally, because we are likely moving into an era in which carbon emissions will be constrained, develop the legal and regulatory framework to enable carbon capture and sequestration (CCS). In addition, as policymakers consider options to reduce CO_2 emissions, provide an effective global framework for carbon management, including establishment of a transparent, predictable, economy-wide cost for CO_2 emissions.

So with that background, let me now speak more directly to carbon capture and sequestration, which we think can facilitate the continued use of fossil fuels that we have already discussed. Carbon capture and sequestration, or CCS, entails trapping CO_2 at the site where it's generated and storing it for a period sufficiently long—several thousand years, one would guess—in geologic targets, probably spent oil and gas reservoirs or deep saline formations.

The technologies required for effective CCS are, by and large, viable today. Projects include Sleipner, Weyburn, which you heard about, In Salah saline formation project in Algeria. The hurdles to implementation are largely ones of integration and scale. To put things in perspective, sequestering CO_2 emissions from a one-gigawatt coal-fired power station requires pumping into the ground about 150,000 barrels per day of supercritical or liquid CO_2.

While the technologies for CCS are essentially available and viable, in that capture and storage can be implemented now, extensive scope remains for improvement. In particular, the capture stage of CCS is the key, and you've already heard that from Carl and that dominates the overall cost.

It's important to note that there is no experience available with a full-scale integration process today, in other words, a coupled, large-scale coal-fired powerplant with CCS. Several projects worldwide, most notably FutureGen in the United States and Zero-Gen in Australia, are in the process of designing such an experiment. Operating such facilities successfully is central to understanding the true economics and practical requirements for large-scale CCS.

One activity in which CO_2 is pumped into reservoirs currently is enhanced oil recovery (EOR). This provides a proving ground for various techniques that are relevant to CCS, and can be implemented while other carbon management solutions are under development. At present, most CO_2 EOR is not directed toward effective storage of CO_2, but the techniques can be modified to improve carbon sequestration for longer term.

PREPARED STATEMENT

So let me try to summarize. The challenges facing our energy future are daunting, but not insurmountable. Given the massive scale of the global energy system and the long lead times necessary to make significant changes, concerted actions are needed now to promote U.S. competitiveness by balancing economic, security, and environmental goals. Carbon dioxide emissions are by their very nature a global issue, and atmospheric concentrations respect no geographic boundary. As such, ultimately a global solution is required. Carbon capture and storage is in some ways a unique opportunity for the United States to develop technology and demonstrate leadership. We have large remaining fossil fuel reserves which could be economically and environmentally converted using carbon capture technology. We have the infrastructure and the sedimentary basins to sequester the CO_2. The regulatory and legislative framework within which CCS is conducted will have a major impact on how rapidly the technology is implemented. The oil and gas industry has the skill sets to further develop and deploy this technology, but, clearly, cross-industry and government cooperation is required. Thank you.

[The statement follows:]

PREPARED STATEMENT OF ROD NELSON

Thank you, Senator for the opportunity to testify regarding the important subject of carbon management. I am here representing the National Petroleum Council, which has recently completed and presented to Secretary of Energy Bodman, a comprehensive study of the energy future entitled "Facing the Hard Truths about Energy," and the oil and gas industry. I would like to start by giving you a very short summary of the findings from this landmark study and then delve more deeply into the carbon capture and sequestration opportunity.

NPC REPORT FINDINGS AND BACKGROUND

The American people are very concerned about energy—its availability, reliability, cost, and environmental impact. Energy also has become a subject of urgent policy discussions. But energy is a complex subject, touching every part of daily life and the overall economy, involving a wide variety of technologies, and deeply affecting many aspects of our foreign relations. The United States is the largest participant in the global energy system—the largest consumer, the second largest producer of coal and natural gas, and the largest importer and third largest producer of oil. Developing a framework for considering America's oil and natural gas position now and for the future requires a broad view and a long-term perspective.

During the last quarter-century, world energy demand has increased about 60 percent, supported by a global infrastructure that has expanded to a massive scale. Most forecasts for the next quarter-century project a similar percentage increase in energy demand from a much larger base. Oil and natural gas have played a significant role in supporting economic activity in the past, and will likely continue to do so in combination with other energy types. Over the coming decades, the world will need better energy efficiency and all economic, environmentally responsible energy sources available to support and sustain future growth.

Fortunately, the world is not running out of energy resources. But many complex challenges could keep these diverse energy resources from becoming the sufficient, reliable, and economic energy supplies upon which people depend. These challenges are compounded by emerging uncertainties: geopolitical influences on energy development, trade, and security; and increasing constraints on carbon dioxide (CO_2) emissions that could impose changes in future energy use. While risks have always typified the energy business, they are now accumulating and converging in new ways.

The National Petroleum Council examined a broad range of global energy supply, demand, and technology projections through 2030. The Council identified risks and challenges to a reliable and secure energy future, and developed strategies and recommendations aimed at balancing future economic, security, and environmental goals.

The United States and the world face hard truths about the global energy future over the next 25 years:

—Coal, oil, and natural gas will remain indispensable to meeting total projected energy demand growth.

—The world is not running out of energy resources, but there are accumulating risks to continuing expansion of oil and natural gas production from the conventional sources relied upon historically. These risks create significant challenges to meeting projected energy demand.

—To mitigate these risks, expansion of all economic energy sources will be required, including coal, nuclear, renewables, and unconventional oil and natural gas. Each of these sources faces significant challenges—including safety, environmental, political, or economic hurdles—and imposes infrastructure requirements for development and delivery.

—"Energy Independence" should not be confused with strengthening energy security. The concept of energy independence is not realistic in the foreseeable future, whereas U.S. energy security can be enhanced by moderating demand, expanding and diversifying domestic energy supplies, and strengthening global energy trade and investment. There can be no U.S. energy security without global energy security.

—A majority of the U.S. energy sector workforce, including skilled scientists and engineers, is eligible to retire within the next decade. The workforce must be replenished and trained.

—Policies aimed at curbing CO_2 emissions will alter the energy mix, increase energy-related costs, and require reductions in demand growth.

Free and open markets should be relied upon wherever possible to produce efficient solutions. Where markets need to be bolstered, policies should be implemented with care and consideration of possible unintended consequences. The Council proposes five core strategies to assist markets in meeting the energy challenges to 2030 and beyond. All five strategies are essential—there is no single, easy solution to the multiple challenges we face. However, the Council is confident that the prompt adoption of these strategies, along with a sustained commitment to implementation, will promote U.S. competitiveness by balancing economic, security, and environmental goals. The United States must:

—Moderate the growing demand for energy by increasing efficiency of transportation, residential, commercial, and industrial uses.

—Expand and diversify production from clean coal, nuclear, biomass, other renewables, and unconventional oil and natural gas; moderate the decline of conventional domestic oil and gas production; and increase access for development of new resources.

—Integrate energy policy into trade, economic, environmental, security, and foreign policies; strengthen global energy trade and investment; and broaden dialogue with both producing and consuming nations to improve global energy security.

—Enhance science and engineering capabilities and create long-term opportunities for research and development in all phases of the energy supply and demand system.

—Develop the legal and regulatory framework to enable carbon capture and sequestration (CCS). In addition, as policymakers consider options to reduce CO_2 emissions, provide an effective global framework for carbon management, including establishment of a transparent, predictable, economy-wide cost for CO_2 emissions.

All five strategies must be addressed together, global cooperation is required, and we must begin now and plan sustained commitment.

With that background, let me know turn to carbon capture and sequestration (CCS) underground which can facilitate the continued use of fossil fuels in an increasingly carbon-constrained world. CCS is technically achievable today, and has been demonstrated at a project level and applied in enhanced oil recovery. However, carbon dioxide has not been injected at the scales (both volumes and time periods) that will be necessary in the future.

CARBON CAPTURE AND SEQUESTRATION

It is likely that the world is moving into an era in which carbon emissions will be constrained. Oil and natural gas contribute more than half the current, energy-related CO_2 emissions. In a carbon-constrained world, the use of oil, natural gas and coal will be affected by policy measures to reduce carbon emissions. Carbon management will involve combining several measures to reduce CO_2 emissions, including improvements in the efficiency of energy use and the use of alternatives to fossil fuels such as biofuels, solar, wind, and nuclear power. However, to meet the energy demands of the Nation, the United States will continue using fossil fuels, including coal, extensively over the next 50 years or more. To do so, and to extend the resource base to include unconventional hydrocarbons such as heavy oil, tar sands, and shale oil, it will be necessary, if carbon constraints are imposed, to capture and sequester a large fraction of the CO_2 produced by burning these fossil fuels.

Carbon capture and sequestration (CCS) entails trapping CO_2 at the site where it is generated and storing it for periods sufficiently long (several thousand years) to mitigate the effect CO_2 can have on the Earth's climate. I will only consider geological sequestration and won't discuss possible alternatives, such as deep-sea sequestration, which is fraught with environmental concerns and issues of public acceptance. Geological sequestration would target spent oil and natural gas reservoirs and deep saline formations.

The technologies required for effective CCS are, by and large, viable. Projects continue at Sleipner field, the Weyburn EOR project in Canada,[1] and the In Salah saline formation project in Algeria.[2] The hurdles to implementation are largely ones of integration at scale. Current possible scenarios of climate change predict that by 2056, the level of carbon to be mitigated could be 7 billion tons per year or more.[3] [4] Sequestering a billion tons of carbon each year would entail pumping about 80 million barrels per day of supercritical CO_2 into secure geological formations. This amounts to about a quarter of the volume of water currently pumped worldwide for secondary oil recovery. At the local level, sequestering CO_2 from a 1-gigawatt coal-fired power station would require pumping into the ground some 150,000 barrels per day of supercritical CO_2.[5] A power station of that size would generate electricity for about 700,000 typical American homes.

While the technologies for CCS are essentially available, in that capture and storage can be implemented now, extensive scope remains for improvement. In particular, the capture stage of CCS is key, and currently dominates the overall cost. Novel, lower-cost approaches to capture would have a significant effect on the implementation of CCS and would, in turn, greatly influence the usability of fossil fuels under carbon constraint. Other areas where continued research is important:

—Fundamentals of storage, such as long-term physiochemical changes in the storage reservoir;
—Characterization and risk assessment (faults, cap rocks, wells);
—Reservoir management for long term storage;
—Integration of fit-for-purpose measurement, monitoring and verification;
—Ability to inject CO_2 into formations; and

[1] Wilson M, Monea M. (Eds.), IEA GHG Weyburn CO_2 Monitoring & Storage Project Summary Report 2000–2004 (2004), 273 p.

[2] Riddiford, F, Wright, I, Espie, T, and Torqui, A: "Monitoring geological storage: In Salah Gas CO_2 Storage Project," GHGT–7, Vancouver (2004).

[3] Pacala and Socolow: "Stabilization Wedges: Solving the Climate Problem for the next 50 Years with Current Technology," Science 305 (13 Aug. 2004): 968.

[4] Third Assessment Report—Climate Change 2001, Intergovernmental Panel on Climate Change.

[5] Socolow R: "Can We Bury Global Warming," Scientific American (2005).

—Retention and leakage, such as leakage through wells.

It is also crucial at this stage to undertake an assessment of the total U.S. capacity for CO_2 sequestration. While it is reasonable to expect that the combined capacity of existing hydrocarbon reservoirs and deep saline formations is large, a detailed understanding of the regional distribution of capacity throughout the United States is critically important.

It is important to note that there is no experience available with full-process integration, e.g. a coupled, large-scale coal-fired power plant with CCS. Several projects world-wide, most notably FutureGen in the United States and Zero-Gen in Australia, are in the process of designing and constructing an integrated large-scale power and CCS operation. Operating such facilities successfully is central to understanding the true economics and practical requirements for large-scale CCS.

One activity in which CO_2 is pumped into reservoirs currently is enhanced oil recovery (EOR). This provides a proving ground for various techniques that are relevant to CCS, and can be implemented while other carbon-management solutions are under development. At present, CO_2–EOR is not directed towards effective storage of CO_2 but the techniques can be modified to improve carbon sequestration.

A recent study completed by Kuuskraa[6] for the DOE suggests that application of advanced EOR techniques can increase U.S. recoverable oil resources. A total of 10 domestic oil basins and areas have now been assessed. These assessments indicate that the technically recoverable oil resource from application of "state-of-the-art" CO_2–EOR is 89 billion barrels. In addition, new work on the transition/residual oil zone resource documents the presence of 42 billion barrels of this category of oil in place in just 3 domestic oil basins (Permian, Big Horn, and Williston). Detailed reservoir simulation assessment shows that about 20 billion barrels of this oil in place could become technically recoverable by applying CO_2–EOR. Finally, an in-depth look at the additional oil recovery from applying "next generation" CO_2–EOR technology found further potential. This work shows that combining: (1) advanced, high reservoir contact well designs; (2) mobility and miscibility enhancement; (3) large volumes of CO_2 injection; and (4) real-time performance feedback and process control technology could bring about "game changer" levels of improvement in oil recovery efficiency.

Government incentives for CO_2 storage in association with CO_2–EOR, and new arrangements for developing suitable infrastructure for commercial use of anthropogenic CO_2 for EOR with storage, could help CO_2–EOR for storage succeed, particularly as CO_2 becomes increasingly available (and increasingly cheap) under a wide-scale adoption of CCS.

There is now a scientific consensus that anthropogenic CO_2 is driving detrimental climate change.[7] Moreover, the Intergovernmental Panel on Climate Change (IPCC) Special Report on CCS indicates that including it in a mitigation portfolio could help stabilize CO_2 concentrations in the atmosphere (at double the pre-industrial level) with a cost reduction of 30 percent or more, compared to other approaches.[8] More recently, the UK's Stern Review estimated that the cost of meaningful mitigation—maintaining atmospheric levels of CO_2 at no more than double the pre-industrial levels—would amount to about 1 percent of global GDP.[9] Doing nothing, on the other hand, would likely incur a greater cost. These studies indicate that the financial risk to the Nation of delaying action is now so high that a concerted emphasis on CCS is already strongly warranted.

Summary—Technical Issues

Tables T–V.1, T–V.2, and T–V.3 describe the basis for experience relevant to commercial CCS, current technologies in priority order, and future technologies in time/priority order, with time scales to commercial use.

Technology today is well-understood and effective and can probably deliver what is needed. However, there are some outstanding technical issues:

—Novel, lower cost capture technologies;

—Integration and fit-for-purpose deployment of monitoring and verification;

—Well leakage characterization and mitigation;

—Protocols for site characterization; and

—Technical basis for operational protocols and risk characterization.

[6] Kuuskraa VA: "Undeveloped Domestic Oil Resources: The foundation for Increasing Oil Production and a Viable Domestic Oil Industry"

[7] Oreskes, N: "The Scientific Consensus on Climate Change," Science 306 (3 Dec. 2004): 1686.

[8] "IPCC Special Report on Carbon Dioxide Capture and Storage," Intergovernmental Panel on Climate Change, Interlachen (2005), available at http://www.ipcc.ch/.

[9] "The Stern Review of the Economics of Climate Change," available at http://www.hmtreasury.gov.uk/independent__reviews/stern__review__economics__climate__change/stern__review__report.cfm.

TABLE T–V.1.—BASIS FOR EXPERIENCE RELEVANT TO COMMERCIAL CCS

Experience Basis	Significance	Limitations
CO_2 enhanced oil recovery (EOR)	> 30 years experience; injection >>1 M tons CO_2/year.	Very limited monitoring programs; questions of applicability of experience to saline formations.
Acid gas injection	> 15 years experience injecting CO_2 and H_2S into over 44 geologic formations.	Generally small volumes; very little publicly available technical information.
Hazardous waste disposal/underground injection control.		Most hazardous waste is not buoyant or reactive.
Natural gas storage	~100 years experience injecting natural gas into rocks.	Limited monitoring; different chemistry; built for temporary storage.
Natural analogs	Several large (> 50 trillion cubic feet) carbo-gaseous accumulations globally; proof of concept.	Most at steady state, transient knowledge unavailable; limited geography and geology.
Conventional oil and gas E&P	Nearly 150 years of technology and experience in predicting and managing buoyant fluids in crust.	Hydrocarbon recovery has goals and needs which differ from those of carbon sequestration.
Capture/gas separations technology	> 70 years separating CO_2 and other acid gases from gas streams, including at power plants.	Costs still higher than preferred under widespread deployment; still no integration of large power plants with CCS.
Large CO_2 storage projects	3 large-scale projects; > 6 pending before 2010.	Still limited monitoring program; limited geologic representation.
CO_2 pipelines and transportation	> 30 years experience at large scale; existing regulations likely to apply.	None.

TABLE T–V.2.—SUMMARY OF CCS TECHNOLOGIES IN PRIORITY ORDER

Technology	Significance	Brief Discussion
CO_2–EOR	Natural arena for exploring CCS	Provides a direct commercial incentive to pumping CO_2 into a reservoir.
Evaluation of CCS in association with coal-fired plant.	Development of integration of required technologies.	Projects in USA, Australia and China to develop CCS with coal plant.
Improved capture technologies	Key determinant of cost of CCS	Significant efforts in USA, Europe and Japan to drive down cost of capture.
Injection of CO_2 into subsurface formations.	Demonstration of injection and test of storage.	CO_2 currently injected at the Mt/yr level.
Development of models for migration of CO_2 subsurface.	Understanding of migration behavior underpins characterization and MMV.	Combination of modeling and experiment (e.g. Sleipner) to establish CO_2 migration.
Reservoir characterization for storage	Reservoir characterization techniques migrate to CO_2 storage estimates.	Available techniques tested at several sites.
Measurement, monitoring and verification (MMV).	Available MMV technologies applied to CO_2 injection and storage.	Available techniques tested at several sites.
Development of CO_2 resistant cements.	Primary leakage path is likely to be existing wells.	Improvements in resistance of cements to corrosion are currently being pursued.

TABLE T–V.3.—SUMMARY OF CCS TECHNOLOGIES IN TIME/PRIORITY ORDER, WITH TIMEFRAME TO COMMERCIAL USE

Technology	Significance	Timeframe
Extensive CO_2–EOR with substantial CO_2 sequestration.	Enhanced security of supply through better recovery	2010
Measurement, monitoring and verification (MMV) techniques.	Necessary prerequisite for implementation	2010
Site characterization and risk assessment	Determination of site suitability for sequestration	2010
CO_2 leak remediation technology	Necessary for implementation of CO_2 storage	2010
Demonstration of coal-fired power with CCS	Establish precedent for the technology	2010
Assessment of U.S. CO_2 sequestration capacity	Primary requirement for siting power stations	< 2020

TABLE T–V.3.—SUMMARY OF CCS TECHNOLOGIES IN TIME/PRIORITY ORDER, WITH TIMEFRAME TO COMMERCIAL USE—Continued

Technology	Significance	Time-frame
Novel, inexpensive capture technology	Key cost determinant of CCS	< 2020
Next-generation CO_2–EOR with maximum CO_2 storage	Increases usable CO_2 storage capacity in structurally confined geologic settings by three- to ten-fold.	2020
Ubiquitous coal-fired power with CCS	Extensive power generation without CO_2 emissions	2020
Rig-site or sub-surface hydrocarbon processing to generate low-carbon fuels or feedstocks and recycle CO_2 within the reservoir or field for EOR followed by CCS.	Keeps most of the carbon in or near the reservoir, simplifying CCS logistics and costs, enabling low carbon fuels/heat/power from oil and gas.	2030

Summary—Nontechnical Issues

Given the scope of commercial CCS, there are many issues that are not technical, per se, but relate to technical readiness and ways to maximize early investment:

—There is a high likelihood of a critical gap in human capital. Currently, workers who can execute CCS are the same as those employed in oil and natural gas exploration and production. In a carbon-constrained economy, there will not be enough skilled workers to go around. This is particularly true for geoscientists, but also true for chemical and mechanical engineers.

—Development of a comprehensive set of energy policies and strategies is critical to provide certainty to make investment decisions.

—The legislative and regulatory framework within which CCS is conducted will have a major impact on how rapidly the technology is implemented and ultimately will determine whether CCS can effectively mitigate carbon emissions and provide access to future hydrocarbon supplies.

—It is not clear that the science and technology programs in place today will provide answers required by regulators and decision makers. Greater dialogue between individuals working with technology and those developing a regulatory framework would help to reduce unnecessary regulation and guide R&D goals toward the most immediate needs.

—Infrastructure to transport CO_2, such as pipelines, is essential for commercial deployment. However, there is concern that pipelines for early project opportunities will not be able to carry additional future projects. Incentives and government action for this infrastructure can help to build networks sufficient to support large-scale, commercial CCS deployment in the United States.

CONCLUSIONS

The challenges facing our energy future are daunting, but not insurmountable. Given the massive scale of the global energy system and the long lead times necessary to make significant changes, concerted actions are needed now to promote U.S. competitiveness by balancing economic, security, and environmental goals. Carbon dioxide emissions are by their very nature a global issue, and atmospheric concentrations respect no geographic boundary, as such, ultimately a global solution is required. Carbon capture and storage is in some ways a unique opportunity for the United States to both develop technology and demonstrate leadership. We have large remaining fossil fuel reserves which could be economically and environmentally converted using carbon capture technology and we have the infrastructure and sedimentary basins to sequester the CO_2. The regulatory and legislative framework within which CCS is conducted will have a major impact on how rapidly the technology is implemented. The oil and gas industry has the skill sets to further develop and deploy this technology, but clearly cross industry and government cooperation is required. Thank you and I would be happy to answer any questions.

Senator DORGAN. Mr. Nelson, thank you very much. Finally, we will hear from Jeffrey Phillips, who represents the Electric Power Research Institute in North Carolina.

STATEMENT OF JEFFREY N. PHILLIPS, PROGRAM MANAGER, ELECTRIC POWER RESEARCH INSTITUTE

Mr. PHILLIPS. First of all, Mr. Chairman, I want to thank you for inviting me to speak on behalf of our Institute.

As you know, I testified in front of the Senate Energy Committee on the topic of advanced coal-generation technology earlier this month, and at that time I made five points. Today's coal power plants are much cleaner and more efficient than the existing fleet. Today's CO_2 capture technology will increase wholesale electricity prices by up to 80 percent, but we've identified a clear technology development path that can greatly decrease the cost impact by 2025. Unfortunately, the funding for that development path is sadly inadequate. And, finally, we engineers need some legal experts to help us set out the rules for deep geologic storage of CO_2.

At this hearing I would like to expand on the technology development path that we've identified to decrease the cost of CO_2 capture, as well as discuss the possibility of using the sale of captured CO_2 for enhanced oil recovery as a means to accelerate deployment of carbon capture technology and coal power plants worldwide.

In late 2004 EPRI initiated a new program called CoalFleet for Tomorrow, which is an industry-led effort aimed at accelerating the deployment of advanced coal power plant technology, particularly technology which can capture CO_2. In less than 3 years CoalFleet has made significant progress, including the creation of what we call research development and demonstration (RD&D) augmentation plans for both combustion-based and IGCC power plants. The main goal of these plants is to have cost-effective carbon capture storage technology ready and proven at commercial scale in the 2025 time frame. These plants identify the key actions that must take place that are not currently funded. More details of our RD&D augmentation plans can be found in my written testimony.

We're also looking at coal drying and methods for mitigating the impact of high altitudes, as well as ways to decrease water use, all important aspects for the use of North Dakota lignite.

CoalFleet is funded by more than 60 organizations, including power generators, equipment suppliers, oil companies, and government agencies, as well as coal and railroad companies. It provides a forum for all the key players in this field to discuss the issues and work together on RD&D to prove carbon capture and storage economics.

I want to take this moment to publicly thank Great River Energy for its strong support of CoalFleet, and we would welcome the participation of other power generation and coal-related organizations from North Dakota, as well as the other 49 States.

EPRI is already putting together action plans to implement demonstration projects in the CoalFleet RD&D plants. However, these projects will require significant amounts of money in order to move forward. One way to offset the cost of these demonstration projects would be to sell captured CO_2 to the oil industry for enhanced oil recovery.

Recent studies by the U.S. Department of Energy reveal the potential market for up to 17.5 billion tons of CO_2 for enhanced oil recovery. In theory at least this is enough CO_2—this CO_2 could be provided by 180 coal powerplants, each 500 megawatts, capturing 90 percent of their CO_2 over a 30-year period. That's a lot of new coal powerplants. Now, it's as much as the U.S. Department of Energy's energy information predicts will be built between now and 2025. And the thing that I find most amazing is if we did this, we would double domestic oil production. I repeat we would double domestic oil production. Of course, not all the new coal powerplants are going to be in areas where the oil industry needs CO_2, but some are, and even if we could just get 10 percent of these plants built with CO_2 capture that would give us 18 opportunities to build large-scale CO_2 capture facilities. And the history of other powerplant technologies tells us that the 18th facility will cost a lot less than the first one, which means that if we and the rest of the world have to build CO_2 capture facilities on all new coal powerplants, they will cost a lot less than they would if we miss this win-win opportunity.

I must point out even if oil companies were willing to pay $15 to $25 per ton for CO_2, that would not cover the full cost of capturing CO_2 from a coal power plant with today's technology, whether it's IGCC or oxy-firing. Consequently, we will have to come up with some way to subsidize the cost of capturing CO_2 in order to make it attractive.

Our CoalFleet program has also identified other non-technology-related impediments to deploying coal power based EOR projects, which I would be happy to discuss further during the question and answer period, as well as any other questions you have.

PREPARED STATEMENT

Finally, let me point out, if we develop and demonstrate carbon capture and storage here in the United States, the technology will be applied—could be applied worldwide, thereby providing additional leverage for R&D funds, creating international markets for U.S. technology and having a significant impact on global warming. That concludes my testimony.

[The statement follows:]

PREPARED STATEMENT OF JEFFREY N. PHILLIPS, PH.D.

Introduction

I am Jeff Phillips, Program Manager for Advanced Coal Generation for the Electric Power Research Institute (EPRI). EPRI is a non-profit, collaborative R&D organization with principal offices in Palo Alto, California; Knoxville, Tennessee; and Charlotte, North Carolina, where I work. EPRI appreciates the opportunity to provide testimony to the subcommittee on the topic of coal research, development, and demonstration (RD&D) as well as the potential benefits if the coal, oil, and gas industries were to work together to sequester carbon and enhance domestic oil production.

The key points I will make today include:

—Advanced coal power plant technologies with integrated CO_2 capture and storage (CCS) will be crucial to lowering U.S. electric power sector CO_2 emissions to 1990 levels by 2030. They will also be crucial to substantially lowering world CO_2 emissions as well.

—Without advanced coal power and integrated CCS technologies, the cost of electric power will increase dramatically, and the impact on the U.S. economy could reach $1 trillion per year by 2030.

—EPRI's CoalFleet for Tomorrow® program has identified the RD&D pathways to demonstrate, by 2025, a full portfolio of economically attractive, commercial-scale advanced coal power and integrated CCS technologies suitable for use with the broad range of U.S. coal types.

—The identified RD&D will cost $8 billion between now and 2017 and $17 billion cumulatively by 2025, and we need to begin immediately to ensure that these climate change solution technologies will be fully tested at scale by 2025.

—Selling CO_2 captured from coal power plants for EOR could lower the cost of testing CO_2 capture technology and would have the added benefit of increasing U.S. oil production.

—The U.S. Department of Energy has identified a potential EOR market for up to $17.5 billion tons of CO_2, which is equal to the 30-year cumulative CO_2 production of 180 coal power plants sized at 500 MW; however, a number of potential barriers need to be addressed before any such plants could become a reality, including regulatory and long-term liability issues.

SUMMARY OF KEY POINTS

Coal is the energy source for half of the electricity generated in the United States. Even with the aggressive development and deployment of alternative energy sources, numerous forecasts of energy use predict that coal will continue to provide a major share of our electric power generation throughout the 21st century. Coal is a stably priced, affordable, domestic fuel that can be used in an environmentally responsible manner. Criteria air pollutants from all types of new coal power plants have been reduced by more than 90 percent compared with plants built 40 years ago. Through the development and deployment of advanced coal plants with integrated CO_2 capture and storage (CCS) technologies, coal power will become part of the solution to satisfying both our energy needs and our global climate change concerns. However, a sustained RD&D program at heightened levels of investment and resolution of legal and regulatory unknowns for long-term geologic CO_2 storage will be required to achieve the promise of clean coal technologies. The members of EPRI's CoalFleet for Tomorrow® program—a research collaborative comprising more than 60 organizations representing international power generators, equipment suppliers, government research organizations, coal and oil companies, and a railroad—see crucial roles for both industry and governments worldwide in aggressively pursuing collaborative RD&D over the next 20+ years to create a full portfolio of commercially self-sustaining, competitive advanced coal power generation and CO_2 capture and storage technologies.

The potential return on this investment is enormous. EPRI's "Electricity Technology in a Carbon-Constrained Future" study suggests that it is technically feasible to reduce U.S. electric sector CO_2 emissions over the next 25 years while meeting the increased demand for electricity. The study showed that the largest single contributor to emissions reduction would come from the integration of CCS technologies to advanced coal-based power plants coming on-line after 2020. Economic analyses of scenarios to achieve the study's emission reduction goals show that a 2030 U.S. energy mix including advanced coal technologies with integrated CCS results in electricity at half the cost of a 2030 energy mix without advanced coal with CCS. In the case with advanced coal with CCS, the U.S. economy is $1 trillion per year larger than in the case without advanced coal and CCS, with a much stronger manufacturing sector. A previous EPRI economic study based on financial market "options" principles found a similarly large benefit to U.S. consumers of having coal's price-stabilizing influence on the electricity system.

The portfolio aspect of advanced coal with integrated CCS technologies must be emphasized because no single advanced coal technology (or any generating technology) has clear-cut economic advantages across the range of U.S. applications. The best strategy for meeting future electricity needs while addressing climate change concerns and minimizing economic disruption lies in developing a full portfolio of technologies from which power producers (and their regulators) can choose the option best suited to local conditions and preferences and provide power at the lowest cost to the customer. When it comes to advanced coal with integrated CCS technologies, there is no "silver bullet," but we can develop "silver buckshot."

Toward this end, four major technology efforts related to CO_2 emissions reduction from coal-based power systems must be undertaken:

—Increased efficiency and reliability of integrated gasification combined cycle (IGCC) power plants;
—Increased thermodynamic efficiency of pulverized-coal (PC) power plants;
—Improved technologies for capture of CO_2 from coal combustion- and gasification-based power plants; and
—Reliable, acceptable technologies for long-term storage of captured CO_2.

Identification of mechanisms to share RD&D financial and technical risks and to address legal and regulatory uncertainties must take place as well.

In short, a comprehensive recognition of all the factors needed to hasten deployment of competitive, commercial advanced coal and integrated CO_2 capture and storage technologies—and implementation of realistic, pragmatic plans to overcome barriers—is the key to meeting the challenge to supply affordable, environmentally responsible energy in a carbon-constrained world.

ACCELERATING RD&D ON ADVANCED COAL TECHNOLOGIES WITH CO_2 CAPTURE AND STORAGE—INVESTMENT AND TIME REQUIREMENTS

A typical path to develop a technology to commercial maturity consists of moving from the conceptual stage to laboratory testing, to small pilot-scale tests, to larger-scale tests, to multiple full-scale demonstrations, and finally to deployment in full-scale commercial operations. For capital-intensive technologies such as advanced coal power systems, each stage can take years or even decades to complete and each sequential stage tends to entail increasing levels of investment. As depicted in Figure 1, several key advanced coal power and CCS technologies are now in (or approaching) an "adolescent" stage of development. This is a time of particular vulnerability in the technology development cycle, as it is common for the expected costs of full-scale application to be higher than earlier estimates when less was known about scale-up and application challenges. Public agency and private funders can become disillusioned with a technology development effort at this point, but as long as fundamental technology performance results continue to meet expectations, and a path to cost reduction is clear, perseverance by project sponsors in maintaining momentum is crucial.

Unexpectedly high costs at the mid-stage of technology development have historically come down following market introduction, experience gained from "learning-by-doing," realization of economies of scale in design and production as order volumes rise, and removal of contingencies covering uncertainties and first-of-a-kind costs. An International Energy Agency study led by Carnegie Mellon University observed this pattern in the cost-over-time of power plant environmental controls and has predicted a similar reduction in the cost of power plant CO_2 capture technologies as the cumulative installed capacity grows.[1] EPRI concurs with their expectations of experience-based cost reductions and believes that RD&D on specifically identified technology refinements can lead to greater cost reductions sooner in the deployment phase.

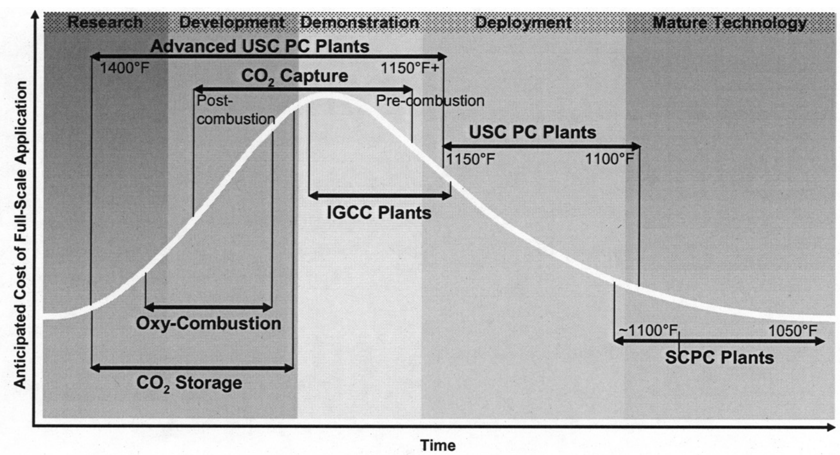


Figure 1 – Model of the development status of major advanced coal and CO_2 capture and storage technologies (temperatures shown for pulverized coal technologies are turbine inlet steam temperatures)

Of the coal-based power generating and carbon sequestration technologies shown in Figure 1, only supercritical pulverized coal (SCPC) technology has reached commercial maturity. It is crucial that other technologies in the portfolio—namely ultra-supercritical (USC) PC, integrated gasification combined cycle (IGCC), CO_2 capture (pre-combustion, post-combustion, and oxy-combustion), and CO_2 storage—be given sufficient support to reach the stage of declining constant dollar costs before society's requirements for greenhouse gas reductions compel their application in large numbers.

Figure 2 depicts the major activities in each of the four technology areas that must take place to achieve a set of robust solutions to reduce CO_2 emissions from coal power systems. This framework should be considered as a whole rather than as a set of discrete tasks. Although individual goals related to efficiency, CO_2 capture, and CO_2 storage present major challenges, significant challenges also arise

[1] IEA Greenhouse Gas R&D Programme (IEA GHG), "Estimating Future Trends in the Cost of CO_2 Capture Technologies," 2006/5, January 2006.

from complex interactions that occur when CO_2 capture processes are integrated with gasification- and combustion-based power plant processes.

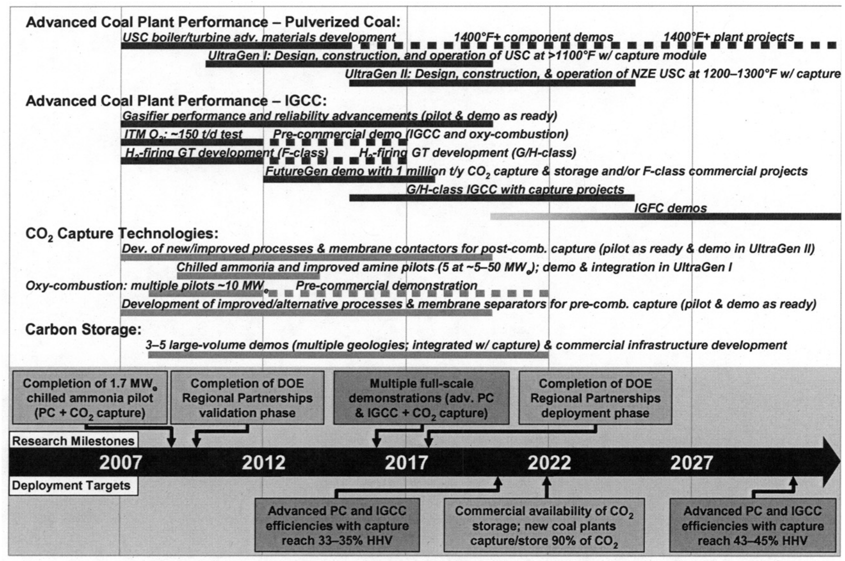


Figure 2 – Timing of advanced coal power system and CO_2 capture and storage RD&D activities and milestones

REDUCING CO_2 EMISSIONS THROUGH IMPROVED COAL POWER PLANT EFFICIENCY

Improved thermodynamic efficiency reduces CO_2 emissions by reducing the amount of fuel required to generate a given amount of electricity. A two-percentage point gain in efficiency provides a reduction in fuel consumption of roughly 5 percent and a similar reduction in CO_2 output. Depending on the technology used, improved efficiency can also provide similar reductions in criteria air pollutants, hazardous air pollutants, and water consumption.

A "typical" 500 MW (net) coal plant emits about 3 million metric tons of CO_2 per year. The annual power output and emissions of the current U.S. coal fleet are roughly equivalent to 600 such plants. The contributions attributable to individual plants vary considerably with differences in plant steam cycle, coal type, capacity factor, and operating regimes. For a given fuel, a new supercritical PC unit built today might produce 5–10 percent less CO_2 per megawatt-hour (MWh) than the existing fleet average for that coal type.

With an aggressive RD&D program on efficiency improvement, new ultra-supercritical (USC PC) plants could reduce CO_2 emissions per MWh by up to 25 percent relative to the existing fleet average. Significant efficiency gains are also possible for IGCC plants by employing advanced gas turbines and through more energy-efficient oxygen plants and synthesis (fuel) gas cleanup technologies.

EPRI and the Coal Utilization Research Council (CURC), in consultation with DOE, have identified a challenging but achievable set of milestones for improvements in the efficiency, cost, and emissions of PC and coal-based IGCC plants. The EPRI–CURC Roadmap projects an overall improvement in the thermal efficiency of state-of-the-art generating technology from 38–41 percent in 2010 to 44–49 percent by 2025 (on a higher heating value [HHV] basis; see Table 1). The ranges in the numbers are not simply a reflection of uncertainty, but rather they underscore an important point about differences among U.S. coals. The natural variations in moisture and ash content and combustion characteristics between coals have a significant impact on attainable efficiency.

An advanced coal plant firing North Dakota lignite, for example, would likely have an HHV efficiency two percentage points lower than the efficiency of a comparable plant firing subbituminous coal from Wyoming and Montana's Powder River basin. Similarly, plants using Powder River Basin coal would have efficiencies about two percentage points lower than plants firing Appalachian bituminous coals. Any government incentive program with an efficiency-based qualification criterion should recognize these inherent differences in the attainable efficiencies for plants using different ranks of coal.

As Table 1 indicates, technology-based efficiency gains over time will be offset by the energy required for CO_2 capture. Nevertheless, aggressive pursuit of the EPRI–CURC RD&D program offers the prospect of coal plants with CO_2 capture in 2025 that have net efficiencies meeting or exceeding current-day power plants without CO_2 capture.

TABLE 1.—EFFICIENCY MILESTONES IN EPRI–CURC ROADMAP

	2010	2015	2020	2025
PC & IGCC Systems (Without CO_2 Capture)	38–41 percent HHV	39–43 percent HHV	42–46 percent HHV	44–49 percent HHV
PC & IGCC Systems (With CO_2 Capture [1])	31–32 percent HHV	31–35 percent HHV	33–39 percent HHV	39–46 percent HHV

[1] Efficiency values reflect impact of 90 percent CO_2 capture, but not compression or transportation.

NEW PLANT EFFICIENCY IMPROVEMENTS—IGCC

Although IGCC is not yet a mature technology for coal-fired power plants, chemical plants around the world have accumulated a 100-year experience base operating coal-based gasification units and related gas cleanup processes. The most advanced of these units are similar to the front end of a modern IGCC facility. Similarly, several decades of experience firing natural gas and petroleum distillate have established a high level of maturity for the basic combined cycle generating technology. Nonetheless, ongoing RD&D continues to provide significant advances in the base technologies, as well as in the suite of technologies used to integrate them into an IGCC generating facility.

Efficiency gains in currently proposed IGCC plants will come from the use of new “FB-class” gas turbines, which will provide an overall plant efficiency gain of about 0.6 percentage point (relative to IGCC units with FA-class models, such as Tampa Electric’s Polk Power Station). This corresponds to a decrease in CO_2 emissions rate of about 1.5 percent.

Figure 3 depicts the anticipated timeframe for further developments identified by EPRI’s CoalFleet for Tomorrow® program that promise a succession of significant improvements in IGCC unit efficiency. Key technology advances under development include:

—larger capacity gasifiers (often via higher operating pressures that boost throughput without a commensurate increase in vessel size);
—integration of new gasifiers with larger, more efficient G- and H-class gas turbines;
—use of ion transport membrane (ITM) and/or other more energy-efficient technologies in oxygen plants;
—warm synthesis gas cleanup and membrane separation processes for CO_2 capture that reduce energy losses in these areas;
—recycle of liquefied CO_2 to replace water in gasifier feed slurry (reducing heat loss to water evaporation); and
—hybrid combined cycles using fuel cells to achieve generating efficiencies exceeding those of conventional combined cycle technology.

Improvements in gasifier reliability and in control systems also contribute to improved annual average efficiency by minimizing the number and duration of startups and shutdowns.

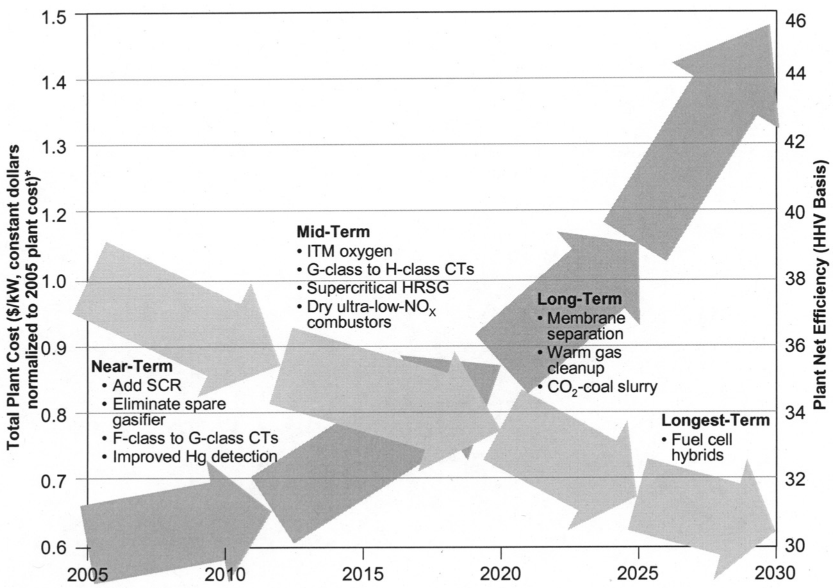


Figure 3 – RD&D path for capital cost reduction (falling arrows) and efficiency improvement (rising arrows) for IGCC power plants with 90% CO_2 capture

** For a slurry-fed gasifier designed for 90% unit availability and 90% pre-combustion CO_2 capture using Pittsburgh #8 bituminous coal; cost normalization using Chemical Engineering Plant Cost Index or equivalent. A similar trend is observed in analyses of dry-fed gasifiers using Power River Basin subbituminous coal, although the absolute values vary somewhat from those shown.*

Counteracting Gas Turbine Output Loss at High Elevations.—IGCC plants designed for application in the western Great Plains and Intermountain West must account for the natural reduction in gas turbine power output that occurs where the air is thin. This phenomenon is rooted in the fundamental volumetric flow limitation of a gas turbine, and can reduce power output by up to 15 percent at an elevation of 5,000 feet (relative to a comparable plant at sea level). EPRI is exploring measures to counteract this power loss, including inlet air chilling (a technique used at natural gas power plants to mitigate the power loss that comes from thinning of the air on a hot day) and use of supplemental burners between the gas turbine and steam turbine to boost the plant's steam turbine section generating capacity.

Larger, Higher Firing Temperature Gas Turbines.—For plants coming on-line around 2015, the larger size G-class gas turbines, which operate at higher firing temperatures (relative to F-class machines) can improve efficiency by 1 to 2 percentage points while also decreasing capital cost per kW capacity. The H-class gas turbines, coming on-line in the same timeframe, will provide a further increase in efficiency and capacity.

Ion Transport Membrane-Based Oxygen Plants.—Most gasifiers used in IGCC plants require a large quantity of high-pressure, high purity oxygen, which is typically generated on site with an expensive and energy-intensive cryogenic process. The ITM process allows the oxygen in high-temperature air to pass through a membrane while preventing passage of non-oxygen atoms. According to developers, an ITM-based oxygen plant consumes 35–60 percent less power and costs 35 percent less than a cryogenic plant. EPRI is performing a due diligence assessment of this technology in advance of potential participation in technology scale-up efforts.

Supercritical Heat Recovery Steam Generators.—In IGCC plants, hot exhaust gas exiting the gas turbine is ducted into a heat exchanger known as a heat recovery steam generator (HRSG) to transfer energy into water-filled tubes producing steam to drive a steam turbine. This combination of a gas turbine and steam turbine power cycles produces electricity more efficiently than either a gas turbine or steam turbine alone. As with conventional steam power plants, the efficiency of the steam cycle in a combined cycle plant increases when turbine inlet steam temperature and pressure are increased. The higher exhaust temperatures of G- and H-class gas turbines offer the potential for adoption of more-efficient supercritical steam cycles. Materials for use in a supercritical HRSG are generally established.

Synthesis Gas Cleaning at Higher Temperatures.—The acid gas recovery (AGR) processes currently used to remove sulfur compounds from synthesis gas require that the gas and solvent be cooled to about 100 °F, thereby causing a loss in efficiency. Further costs and efficiency loss are inherent in the process equipment and auxiliary steam required to recover the sulfur compounds from the solvent and convert them to useable products. Several DOE-sponsored RD&D efforts aim to reduce the energy losses and costs imposed by this recovery process. These technologies (described below) could be ready—with adequate RD&D support—by 2020:

—The Selective Catalytic Oxidation of Hydrogen Sulfide process eliminates the Claus and Tail Gas Treating units, along with the traditional solvent-based AGR contactor, regenerator, and heat exchangers, by directly converting hydrogen sulfide (H_2S) to elemental sulfur. The process allows for a higher operating temperature of approximately 300 °F, which eliminates part of the low-temperature gas cooling train. The anticipated benefit is a net capital cost reduction of about $60/kW along with an efficiency gain of about 0.8 percentage point.

—The RTI/Eastman High Temperature Desulfurization System uses a regenerable dry zinc oxide sorbent in a dual loop transport reactor system to convert H_2S and COS to H_2O, CO_2, and SO_2. Tests at Eastman Chemical Company have shown sulfur species removal rates above 99.9 percent, with 10 ppm output versus 8,000+ ppm input sulfur, using operating temperatures of 800–1,000 °F. This process is also being tested for its ability to provide a high-pressure CO_2 by-product. The anticipated benefit for IGCC, compared with using a standard oil-industry process for sulfur removal, is a net capital cost reduction of $60–$90 per kW, a thermal efficiency gain of 2–4 percent for the gasification process, and a slight reduction in operating cost. Tests are also under way for a multi-contaminant removal processes that can be integrated with the transport desulfurization system at temperatures above 480 °F.

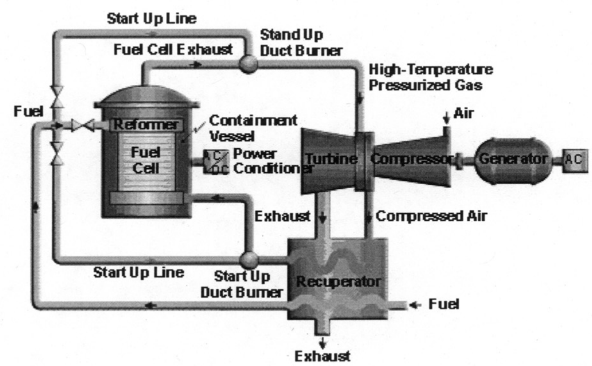
Liquid CO_2-Coal Slurrying for Gasification of Low-Rank Coals.—Future IGCC plants may recycle some of the recovered liquid CO_2 to replace water as the slurrying medium for the coal feed. This is expected to increase gasification efficiency for all coals, but particularly for subbituminous coal and lignite, which have naturally high moisture contents. The liquid CO_2 has a lower heat of vaporization than water and is able to carry more coal per unit mass of fluid. The liquid CO_2-coal slurry will flash almost immediately upon entering the gasifier, providing good dispersion of the coal particles and potentially yielding the higher performance of a dry-fed gasifier with the simplicity of a slurry-fed system.

Traditionally, slurry-fed gasification technologies have a cost advantage over conventional dry-fed fuel handling systems, but they suffer a large performance penalty when used with coals containing a large fraction of water and ash. EPRI identified CO_2 coal slurrying as an innovative fuel preparation concept 20 years ago, when IGCC technology was in its infancy. At that time, however, the cost of producing liquid CO_2 was too high to justify the improved thermodynamic performance.

To date, CO_2-coal slurrying has only been demonstrated at pilot scale and has yet to be assessed in feeding coal to a gasifier, so the estimated performance benefits remain to be confirmed. The concept warrants consideration for future IGCC plants that capture and compress CO_2 for storage, as this will substantially reduce the incremental cost of producing a liquid CO_2 stream. It will first be necessary, however, to update previous studies to quantify the potential benefit of liquid CO_2 slurries with IGCC plants designed for CO_2 capture. If the predicted benefit is economically advantageous, a significant amount of scale-up and demonstration work would be required to qualify this technology for commercial use.

Fuel Cells and IGCC.—No matter how far gasification and turbine technologies advance, IGCC power plant efficiency will never progress beyond the inherent thermodynamic limits of the gas turbine and steam turbine power cycles (along with lower limits imposed by available materials technology). Several IGCC-fuel cell hybrid power plant concepts (IGFC) aim to provide a path to coal-based power generation with net efficiencies that exceed those of conventional combined cycle generation.

Along with its high thermal efficiency, the fuel cell hybrid cycle reduces the energy consumption for CO_2 capture. The anode section of the fuel cell produces a stream that is highly concentrated in CO_2. After removal of water, this stream can be compressed for sequestration. The concentrated CO_2 stream is produced without having to include a water-gas shift reactor in the process (see Figure 4). This further improves the thermal efficiency and decreases capital cost. IGFC power systems are a long-term solution, however, and are unlikely to see full-scale demonstration until about 2030.



Source: U.S. Department of Energy; http://www.netl.doe.gov/technologies/coalpower/fuelcells/hybrids.html

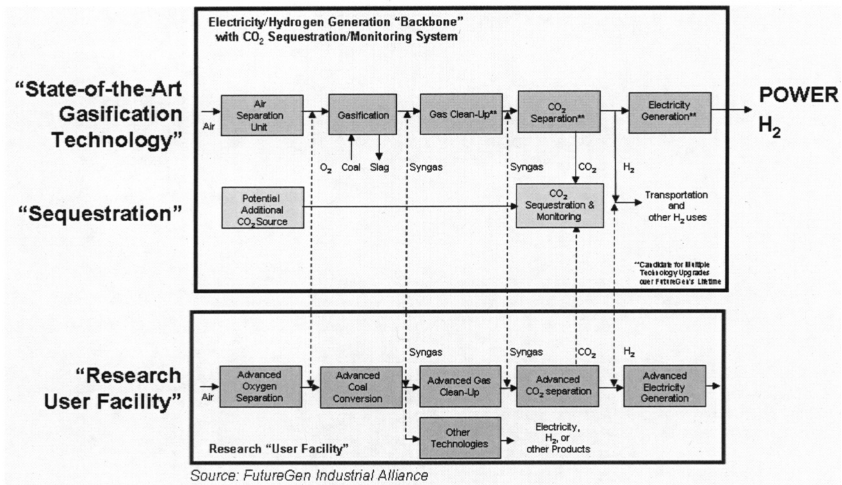
Figure 4 – Schematic of fuel cell-turbine hybrid

Role of FutureGen.—The FutureGen Industrial Alliance and DOE are building a first-of-its-kind, near-zero emissions coal-fed IGCC power plant integrated with CCS. The commencement of full-scale operations is targeted for 2013. The project aims to sequester CO_2 in a representative geologic formation at a rate of at least one million metric tons per year.

The FutureGen design will address scaling and integration issues for coal-based, zero emissions IGCC plants. In its role as a "living laboratory," FutureGen is designed to validate additional advanced technologies that offer the promise of clean environmental performance at a reduced cost and increased reliability. FutureGen will have the flexibility to conduct full-scale and slipstream tests of such scalable advanced technologies as:

—Membrane processes to replace cryogenic separation for oxygen production;
—An advanced transport reactor sidestream with 30 percent of the capacity of the main gasifier;
—Advanced membrane and solvent processes for H_2 and CO_2 separation;
—A raw gas shift reactor that reduces the upstream clean-up requirements;
—Ultra-low-NO_X combustors that can be used with high-hydrogen synthesis gas;
—A fuel cell hybrid combined cycle pilot;
—Challenging first-of-a-kind system integration; and
—Smart dynamic plant controls including a CO_2 management system.

Figure 5 provides a schematic of the "backbone" and "research platform" process trains envisioned for the FutureGen plant.



Source: FutureGen Industrial Alliance

Figure 5 – FutureGen technology platforms

Figure 6 summarizes EPRI's recommended major RD&D activities for improving the efficiency and cost of IGCC technologies with CO_2 capture.

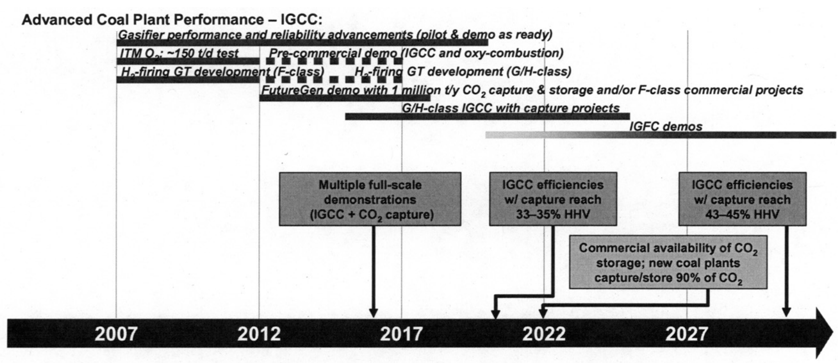


Figure 6 – Timing of advanced IGCC and CO_2 capture integration RD&D activities and milestones

NEW PLANT EFFICIENCY IMPROVEMENTS—ADVANCED PULVERIZED COAL

Pulverized-coal power plants have long been a primary source of reliable and affordable power in the United States and around the world. The advanced level of maturity of the technology, along with basic thermodynamic principles, suggests that significant efficiency gains can most readily be realized by increasing the operating temperatures and pressures of the steam cycle. Such increases, in turn, can be achieved only if there is adequate development of suitable materials and new boiler and steam turbine designs that allow use of higher steam temperatures and pressures.

Current state-of-the-art plants use supercritical main steam conditions (i.e., temperature and pressure above the "critical point" where the liquid and vapor phases of water are indistinguishable). SCPC plants typically have main steam conditions up to 1100 °F. The term "ultra-supercritical" is used to describe plants with main steam temperatures in excess of 1100 °F and potentially as high as 1400 °F.

Achieving higher steam temperatures and higher efficiency will require the development of new corrosion-resistant, high-temperature nickel alloys for use in the boiler and steam turbine. In the United States, these challenges are being addressed by the Ultra-Supercritical Materials Consortium, a DOE R&D program involving

Energy Industries of Ohio, EPRI, the Ohio Coal Development Office, and numerous equipment suppliers. EPRI provides technical management for the consortium. Results are applicable to all ranks of coal.

It is expected that a USC PC plant operating at about 1300 °F will be built during the next 7 to 10 years, following the demonstration and commercial availability of advanced materials from these programs. This plant would achieve an efficiency of about 43 percent (HHV) on subbituminous coal, compared with 37 percent for a current state-of-the-art plant, and would reduce CO_2 production per net MWh by about 15 percent.

Ultimately, nickel-base alloys are expected to enable stream temperatures in the neighborhood of 1400 °F and generating efficiencies up to 45 percent HHV with subbituminous coal. This approximately 10 percentage point improvement over the efficiency of a new subcritical pulverized-coal plant would equate to a decrease of about 25 percent in CO_2 and other emissions per MWh.

Figure 7 illustrates a timeline developed by EPRI's CoalFleet for Tomorrow® program to establish efficiency improvement and cost reduction goals for USC PC plants with CO_2 capture.

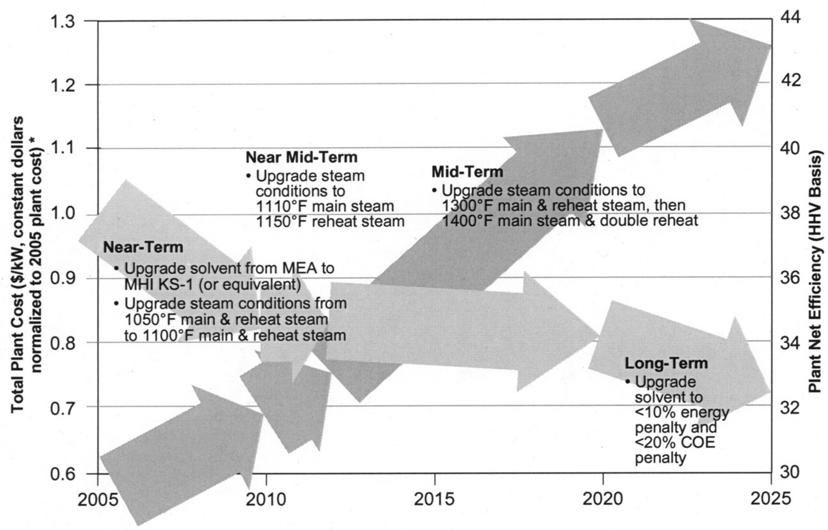


Figure 7 – RD&D path for capital cost reduction (falling arrows) and efficiency improvement (rising arrows) for PC power plants with 90% CO_2 capture

** For a unit designed for 90% unit availability and 90% post-combustion CO_2 capture firing a Pittsburgh #8 bituminous coal; cost normalization using Chemical Engineering Plant Cost Index or equivalent. A similar trend is observed in analyses of PC units using Power River Basin subbituminous coal and North Dakota lignite, although the efficiency values are up to two to four percentage points lower than those shown.*

UltraGen USC PC Commercial Projects.—EPRI and industry representatives have proposed a framework to support commercial projects that demonstrate advanced PC technologies. The vision entails construction of two commercially operated USC PC power plants that combine state-of-the-art pollution controls, ultra-supercritical steam power cycles, and innovative flue gas scrubbing technologies to capture CO_2.

The UltraGen I plant will use the best of today's proven ferritic steels, while UltraGen II will be the first plant in the United States to feature new, nickel-based alloys that are able to withstand the higher temperatures involved.

UltraGen I will feature an approximately quarter-scale CO_2 capture system demonstration using the best established technology. This system will be about 15 times the size of the largest system operating on a coal-fired boiler today. UltraGen II will double the size of the CO_2 capture system, and may demonstrate a new class of chemical solvent if one of the emerging low-energy processes has reached a sufficient stage of development. Both plants will demonstrate ultra-low emissions. Both UltraGen demonstration plants will dry and compress the captured CO_2 for long-term geologic storage and/or use in enhanced oil or gas recovery operations. Figure 8 depicts the proposed key features of UltraGen I and II.

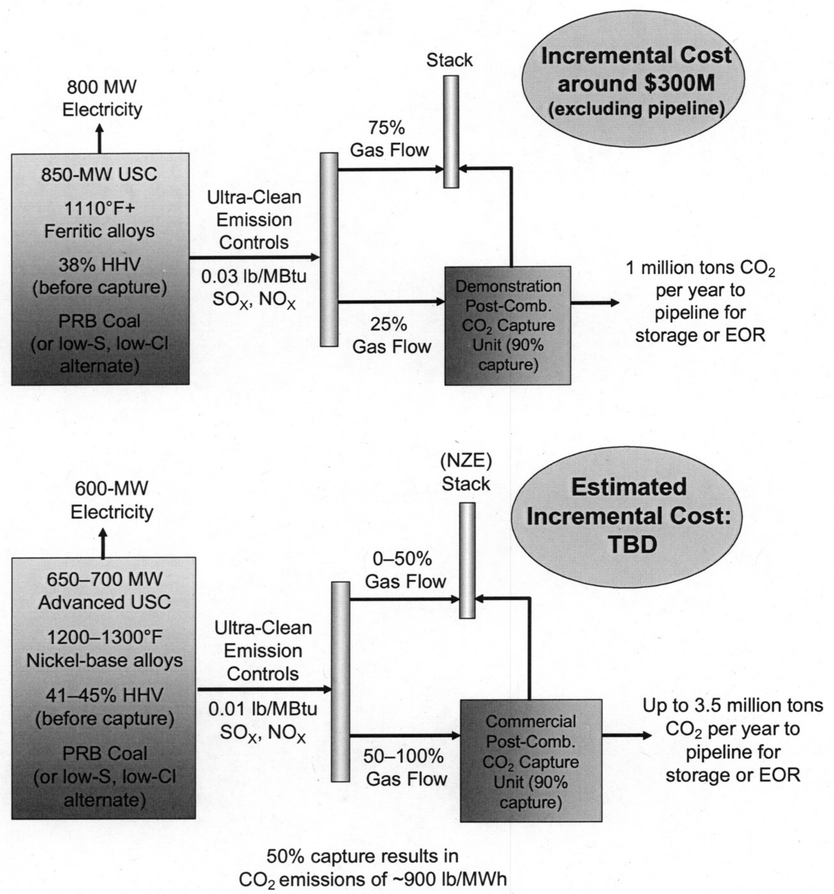


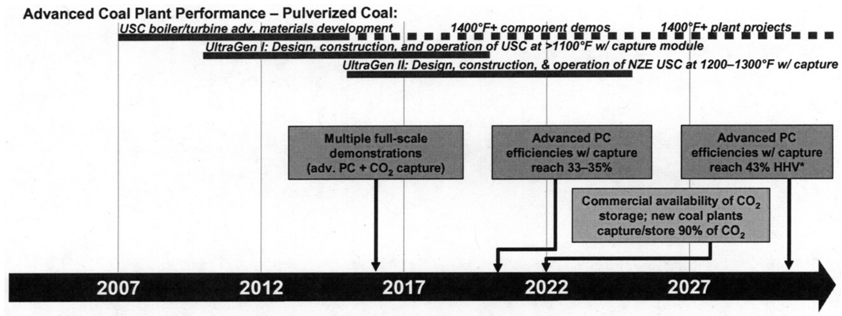
Figure 8 – Key parameters for UltraGen I (upper schematic) and UltraGen II (lower schematic), assuming a subbituminous feed coal

To provide a platform for testing and developing emerging PC technologies, the program will allow for technology trials at existing sites as well as at the sites of new projects. EPRI expects the UltraGen projects will be commercially operated units dispatching electricity to the grid. The differential cost to the host utility for demonstrating these improved features are envisioned to be offset by tax credits and funds raised by an industry-led consortia formed through EPRI.

The UltraGen projects represent the type of "giant step" collaborative efforts that need to be taken to advance PC technology to the next phase of evolution and assure competitiveness in a carbon-constrained world. Because of the time and expense for each "design and build" iteration for coal power plants (3 to 5 years not counting the permitting process and $2 billion), there is no room for hesitation in terms of commitment to advanced technology validation and demonstration projects.

The UltraGen projects will resolve critical barriers to the deployment of USC PC technology by providing a shared-risk vehicle for testing and validating high-temperature materials, components, and designs in plants also providing superior environmental performance.

Figure 9 summarizes EPRI's recommended major RD&D activities for improving the efficiency and cost of USC PC technologies with CO_2 capture.



*for bituminous coal; equally advanced PC plants firing subbituminous coal and lignite will have efficiencies two to four percentage points lower due to higher moisture and ash contents

Figure 9 – Timing of advanced PC and CO_2 capture integration RD&D activities and milestones

Efficiency Gains for the Existing PC Fleet.—Many subcritical units in the existing U.S. fleet will continue to operate for years to come. Replacing these units en masse would be economically prohibitive. Their flexibility for load following and provision of support services to ensure grid stability makes them highly valuable. With equipment upgrades, many of these units can realize modest efficiency gains, which, when accumulated across the existing generating fleet could make a sizeable difference.

These upgrades depend on the equipment configuration and operating parameters of a particular plant and may include:

—turbine blading and steam path upgrades;
—turbine control valve upgrades for more efficient regulation of steam;
—cooling tower and condenser upgrades to reduce circulating water temperature, steam turbine exhaust backpressure, and auxiliary power consumption;
—cooling tower heat transfer media upgrades;
—condenser optimization to maximize heat transfer and minimize condenser temperature;
—condenser air leakage prevention/detection;
—variable speed drive technology for pump and fan motors to reduce power consumption;
—air heater upgrades to increase heat recovery and reduce leakage;
—advanced control systems incorporating neural nets to optimize temperature, pressure, and flow rates of fuel, air, flue gas, steam, and water;
—optimization of water blowdown and blowdown energy recovery;
—optimization of attemperator design, control, and operating scenarios;
—sootblower optimization via "intelligent" sootblower system use; and
—coal drying (for plants using lignite and subbituminous coals).

Coal Drying for Increased Generating Efficiency.—Boilers designed for high-moisture North Dakota lignite have traditionally employed higher feed rates (lb/hr) to account for the large latent heat load to evaporate fuel moisture. An innovative concept developed by Great River Energy (GRE) and Lehigh University uses low-grade heat recovered from within the plant to dry incoming fuel to the boiler, thereby boosting plant efficiency and output. [In contrast, traditional thermal drying processes are complex and require high-grade heat to remove moisture from the coal.] Specifically, the GRE approach uses steam condenser and boiler exhaust heat exchangers to heat air and water fed a fluidized-bed coal dryer upstream of the plant pulverizers. Based on successful tests with a pilot-scale dryer and more than a year of continuous operation with a prototype dryer at its Coal Creek station, GRE (with U.S. Department of Energy support and EPRI technical consultation) is now building a full suite of dryers for Unit 2 (i.e., a commercial-scale demonstration). In addition to the efficiency benefits from reducing the lignite feed moisture content by about 25 percent, the plant's air emissions will be reduced as well.[2]

[2] C. Bullinger, M. Ness, and N. Sarunac, "One Year of Operating Experience with Prototype Fluidized Bed Coal Dryer at Coal Creek Generating Station," 32nd International Technical Conference on Coal Utilization and Fuel Systems, Clearwater FL, June 10–15, 2007.

IMPROVING CO_2 CAPTURE TECHNOLOGIES

The laws of physics and chemistry impose inherent limits on the extent of CO_2 reductions that can be achieved through efficiency gains alone. Further reductions in CO_2 emissions will require pre-combustion or post-combustion CO_2 capture technologies and the storage of separated CO_2 in locations where it can be kept away from the atmosphere for centuries or longer.

Albeit at considerable cost, CO_2 capture technologies can be integrated into all coal-based power plant technologies. For existing plants, specific plant design features, space limitations, and various economic and regulatory considerations will determine whether retrofit-for-capture is feasible. For both new plants and retrofits, there is a tremendous need (and opportunity) to reduce the energy required to remove CO_2 from fuel gas or flue gas. Figure 10 shows a selection of the key technology developments and test programs needed to achieve commercial CO_2 capture technologies for advanced coal combustion- and gasification-based power plants at a progressively shrinking constant-dollar levelized cost-of-electricity premium. Specifically, the target is a premium of about \$6/MWh in 2025 (relative to plants at that time without capture) compared with an estimated 2010 cost premium of perhaps \$40/MWh (not counting the cost of transportation and storage). Such a goal poses substantial engineering challenges and will require major investments in RD&D to reduce the currently large net power reductions and efficiency (operating cost) penalties associated with CO_2 capture technologies. Achieving this goal will allow power producers to meet the public demand for stable electricity prices while reducing CO_2 emissions to address climate change concerns.

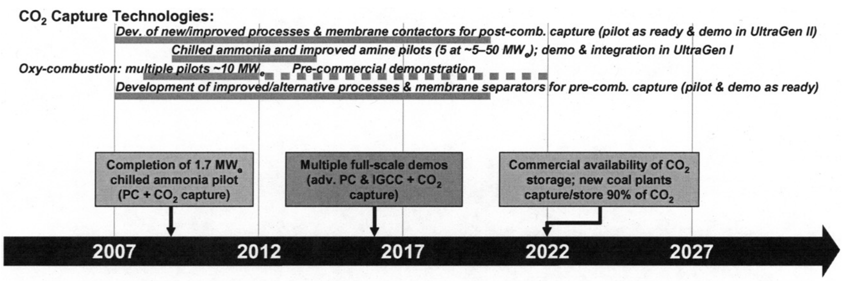


Figure 10 – Timing of CO_2 capture technology development RD&D activities and milestones

PRE-COMBUSTION CO_2 CAPTURE (IGCC)

IGCC technology allows for CO_2 capture to take place via an added fuel gas processing step at elevated pressure, rather than at the atmospheric pressure of post-combustion flue gas, permitting capital savings through smaller equipment sizes as well as lower operating costs.

Currently available technologies for such pre-combustion CO_2 removal use a chemical and/or physical solvent that selectively absorbs CO_2 and other "acid gases," such as hydrogen sulfide. Application of this technology requires that the CO in synthesis gas (the principal component) first be "shifted" to CO_2 and hydrogen via a catalytic reaction with water. The CO_2 in the shifted synthesis gas is then removed via contact with the solvent in an absorber column, leaving a hydrogen-rich synthesis gas for combustion in the gas turbine. The CO_2 is released from the solvent in a regeneration process that typically reduces pressure and/or increases temperature.

Chemical plants currently employ such a process commercially using methyl diethanolamine (MDEA) as a chemical solvent or the Selexol and Rectisol processes, which rely on physical solvents. Physical solvents are generally preferred when extremely high (>99.8 percent) sulfur species removal is required. Although the required scale-up for IGCC power plant applications is less than that needed for scale-up of post-combustion CO_2 capture processes for PC plants, considerable engineering challenges remain and work on optimal integration with IGCC cycle processes has just begun.

The impact of current pre-combustion CO_2 removal processes on IGCC plant thermal efficiency and capital cost is significant. In particular, the water-gas shift reaction reduces the heating value of synthesis gas fed to the gas turbine. Because the gasifier outlet ratios of CO to methane to H_2 are different for each gasifier technology, the relative impact of the water-gas shift reactor process also varies. In general, however, it can be on the order of a 10 percent fuel energy reduction. Heat regeneration of solvents further reduces the steam available for power generation. Other solvents, which are depressurized to release captured CO_2, must be re-pressurized for reuse. Cooling water consumption is increased for solvents needing cooling after regeneration and for pre-cooling and interstage cooling during compression of separated CO_2 to a supercritical state for transportation and storage. Heat integration with other IGCC cycle processes to minimize these energy impacts is complex and is currently the subject of considerable RD&D by EPRI and others.

Membrane CO_2 Separation.—Technology for separating CO_2 from shifted synthesis gas (or flue gas from PC plants) offers the promise of lower auxiliary power consumption but is currently only at the laboratory stage of development. Several organizations are pursuing different approaches to membrane-based applications. In general, however, CO_2 recovery on the low-pressure side of a selective membrane can take place at a higher pressure than is now possible with solvent processes, reducing the subsequent power demand for compressing CO_2 to a supercritical state. Membrane-based processes can also eliminate steam and power consumption for regenerating and pumping solvent, respectively, but they require power to create the pressure difference between the source gas and CO_2-rich sides. If membrane technology can be developed at scale to meet performance goals, it could enable up to a 50 percent reduction in capital cost and auxiliary power requirements relative to current CO_2 capture and compression technology.

POST-COMBUSTION CO_2 CAPTURE (PC AND CFB PLANTS)

The post-combustion CO_2 capture processes envisioned for power plant boilers draw upon commercial experience with amine solvent separation at much smaller scale in the food and beverage and chemical industries and upon three applications of CO_2 capture from a slipstream of exhaust gas from circulating fluidized-bed (CFB) units.

These processes contact flue gas with an amine solvent in an absorber column (much like a wet SO_2 scrubber) where the CO_2 chemically reacts with the solvent. The CO_2-rich liquid mixture then passes to a stripper column where it is heated to change the chemical equilibrium point, releasing the CO_2. The “regenerated” solvent is then recirculated back to the absorber column, while the released CO_2 may be further processed before compression to a supercritical state for efficient transportation to a storage location.

After drying, the CO_2 released from the regenerator is relatively pure. However, successful CO_2 removal requires very low levels of SO_2 and NO_2 entering the CO_2 absorber, as these species also react with the solvent. Thus, high-efficiency SO_2 and NO_X control systems are essential to minimizing solvent consumption costs for post-combustion CO_2 capture. Extensive RD&D is in progress to improve the solvent and system designs for power boiler applications and to develop better solvents with greater absorption capacity, less energy demand for regeneration, and greater ability to accommodate flue gas contaminants.

At present, monoethanolamine (MEA) is the “default” solvent for post-combustion CO_2 capture studies and small-scale field applications. Processes based on improved amines, such as Fluor’s Econamine FG Plus and Mitsubishi Heavy Industries’ KS–1, are under development. The potential for improving amine-based processes appears significant. For example, a recent study based on KS–1 suggests that its impact on net power output for a supercritical PC unit would be 19 percent and its impact on the levelized cost-of-electricity would be 44 percent, whereas earlier studies based on suboptimal MEA applications yielded output penalties approaching 30 percent and cost-of-electricity penalties of up to 65 percent.

Accordingly, amine-based engineered solvents are the subject of numerous ongoing efforts to improve performance in power boiler post-combustion capture applications. Along with modifications to the chemical properties of the sorbents, these efforts are addressing the physical structure of the absorber and regenerator equipment, examining membrane contactors and other modifications to improve gas-liquid contact and/or heat transfer, and optimizing thermal integration with steam turbine and balance-of-plant systems. Although the challenge is daunting, the payoff is potentially massive, as these solutions may be applicable not only to new plants, but to retrofits where sufficient plot space is available at the back end of the plant.

Finally, as discussed earlier, deploying USC PC technology to increase efficiency and lower uncontrolled CO_2 per MWh can further reduce the cost impact of post-combustion CO_2 capture.

Chilled Ammonia Process.—Post-combustion CO_2 capture using a chilled ammonia-based solvent offers the promise of dramatically reducing parasitic power losses relative to MEA. In the process currently under development and testing by Alstom and EPRI, respectively, CO_2 is absorbed in a solution of ammonium carbonate, at low temperature and atmospheric pressure, and combines with the $NaCO_3$ to form ammonium bicarbonate.

Compared with amines, ammonium carbonate has over twice the CO_2 absorption capacity and requires less than half the heat to regenerate. Further, regeneration can be performed under higher pressure than amines, so the released CO_2 is already partially pressurized. Therefore, less energy is subsequently required for compression to a supercritical state for transportation to an injection location. Developers have estimated that the parasitic power loss from a full-scale supercritical PC plant using chilled ammonia CO_2 capture could be as low as 10 percent, with an associated cost-of-electricity penalty of just 25 percent. Following successful experiments at 0.25 MWe scale, Alstom and a consortium of EPRI members are constructing a 1.7 MWe pilot unit to test the chilled ammonia process with a flue gas slipstream at We Energies' Pleasant Prairie Power Plant.

Other "multi-pollutant" control system developers are also exploring ammonia-based processes for CO_2 removal.

OXY-FUEL COMBUSTION BOILERS

Fuel combustion in a blend of oxygen and recycled flue gas rather than in air (known as oxy-fuel combustion or oxy-combustion) is gaining interest as a viable CO_2 capture alternative for PC and CFB plants. The process is applicable to virtually all fossil-fueled boiler types and is a candidate for retrofits as well as new power plants.

Firing coal with high-purity oxygen alone would result in too high of a flame temperature, which would increase slagging, fouling, and corrosion problems, so the oxygen is diluted by mixing it with a slipstream of recycled flue gas. As a result, the flue gas downstream of the recycle slipstream take-off consists primarily of CO_2 and water vapor (although it also contains small amounts of nitrogen, oxygen, and criteria pollutants). After the water is condensed, the CO_2-rich gas is compressed and purified to remove contaminants and prepare the CO_2 for transportation and storage.

Oxy-combustion boilers have been studied in laboratory-scale and small pilot units of up to 3 MWt. Two larger pilot units, at 10 MWe, are now under construction by Babcock & Wilcox (B&W) and Vattenfall. An Australian-Japanese project team is pursuing a 30 MWe repowering project in Australia. These larger tests will allow verification of mathematical models and provide engineering data useful for designing pre-commercial systems. The first such pre-commercial unit could be built at SaskPower's Shand station near Estevan, Saskatchewan. SaskPower, B&W Canada, and Air Liquide have been jointly developing an oxy-combustion SCPC design, and a decision on whether to proceed to construction is expected by late 2007, with a target in-service date of 2011–2012.

CO_2 TRANSPORT AND GEOLOGIC STORAGE

Application of CO_2 capture technologies implies that there will be secure and economical storage or beneficial uses that can assure CO_2 will be kept out of the atmosphere. Natural underground CO_2 reservoirs in Colorado, Utah, and other western states testify to the effectiveness of long-term geologic CO_2 storage. CO_2 is also found in natural gas reservoirs, where it has resided for millions of years. Thus, evidence suggests that similarly "capped" geologic formations will be ideal for storing CO_2 for millennia or longer.

The most developed approach for large-scale CO_2 storage is injection into depleted or partially depleted oil and gas reservoirs and similar geologically sealed "saline formations" (porous rocks filled with brine that is impractical for desalination). Partially depleted oil reservoirs provide the potential added benefit of enhanced oil recovery (EOR). [EOR is used in mature fields to recover additional oil after standard extraction methods have been used. When CO_2 is injected for EOR, it causes residual oil to swell and become less viscous, allowing some to flow to production wells, thus extending the field's productive life.] By providing a commercial market for CO_2 captured from industrial sources, EOR helps the economics of CCS projects, and in some cases can reduce regulatory and liability uncertainties. Although less developed than EOR, researchers are exploring the effectiveness of CO_2 injection for enhancing production from depleted natural gas fields (particularly in compartmentalized formations where pressure has dropped) and from deep methane-bearing coal seams. DOE and the International Energy Agency are among the sponsors of such efforts.

Geologic sequestration as a strategy for reducing CO_2 emissions to the atmosphere is currently being demonstrated in several projects around the world. Three larger-scale projects—Statoil's Sleipner Saline Aquifer CO_2 Storage project in the North Sea off of Norway; the Weyburn Project in Saskatchewan, Canada; and the In Salah Project in Algeria—together sequester about 3–4 million metric tons of CO_2 per year, which collectively approaches the output of just one typical 500 MW coal-fired power plant. With 17 collective operating years of experience, these projects have thus far demonstrated that CO_2 storage in deep geologic formations can be carried out safely and reliably. Statoil estimates that Norwegian greenhouse gas emissions would have risen incrementally by 3 percent if the CO_2 from the Sleipner project had been vented rather than sequestered.[3]

Table 2 lists a selection of current and planned CO_2 storage projects as of early 2007, including those involving EOR.

TABLE 2.—SELECT EXISTING AND PLANNED CO_2 STORAGE PROJECTS AS OF EARLY 2007

Project	CO_2 Source	Country	Start	Anticipated amount injected by		
				2006	2010	2015
Sleipner	Gas. Proc	Norway	1996	9 MT	13 MT	18 MT
Weyburn	Coal	Canada	2000	5 MT	12 MT	17 MT
In Salah	Gas. Proc.	Algeria	2004	2 MT	7 MT	12 MT
Snohvit	Gas. Proc.	Norway	2007		2 MT	5 MT
Gorgon	Gas. Proc.	Australia	2010			12 MT
DF–1 Miller	Gas	U.K.	2009		1 MT	8 MT
DF–2 Carson	Pet Coke	U.S.	2011			16 MT
Draugen	Gas	Norway	2012			7 MT
FutureGen	Coal	U.S.	2012			2 MT
Monash	Coal	Australia	NA			NA
SaskPower	Coal	Canada	NA			NA
Ketzin/CO_2 STORE	NA	Germany	2007		50 KT	50 KT
Otway	Natural	Australia	2007		100 KT	100 KT
TOTALS				16 MT	33 MT	99 MT

Source: Sally M. Benson, "Can CO_2 Capture and Storage in Deep Geological Formations Make Coal-Fired Electricity Generation Climate Friendly?" Presentation at Emerging Energy Technologies Summit, UC Santa Barbara, California, February 9, 2007. [Note: Statoil has subsequently suspended plans for the Draugen project and announced a study of CO_2 capture at a gas-fired power plant at Tjeldbergodden. BP and Rio Tinto have announced the coal-based "DF–3" project in Australia.]

Enhanced Oil Recovery.—Experience relevant to CCS comes from the oil industry, where CO_2 injection technology and modeling of its subsurface behavior have a proven track record. EOR has been conducted successfully for 35 years in the Permian Basin fields of west Texas and Oklahoma. Regulatory oversight and community acceptance of injection operations for EOR seem well established.

Although the purpose of EOR is not to sequester CO_2 per se, the practice can be adapted to include CO_2 storage opportunities. This approach is being demonstrated in the Weyburn-Midale CO_2 monitoring projects in Saskatchewan, Canada. The Weyburn project uses captured and dried CO_2 from the Dakota Gasification Company's Great Plains synfuels plant near Beulah, North Dakota. The CO_2 is transported via a 200-mile pipeline constructed of standard carbon steel. Over the life of the project, the net CO_2 storage is estimated at 20 million metric tons, while an additional 130 million barrels of oil will be produced.

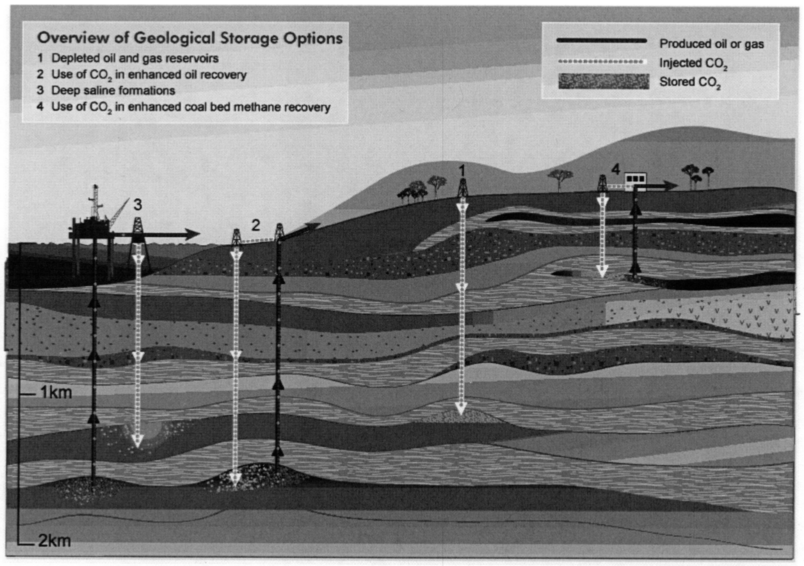
The economic value of EOR with CCS represents an excellent opportunity for initial geologic sequestration projects like Weyburn. In addition, "next generation" CO_2–EOR processes could boost technically recoverable oil resources in the United States by 160 billion barrels, which could help offset oil imports.[4] This also represents a potential demand for an additional 17.5 billion tons of CO_2 in the EOR market.

CCS IN THE UNITED STATES

A DOE-sponsored R&D program, the "Regional Carbon Sequestration Partnerships," is engaged in mapping U.S. geologic formations suitable for CO_2 storage. Evaluations by these Regional Partnerships and others suggest that enough geologic storage capacity exists in the United States to hold several centuries' production of CO_2 from coal-based power plants and other large point sources.

[3] http://www.co2captureandstorage.info/project__specific.php?project__id=26.
[4] http://www.adv-res.com/pdf/Game__Changer__Document.pdf.

The Regional Partnerships are also conducting pilot-scale CO_2 injection validation tests across the country in differing geologic formations, including saline formations, deep unmineable coal seams, and older oil and gas reservoirs. Figure 11 illustrates some of these options. These tests, as well as most commercial applications for long-term storage, will use CO_2 compressed for volumetric efficiency to a liquid-like "supercritical" state; thus, virtually all CO_2 storage will take place in formations at least a half-mile deep, where the risk of leakage to shallower groundwater aquifers or to the surface is less likely to occur.



Source: Peter Cook, CO2CRC, in Intergovernmental Panel on Climate Change, Special Report "Carbon Dioxide Capture and Storage," http://www.ipcc.ch/pub/reports.htm

Figure 11 – Illustration of potential geological CO_2 storage site types

After successful completion of pilot-scale CO_2 storage validation tests, the Partnerships will undertake large-volume storage tests, injecting quantities of ~1 million metric tons of CO_2 or more over a several year period, along with post-injection monitoring to track the absorption of the CO_2 in the target formation(s) and to check for potential leakage.

The EPRI–CURC Roadmap identifies the need for several large-scale integrated demonstrations of CO_2 capture and storage. This assessment was echoed by MIT in its recent Future of Coal report, which calls for 3 to 5 U.S. demonstrations of about 1 million metric tons of CO_2 per year and about 10 worldwide.[5] These demonstrations could be the critical path item in commercialization of CCS technology. In addition, EPRI has identified 10 key topics where further technical and/or policy development is needed before CCS can become fully commercial:

—Caprock integrity;
—Injectivity and storage capacity;
—CO_2 trapping mechanisms;
—CO_2 leakage and permanence;
—CO_2 and mineral interactions;
—Reliable, low-cost monitoring systems;
—Quick response and mitigation and remediation procedures;
—Protection of potable water;
—Mineral rights; and
—Long-term liability.

Figure 12 summarizes the relationship between EPRI's recommended large-scale integrated CO_2 capture and storage demonstrations and the Regional Partnerships' "Phase III" large-volume CO_2 storage tests.

[5] http://web.mit.edu/coal/The__Future__of__Coal.pdf.

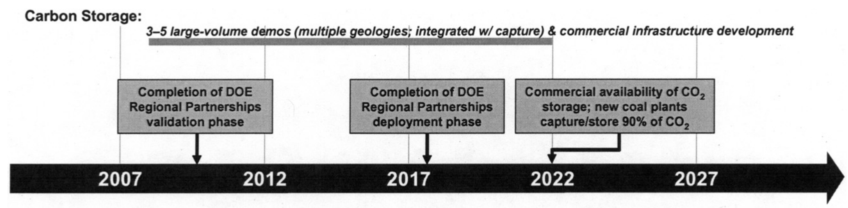


Figure 12 – Timing of CO_2 storage technology RD&D activities and milestones

CO_2 TRANSPORTATION

Mapping of the distribution of potentially suitable CO_2 storage formations across the country, as part of the research by the Regional Partnerships, shows that some areas have ample storage capacity while others appear to have little or none. Thus, implementing CO_2 capture at some power plants may require pipeline transportation for several hundred miles to suitable injection locations, possibly in other states. Although this adds cost, it does not represent a technical hurdle because long-distance, interstate CO_2 pipelines have been used commercially in oilfield EOR applications. Nonetheless, EPRI expects that early commercial CCS projects will take place at coal-based power plants near sequestration sites or an existing CO_2 pipeline. As the number of projects increases, regional CO_2 pipeline networks connecting multiple industrial sources and storage sites will be needed.

POLICY-RELATED LONG-TERM CO_2 STORAGE ISSUES

Beyond developing the technological aspects of CCS, public policy needs to address issues such as CO_2 storage site permitting, long-term monitoring requirements, and liability. CCS represents an emerging industry, and the jurisdiction for regulating it has yet to be determined.

Currently, efforts are under way in some States to establish regulatory frameworks for long-term geologic CO_2 storage. Additionally, stakeholder organizations such as the Interstate Oil and Gas Compact Commission (IOGCC) are developing their own suggested regulatory recommendations for States drafting legislation and regulatory procedures for CO_2 injection and storage operations.[6] Other stakeholders, such as environmental groups, are also offering policy recommendations. EPRI expects this field to become very active soon.

Because some promising sequestration formations underlie multiple States, a State-by-State approach may not be adequate. At the Federal level, the U.S. EPA published a first-of-its-kind guidance (UICPG No. 83) on March 1, 2007, for permitting underground injection of CO_2.[7] This guidance offers flexibility for pilot projects evaluating the practice of CCS, while leaving unresolved the requirements that could apply to future large-scale CCS projects.

LONG-TERM CO_2 STORAGE LIABILITY ISSUES

Long-term liability of storage sites will need to be assigned before CCS can become fully commercial. Because CCS activities will be undertaken to serve the public good, as determined by government policy, and will be implemented in response to anticipated or actual government-imposed limits on CO_2 emissions, a number of policy analysts have suggested that the entities performing these activities should be granted a large measure of long-term risk reduction.

RD&D INVESTMENT FOR ADVANCED COAL AND CCS TECHNOLOGIES

Developing the suite of technologies needed to achieve competitive advanced coal and CCS technologies will require a sustained major investment in RD&D. As shown in Table 3, EPRI has estimated that an expenditure of approximately $8 billion will be required in the 10-year period from 2008–2017. The MIT Future of Coal report estimates the funding need at up to $800–$850 million per year, which approaches the EPRI value. Further, EPRI expects that an RD&D investment of roughly $17 billion will be required over the next 25 years.

Investment in earlier years may be weighted toward IGCC, as this technology is less developed and will require more RD&D investment to reach the desired level

[6] http://www.iogcc.state.ok.us/PDFS/CarbonCaptureandStorageReportandSummary.pdf.
[7] http://www.epa.gov/safewater/uic/pdfs/guide__uic__carbonsequestration__final-03-07.pdf

of commercial viability. As interim progress and future needs cannot be adequately forecast at this time, the years after 2023 do not distinguish between IGCC and PC.

TABLE 3.—RD&D FUNDING NEEDS FOR ADVANCED COAL POWER GENERATION TECHNOLOGIES WITH CO_2 CAPTURE

	2008–12	2013–17	2018–22	2023–27	2028–32
Total Estimated RD&D Funding Needs (Public + Private Sectors)	$830M/yr	$800M/yr	$800M/yr	$620M/yr	$400M/yr
Advanced Combustion, CO_2 Capture	25 percent	25 percent	40 percent	80 percent	80 percent
Integrated Gasification Combined Cycle (IGCC), CO_2 Capture	50 percent	50 percent	40 percent	80 percent	80 percent
CO_2 Storage	25 percent	25 percent	20 percent	20 percent	20 percent

By any measure, these estimated RD&D investments are substantial. EPRI and the members of the CoalFleet for Tomorrow® program, by promoting collaborative ventures among industry stakeholders and governments, believe that the costs of developing critical-path technologies for advanced coal and CCS can be shouldered by multiple participants. EPRI believes that government policy and incentives will also play a key role in fostering CCS technologies through early RD&D stages to achieve widespread, economically feasible deployment capable of achieving major reductions in U.S. CO_2 emissions.

Senator DORGAN. Mr. Phillips, thank you very much.

Let me read some information—some of you may know this—from a Department of Energy report. It says: "The Williston Basin oil [and gas] producing region of North Dakota, South Dakota and Montana has an original oil endowment of about 13 billion barrels," according to the Department of Energy. Of this, they say 4 billion barrels, about 29 percent, will be recovered with primary and secondary oil recovery techniques. But that means 9 billion barrels of oil that they estimate exists will be left in the ground or stranded if they simply follow the use of traditional oil recovery practices.

The report also says that a major portion of this stranded oil is in reservoirs technically and economically amenable to enhanced oil recovery using carbon dioxide injection. Now, it says, that the 13 billion barrels of oil in place for the Williston Basin includes only a modest portion of the larger unconventional oil resource that might be in the Bakken shale. As I indicated earlier, I had the U.S. Geological Survey here in North Dakota. They are redoing the Bakken shale report in, I think, the first quarter of 2008. I would have to go back and check on the date. As soon as we get that, we will have more information about what the potentially recoverable resources are in the Bakken shale.

But it seems to me like there is a significant opportunity, even as we talk now, in additional coal resources being used in plants that will produce CO_2 if we have beneficial use of CO_2 and then can enhance oil recovery in the same region. It seems to me like it's a win on both counts. The question is, first of all, how much of that is just theory and how much of it will be achievable given the economics of all of this? How does one construct the framework for it, the infrastructure to make it happen?

Mr. Harper, let me ask you the first question. You've been doing some real world work in this capturing and moving CO_2, actually selling it in a pipeline. What has Basin Electric learned in partnering with the oil companies to capture, move and use CO_2 for beneficial use? What have you learned?

Mr. HARPER. Well, the first thing we've learned is doing it is not necessarily the easiest thing in the world. I recall when we first turned the valve in 2000, we learned, as did the oil company that they had not successfully prepared their field for the CO_2 to be injected in there. Therefore, there were leaks of the gas. But those have since been fixed. That particular field today, as I understand it, is—it was producing about 10,000 barrels of oil a day. It's now producing over 30. So it's proving out the technology. In fact, I spent last Wednesday and Thursday in the gas plant, as well as up in the Weyburn and Midale fields visiting with customers up there trying to learn more, and what I found is their long-term goal is to capture upwards of 50 percent of the oil out of that field, and that's where they think it will plateau with this current technology. As was said earlier, the oil companies are desirous of as much CO_2 as we can provide them because they see it as a true benefit.

What I also found is that both oil companies are doing different technologies with respect to how they put it into the oilfield, they recycle the existing CO_2. And so it was quite interesting to see again how they're applying the different technologies, which to me is showing that technology will advance as to where we need to be in successfully capturing CO_2 and using it for an incentive for oil production, but, more importantly, to again continue our long-term viability of utilizing fossil fuels. So it's been a tremendous learning curve for us.

As you mentioned earlier, we currently capture about 49 percent of the CO_2. As we look at pieces of legislation, one of the recent ones was a 70 percent capture level, so I asked our engineers at the plant, what would it take for us economically to go from 49 percent to 70 percent? They came back and said it would cost us another $165 million plus another $40 million annually in operating costs. Again, those are huge numbers, but I think, again, as we move our way through the technology developments, and so on, those costs will come down. That's just some of the lessons that we're learning.

Senator DORGAN. All right. One quick question, the CO_2 goes north to the Alberta oilfields, any reason that they were the earlier market as opposed to the oilfields in North Dakota or Montana?

Mr. HARPER. A lot of the work was done prior to me coming here, but I've since learned through additional discussions that the problem was the pricing of the CO_2 and the fact that some of the old companies couldn't come together with the economics to make it work, whereas, on the other side, quite frankly, the Canadian government provided them with an incentive to develop those fields, and so that lent itself to more economic advantage for that customer up there.

Senator DORGAN. So, in addition, it was a public policy initiative?

Mr. HARPER. Absolutely.

Senator DORGAN. Mr. Weeda, you've described in some detail your project, which is, I think, an exciting, interesting and very large project. I believe it could be something that's significant for our region and something, I think, that our country could learn from. We're trying a lot of different applications and models around the country to try to understand what kinds of capabilities we have with various sources of energy. What kinds of challenges do you see, at this point, for the project? What do you need to understand from policymakers for the purposes of this project and its future?

Mr. WEEDA. When we're looking at the American Lignite Energy project, it's certainly a large project, we'll need financial backing. We're focusing on using technologies that are commercially available that we would be able to get performance guarantees on so the bankers would be willing to support the project. And to that extent the public policy that would help assure us that the fluctuation on oil prices, there perhaps could be a policy that would help us face that potential in the event that oil prices went down.

I think incentives for the development, the industry as a whole. We're being careful to try to develop products that would fit into the existing infrastructure and not have to develop a new retailing market, but to be able to get those products into the market, the public policy that would support that, as well. In addition, the CO_2 sequestration portion of it. The CO_2 is separated in the process. We are also looking at enhanced oil recovery. But as was mentioned, the regulatory framework and the liabilities associated with utilization of CO_2 are definitely an important public policy aspect.

Senator DORGAN. Are you optimistic about the future with respect to CO_2 sequestration, even though, as you know, much of it's still in the demonstration stage?

Mr. WEEDA. As we heard from EPRI, similar timeframes of what I have heard about when the technology will be mature enough to go to the bank and be able to finance a project, but we are working closely with EPRI and others on helping develop those opportunities. As I mentioned, we have a goal within our company of reducing our CO_2 footprint so we're very anxious, but we don't see any single technology that's going to get us there, and that's why I mentioned so many projects today, because we're looking at the small increments of CO_2 we can get in each one. One thing I didn't really mention here is the ethanol industry has a CO_2 stream which could be sequestered. We, of course, with other interests here, at Blue Flint and with the coming interests at Spiritwood, would like to see opportunities to sequester that CO_2, as well.

Senator DORGAN. Mr. Nelson, Mr. Harper talked about how public policy in Canada was helpful to that oilfield seeking to engage in the purchase of CO_2.

You seemed in your statement to be fairly enthusiastic about the opportunities here for enhanced oil recovery using CO_2. What kind of public policy initiatives are required, do you think, to move forward, if any?

Mr. NELSON. I do think, first off, just the regulatory and legal framework that allows you to understand who has the liability, what is the permitting requirements, what monitoring requirements are there, et cetera, and that's fairly well detailed in the NPC report. In fact, we worked with your committee on that. That's one.

I think the other one is, and was mentioned a little bit, in terms of using it in EOR, today there are no requirements to sequester the CO_2 in EOR projects. It's mainly to circulate. There's no requirement to actually sequester the CO_2 ultimately. So that's something that should probably be looked at. The other thing that I think was sort of alluded to, and that is that today, in fact, most of the CO_2 that's used in the EOR projects is actually CO_2 that we produced purposely from the ground, where we had it sequestered nicely and taken it out and now are circulating it, so it's a little bit counterintuitive, if you want to reduce CO_2, you take the CO_2 that's been sequestered geologically out of the ground and circulate it. So I think there is scope to look at some incentives to ensure that we are using anthropogenic CO_2 for EOR purposes.

Senator DORGAN. We had invited some local oil interests to testify. They preferred that you speak on their behalf. But is the industry, itself, excited about this, anxious to move toward it, or is it just something that exists that they will take advantage of when it is possible to take advantage of it?

Mr. NELSON. Well, I think it's all driven—I think there are two factors. One is that this is not a new concept. The concept of using CO_2 or other substances to enhance oil production has been around for a long time. That's one. So I don't know that anybody's—a light bulb has gone off in anybody's head because they've known about it. The economics haven't been there.

Second, and Carl alluded to this a little bit, is a lot of the older fields in the United States now are in the hands of independent oil and gas producers, not major oil companies that have big research labs. So I think there is clearly scope to improve our understanding of what happens in the reservoir. That will have to be led by the DOE, and service companies like ours, to get it applied in the field, because most of the oil and gas producers don't have the capability to do it themselves, in the lower 48.

Senator DORGAN. I should mention to you, as you know, the President zeroed out oil and gas research in his budget request.

Mr. NELSON. I know that.

Senator DORGAN. I added money back in, because I don't think that makes a lot of sense. I understand that perhaps some of the majors have some money do some research, but most of the independents do not and, if we're going to try to solve these problems, we have to continue to engage in oil and gas research. That may be counterintuitive for some, but I think that since we're going to use fossil fuel, let's try to evaluate through research, both privately funded and publicly funded, how we do it and develop that base of knowledge.

Mr. NELSON. That's exactly right.

Senator DORGAN. Mr. Phillips, you, as you indicated, testified previously at the Energy Committee. Let's talk about your work. Some people have said to me that there are other beneficial uses of coal, including lignite coal, coal to plastics, obviously coal to synthetic gas, and so on, coal to liquids. You have an array of potential uses. What's your assessment of those potential uses of lignite for North Dakota? What is most advantageous?

Mr. PHILLIPS. Well, we have looked at coal to liquids for transportation fuels, as well as substitute natural gas as they're doing at Great Plains. One of the things that we see is, particularly for coal to liquids, you need such large-scale volumes to make it competitive. You basically build a large coal gasification complex like they have at Great Plains plus a large oil refinery, and that costs billions of dollars, and, frankly, there just aren't that many organizations in the world, much less the United States, able to do those sorts of things. So as GRE was pointing out, there's going to have to be some sort of financial risk mitigation in order to induce various banks to come in and say, okay, we'll put in our share of that several billion dollars. That's why you're not seeing it. Even though oil prices are at a level where these types of things should be competitive, you're not seeing a bunch of them being built simply because it's such a huge hurdle to come up with that kind of money. And, again, no one knows exactly what oil prices will be in the future. So that's the other reason why there's some hesitancy. If oil companies thought that oil prices were going to stay up, they would start building right away.

Senator DORGAN. Mr. Weeda, you raised the question of the size, the scale of the projects of this type. I assume that's an accurate reflection of what's necessary. You can't do commercially viable small projects when you're dealing with this, can you?

Mr. WEEDA. That's correct. We have also found in our studies of this facility that we did need to scale up to the current size to make it more economical and, yes, indeed, it's a major investment and certainly going to take a lot of help to get this into a full-scale project. We are in the middle of what we call the pre-feed study, but the next increment is to go to the full feed study, which is about a $50 million investment.

Senator DORGAN. I'll ask Mr. Harper, you know, we're dealing with this issue of carbon capture now, as part of the climate change calculation. Later we're going to go to conference dealing with energy policy between the House and the Senate. I suspect that will begin in September; it will take a while. But, you know, one of the considerations there will be the issue of carbon capture. There will be a climate change bill, I expect, at some point in this Congress that will begin moving. We don't know the ingredients to that. Right now we need to ask, how do we capture carbon? How do we capture it and sequester it? How do we capture and use it? What are your thoughts about what is achievable generally speaking? Because you've captured and used it for beneficial purposes. Some say "We understand you're going to require carbon capture, but if you require carbon capture at 95 or 98 percent, well at this point we don't see that technology or we don't have that capability and you're just simply shutting down the projects." Give me your assessment of where we are on this discussion about carbon capture.

Mr. HARPER. First understand I'm not an electrical engineer or chemist, but as I listen to my people at the gas plant, my people on the electric generation side, we're talking to major companies, General Electric, Mitsubishi, on and on and on. In fact, when I was at the plant last Wednesday, Mitsubishi happened to be there and we met and discussed it. There are so many little nuances that have to be looked at in technology. For instance, the cleanliness of a sulfur strain can impact how the capture of carbon takes place. So as we look at technologies, my engineers are telling me that if you don't have a very clean sulfur strain, you may have to put on additional technologies to clean it up before it ever goes to the carbon capture process—a major challenge.

But some of the things that were spoken of earlier in Carl's testimony that, I think, plays a large part in this is the public awareness. You know, one of the things I learned by attending an IEA workshop earlier this year was that we can talk about all the technologies, and we will reach some level of technology success in my mind—we will, we have to—but people do not today understand what really is going on here with respect to carbon capture and storage process. They hear it a lot on TV, they hear it in movies, they read it in magazines, but the fact of the matter is the everyday person out there, in my mind, does not understand really what's going on here, because if you look at the costs associated with all of this—you heard the 18th plant down the road is going to be cheaper obviously than the first one. What's that really going to do to our cost of electricity and cost of energy for this country's growing economy, for this world's growing economy?

I guess my concern is that while we will ultimately develop those technologies, we've got to work on public awareness, we have to work on regulatory framework, we have to work on the legal aspects of this thing and set the road map for us to move forward, because if we don't, I think we're going to fail with respect to our economy, and I'm concerned about that.

Now, having said all of that, you heard Carl talk about 2020, 2025. EPRI and all their studies focused on that 2025 timeframe as well. Everybody has a belief today that the IGCC type of technology and carbon capture is already here, they're working, and that's not the reality. The fact of the matter is all of these are in small-scale types of testing going on, and that's what we're trying to prove at Basin Electric at our Antelope Valley Station project, but they're not there yet. We cannot simply stop this economy from growing and say time out until we get the technology to catch up. We have to have in my mind legislation that allows time for these things to develop, incentives for these things to develop; otherwise, we're not going to be successful.

Senator DORGAN. Mr. Nelson, I mentioned to you that the President zeroed out the research for oil and gas, I put the money back in. What will that research money be used for? What will be beneficial in terms of these issues, particularly in the area of using enhanced oil recovery techniques using CO_2?

Mr. NELSON. I think that there's a lot of work still to do, and understand every reservoir is different, so it's not like a plant on the surface where you can build them in cookie-cutter style. So it's important that we understand the differences and nuances, what really happens chemically and physically downhole when we start injecting CO_2. There's also the study you quoted that had these billions of barrels of technically recoverable oil. Part of that was in what's called transition zones, where we're talking about areas where traditionally the oil has not flowed, it's high, it's trapped in very tiny pore spaces, so to get that to flow, there's a lot of work to understand whether that really is feasible or whether it's not, quite honestly.

But I think the other part of it is, and we touched on it earlier, a lot of it ought to go towards demonstration projects which help the independent oil and gas producers in the United States, particularly the lower 48 of the United States, on land, to help them implement these technologies in projects that can start to have an impact. So a lot of it is going toward demonstration projects to help those independents.

Senator DORGAN. Let me ask Carl and Jeffrey, as well. Many of these projects—John Weeda's project, for example, have fairly long lead times, but we're in a period here in this country where policy change is happening. I mean, you can just see what's happening in this country. All of a sudden energy and climate change are fused as part of the consideration of what we do in the future. And so because you have long lead times and large projects, and because we will not go from zero to 60 with a new standard immediately, how do we create a bridge for the certainty that's needed for investors? We're not going to get projects built, we're not going to get projects built to demonstrate or to prove what different kinds of technologies can offer us if we don't tell those who want to build them: "Here's a transition from here to there." I'm not sure I've asked that question very well here.

Let's assume that we're going to get to a point where we require coal to liquids, we get to a point where we require a certain standard of carbon capture, but we're not going to go from here to there within the next 30 days; right? That's not the way you do that. So how do you create the transitional bridge here so that we can continue to get projects built that give us the knowledge and the demonstration of technology that we need as we proceed?

Carl?

Mr. BAUER. I think that's an excellent question. You know, we're asking the industry to fly and they're not even running on this particular issue. They're studying it; they're walking, if you will, through the process. They're making investment out of their own bottom line basically because this whole thing is not required as of yet, so pretty much the R&D has to come off the bottom line so that they at least understand and be able to converse on this as they are. So I'm thinking that, recognizing that point, we need to pick more realistic in-between points that we would like to stimulate them getting to. I think if we look at what's been done over the past decade or two for wind, how we knew we needed to do something about making wind energy a more economically viable contributor to the energy picture.

Well, if we recognize—and I think what we suffer from in the use of coal fuel largely is that, because it's been there a long time, it's assumed it can do whatever it has to do or it won't play, like we can afford it not to play. Well, reality is we cannot afford not to play. To replace half the electricity generation in this country, there is not sufficient financial capital to do that in 3 decades, quite frankly, without having tremendous damage to the country.

So then how do we move and deal with the other big issue, which is how do we get the greenhouse gas down? And I think ways to share—if you go back to the question about why Weyburn instead of the southwestern part of North Dakota, the Canadian Government put up money to put the pipeline in place, there was a small contribution of that from the Federal Government of the United States through DOE's sequestration program, because we want to understand the handling and the injection and how that plays, but I think the projects that have the potential to utilize CO_2 but cannot financially get there because of economics or if you go to coal to liquids, it's a good idea to address these other issues, how do we deal with the CO_2 portion of it seems to be the biggest hurdle right now, find a way for the financial support, whether it's loan guarantees, tax credits and R&D. I think those three forces have to come together to stimulate the same way that the ethanol continues to benefit from some help in making it a market-viable product. Those things all have to go forward.

Now, one of the things, I think—and you know better than I, Senator—the discussion becomes why that fuel versus my fuel. The reality is we need them all. We just do not have a one-trick pony. We have got to have in this country a viable diversity of portfolio to meet the demand. I think if we really look at it that way, we take a similar approach that we've done on some of the renewables with coal/liquids and with moving at least CO_2 towards EOR and defray some of the costs of getting it into a viable position to be for the next decade, mainly of EOR as it moves forward.

Having said that, I do think the plants that get built have a 30- to 40-year life cycle, so one has to say those plants have to recognize that they are going to have another level of performance required eventually in 20 years. And how they begin to set themselves up for that should be part of their initial design process.

Senator DORGAN. Thank you. Jeffrey.

Mr. PHILLIPS. Yes. You said earlier that Congress was going to have to make decisions on climate change policy, and all I can say is better you than me. It's an enormous responsibility and will have significant impacts on our economy obviously.

But in terms of how we could make that transition or that bridge, what we've tried to do in our R&D augmentation study is to point bite-size projects that need to happen in a timeline, with the assumption that 2020 is the time that we need to have full-scale technology proven. And I'll give you just one example of what we're proposing. We're going to take somebody out there who wants to build a new coal plant and say, okay, build that new coal plant with the money that you said you were going to use, and then we will put together a coalition of other companies and perhaps the Federal Government, also, to pay for the cost of adding CO_2 capture to a portion of your powerplant. Maybe it's only 50 percent. Then we will take that CO_2 and if we can sell it for EOR, it will help cover the costs of compressing it, and if we can't, then we're going to have additional incentives to cover the cost for sticking it into the ground. That would be something that we could do—we believe we can get a plant like that going by the 2012 timeframe. If you let that run for 4 or 5 years, you're going to show people that this technology exists such that we would then be in a position where we could then go forward with a plant that was full-scale, a 100 percent—or not a 100 percent capture, but getting as much CO_2 as we felt was needed.

So that's the kind of projects that we're working on. We certainly could use the Federal Government's assistance, whether it's tax incentives or direct funds. We're a 501(c)(3), so I can't push too hard, but obviously any help we can get would be great.

Senator DORGAN. You can't push at all.

I'm going to ask Franz if he has any questions. I want to mention to you, because you're talking about the research that's needed, that in my subcommittee—as I mentioned, Senator Domenici is the ranking member, he was previously the chairman of this subcommittee—we increased funding for coal, oil and gas R&D. We increased it by 30 percent above the President's budget request with $88 million for the Clean Coal Power Initiative, $374 million for coal research and development funding and $30 million for oil and gas research. Within the coal funding account we've put in $132 million for carbon sequestration research, $34 million for innovations for existing plants programs.

The reason I did this is because it's one thing to talk about all of these issues and say we have to use all of our resources, but if you don't fund it, it's just talk. And I can tell you, whether it's education or a whole range of areas, there's a lot of talk and a lot of sloganeering and precious little real investment that's going to make a big difference. If we're going to do this, we've got to invest in research; we've got to invest in the demonstration projects. We just have to do that. And I think Senator Domenici agrees with this. We have a subcommittee that is very interested in changing the priorities of the President's budget and substantially increasing these investment funds.

Franz?

Mr. WUERFMANNSDOBLER. If I might, let me just ask one quick question in terms of how the Senator described a bridge or synergy approach. What is it that government can do, whether it's on the Federal level or a State level, to help get the utilities, the coal, oil, gas, chemical, pipeline and other industries, to start talking to each other more? Most people are saying, yes, we've got to do this. What is it that the government can do in terms of making that happen?

Mr. HARPER. Trying to get us all to talk together. Good question. I think we are. As I travel around, I think the utilities are talking to each other. We're talking to the oil companies. We're talking to the developers, the vendors, trying to find out what we can do to effectively change, find solutions to the challenges that we have.

But, you know, I think the bigger issue again is the funding aspects, but I think even more than that is we don't have targets to shoot at. They're all around the board. You know, if we could as an industry have targets, we've proven that we can meet them, we roll up our sleeves, work together to develop the technologies. But without targets and incentives to get to those targets we don't have anything to shoot at. So if we could have something—and I'll just throw out something here on the table. If we could have something that says by 2020 we will have *x* in place that will move us to that continued ability to burn fossil fuels. Now, that *x* is, you know, use some of the recent legislation, 70 percent capture technology available to go in. I'm not saying it would be on board and working at that time, because it takes a while. I was interested in the 2012 timeframe of the plant being on line. I would like to understand how he's doing that because we're 10 years getting a plant into production. Right, John?

Mr. WEEDA. Yes.

Mr. HARPER. But that's my viewpoint, is I think we are talking, I think we're all interested in finding the ways in which to move us forward, but if we had reasonable targets, achievable targets, I think we have then something to shoot at along with investment opportunities in research and development, et cetera, et cetera.

I do applaud you, Senator, for putting those dollars back in there because you're absolutely right, the energy bill was put forth, but no appropriations were ever made, and that's a challenge.

Senator DORGAN. Anybody else want to comment?

Mr. WEEDA. I would like to comment. Great River Energy believes a good environmental performance is good business, and when public policy can merge those two together, it makes a huge difference. One example I can point to is that because of the SO_2 Cap and Trade Program, Great River Energy took initiative to improve the scrubbing capability in our units, and as a result we're able to offset those costs in the marketplace because we could do it more economically than some other locations. So we would certainly be interested in a program that helped us put CO_2 in that environment, as well.

I would also like to point out that none of our power stations perform today environmentally like they did on day one. We have continued to make improvements, and sometimes it's through those kinds of incentives—the Department of Energy helping us commercialize the coal-drying technology was another great piece in ability to move forward. The support of the ethanol industry has made it possible for us to partner with the ethanol industry with combined heat and power applications. So I think there are a variety of things that public policy can help us do, and looking at some of those past models will certainly help.

Senator DORGAN. Mr. Nelson.

Mr. NELSON. I was just going to echo what's already been said. I do think there is a lot of improvement in terms of dialog between the oil and gas industry and coal industry, et cetera. But I do think it happens quite naturally once we understand where we have to be by 2020 or 2030, we have targets, and the technology will get developed.

I again applaud you for putting money back in, but I think you also have to keep it in perspective in terms of oil and gas, anyway, research. The oil and gas industry will spend about $6 billion this year, so what you want to do is actually leverage that money and make sure it does get applied in projects that will impact the United States, and I think there's ways to do that.

Mr. PHILLIPS. I would just like to make a couple of comments on a couple things that could be done. First of all, we need to make it clear that early movers are not going to be inadvertently penalized for capturing CO_2 and putting it into enhanced oil recovery, because, for instance, we end up giving out credits based on your current CO_2 emissions and they don't get credit for the CO_2 they're already capturing and putting in the ground, they get penalized, versus somebody that didn't do that.

The second thing that needs to be done is we need some type of guidelines on purity of the CO_2 that can go into bulk pipelines, because what we're seeing is a vast array of specifications. The one that Great Plains uses has 1 percent H2S in it, which is 10,000 parts per million. A FutureGen project is looking at using a CO_2 pipeline down in Texas that uses CO_2 of natural sources—underground sources. They're saying you can't put it in unless you have less than 10 parts per million. So we've got 10,000 parts per million in one part of the country, 10 in another. Which one am I supposed to design for? I'll tell you what, the 10 down in Texas is a lot more expensive to design to, and to me it's almost bordering on anti-competitive behavior.

Senator DORGAN. Thank you very much. I did want to mention that Ross Keys was here previously with Congressman Pomeroy's staff. I think he had to leave. I did not introduce Nate Hill, who works with me and Franz on energy issues, as well.

I want to make just a couple of comments as we conclude today. First of all, there are national interests that are significant here. You know, we did EPACT a couple of years ago. We've now done another energy bill complementary to the Energy and Policy Act of 2 years ago. We got another energy bill through the Energy and Commerce Committee on which I serve. The House has done its energy bill and it is very different. It appears to me that in addition to trying to conference an energy bill between the House and the Senate, there will be climate change legislation moving at some point in this Congress which has a relationship to, but is separate from, some of these considerations.

So what I'm hearing is the industry needs some certainty, they need some decisions made in order to proceed, also so that investors have the confidence to proceed. We're all in a situation where we know a lot less about these subjects than we think we know. We have things being done in the research laboratory that give us certain indications, but until you demonstrate them on a commercial scale, until you demonstrate them out there in the real world, you don't know the circumstances or the conditions that might exist.

So this is a very important and a very interesting time. My interest in it is for a couple of reasons. First of all, as a member of the Energy Committee, I well understand the danger that exists with respect to our dependence on foreign energy. If we think this is just fine, to have to worry about whether the Saudi pipeline is going to be open to us forever, then we're not thinking very much. I'm not talking just about the Saudis. I'm talking about all oil suppliers in troubled parts of the world. I think finally that our country is awakening to how unbelievably vulnerable we are to supplies of oil that come from parts of the world over which we have virtually no control. Very few people are focusing on the fact that a substantial portion of the oil is controlled by foreign governments. And if one really wants to get a migraine, go take a look at what the Chinese Government is doing at this point, and has been doing for some while, to capture supplies of energy for the long term for their own needs and then evaluate what that means in supply/demand relationship and prices for our country with our prodigious energy appetite.

Having said all of that, I also have a parochial interest because I live in a great State and we have unbelievable opportunities to produce energy—a lot of energy. As you all know, I'm a big fan of wind energy, I think I held five wind energy conferences over the years, and we now have a lot of wind energy development going on, but I understand that development turned off and on like a light switch because the production tax credit, which the Federal Government just stopped and started and stuttered on, would be turned off and on, off and on, every 2 years, 3 years, 1 year. So, I understand the influence of public policy incentives, in this case tax incentives, on all of these projects.

Even as North Dakota sees more biofuels, more ethanol plants, more wind turbines and more wind farms being developed, I'm especially interested in seeing that we have an opportunity to continue to use our lignite coal and enhance the use of oil and gas production. With respect to lignite, I believe, and I'm going to continue to push, we can do even more in future years. As I chair this subcommittee, I'm going to push for substantially more research and development so that we can get to the point where we can produce our coal in these plants with virtually zero emissions into the atmosphere. I believe that's possible. Our country should aspire to achieve that.

And, second, I also believe that, concerning the kind of plants you're talking about, Mr. Weeda, if we don't find a way to bridge from here to there the opportunity to build demonstration plants for commercial scale, commercial size demonstration plants, then we will have missed something very significant. We're going to be behind the curve rather than in front of the curve. When I say "demonstration," I'm not suggesting a plant that's worth billions of dollars as just a demonstration plant, but is also a plant that will demonstrate to us on a commercial scale what capabilities exist in a wide range of technologies. If we don't understand that, don't learn that through the commercial demonstration of these projects, this country will fall behind rather than move ahead. So I'm very interested in trying to figure out how we bridge from here to there, and I'm a supporter of that effort.

We are going to require carbon capture and we're going to push. I don't think we're going to loaf around as a country saying, yeah, do what you can, God bless you. I just had one of my colleagues offer an amendment like that and it was defeated pretty handily. That's not enough. We're going to set targets; we're going to reach those targets. That's the way we've always been. We're innovative and aggressive. But even in setting those targets, we've got to find ways to understand that the time frame here is short to some, but long to others. If we're talking about 5, 10 and 20 years, which is the kind of timeframes most of us are talking about, we need to have a path in those timeframes to have opportunities to build things. So that's why I appreciate your testimony, Mr. Weeda, because I think you raised those questions. And I don't know how quickly we can answer them, but we've got to get about the business of addressing them.

I think the testimony by all of you was really helpful and will be a contribution to the knowledge of our committee and the U.S. Senate. And, Mr. Bauer, a continuing thank you to you for your work at the National Energy Technology Laboratory, as well as for your counsel to our committee.

ADDITIONAL SUBMITTED STATEMENT

In addition, I would like to include in the record the statement of Dr. Gerald H. Groenewold, Director, Energy & Environmental Research Center, University of North Dakota.

[The statement follows:]

PREPARED STATEMENT OF DR. GERALD H. GROENEWOLD, DIRECTOR, ENERGY & ENVIRONMENTAL RESEARCH CENTER, UNIVERSITY OF NORTH DAKOTA

This written testimony pertains to the Energy & Environmental Research Center's (EERC's) Plains CO_2 Reduction (PCOR) Partnership and its role in carbon management in our region.

The U.S. Department of Energy (DOE) National Energy Technology Laboratory has established the Regional Carbon Sequestration Partnership (RCSP) Program, which is focused on demonstrating the efficacy of carbon sequestration. The seven DOE partnerships (Figure 1) have developed capacity estimates for the major geologic sequestration targets and are currently conducting field validation tests across the United States and Canada. The PCOR Partnership at the EERC represents a diverse group of 68 public and private sector stakeholders (Figure 2) working together to better understand the technical and economic feasibility of capturing and storing CO_2 emissions from stationary sources of CO_2 in the central interior of North America.

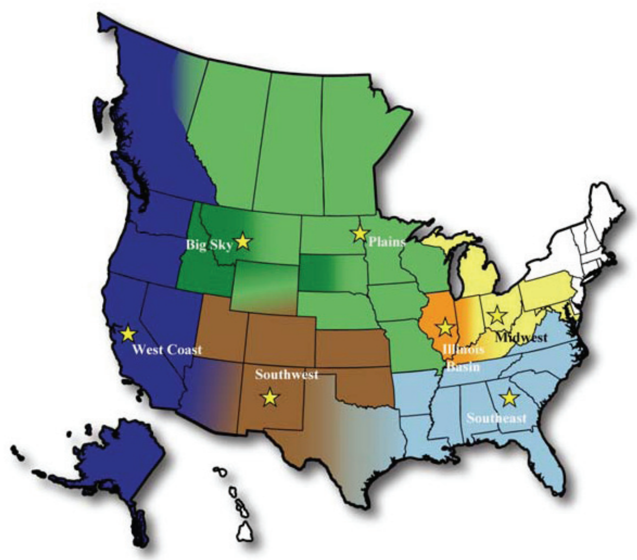


Figure 1. Seven DOE RCSPs.

Figure 2. PCOR Partnership Phase II partners (68, including the EERC).

As part of the DOE RCSP Program, the PCOR Partnership region encompasses all or part of nine States and four Canadian provinces. The PCOR Partnership is managed by the EERC. The PCOR Partnership has developed a credible assessment of the region's major stationary CO_2 sources and sinks and has mobilized the expertise and resources of the industries and local stakeholders who will be a major part of the ultimate success of carbon capture and storage (CCS) technologies. The progress has been rapid, the momentum is great, and the PCOR Partnership is poised to develop a commercial-scale CO_2 sequestration project that will verify the scientific and economic efficacy of geologic sequestration. The next phase of the RCSP Program will result in the injection of 1 million tons or more of CO_2 in each of the seven regions to assess large-scale sequestration in our Nation's varied geologic settings.

The PCOR Partnership is catalyzing opportunities for sequestration in the region and identifying and resolving the technical, regulatory, and environmental barriers that will make carbon sequestration a near-term reality. Throughout its existence, the PCOR Partnership has been engaging policy makers and the public regarding CO_2 emissions, sequestration strategies, and sequestration opportunities. The PCOR Partnership's members include all of the key stakeholders from within the region, along with additional stakeholders representing phenomenal global expertise—stakeholders representing expertise in energy exploration and production, engineering, geology, economics, agriculture, and the environment. PCOR Partnership members provide financial support as well as technical services to the PCOR Partnership by providing data, guidance, and practical experience.

The PCOR Partnership is engaging the industries that will ultimately deploy this new technology. The PCOR Partnership's oil, gas, coal, and utility industry members are working together to develop commercially viable carbon management solutions. In the Williston Basin (Figure 3) of North Dakota, South Dakota, Montana, Saskatchewan, and Manitoba, the juxtaposition of major stationary CO_2 sources (dominated by coal-fired power plants) and ideal potential sinks (oil and gas fields) facilitates the development of enhanced resource recovery opportunities. CO_2-based enhanced oil and gas recovery could easily become a multi-billion-dollar opportunity for our region, resulting in benefits to the environment and energy industries. The favorable geology and socioeconomic conditions may allow our region to become an international showcase for the early implementation of CCS.

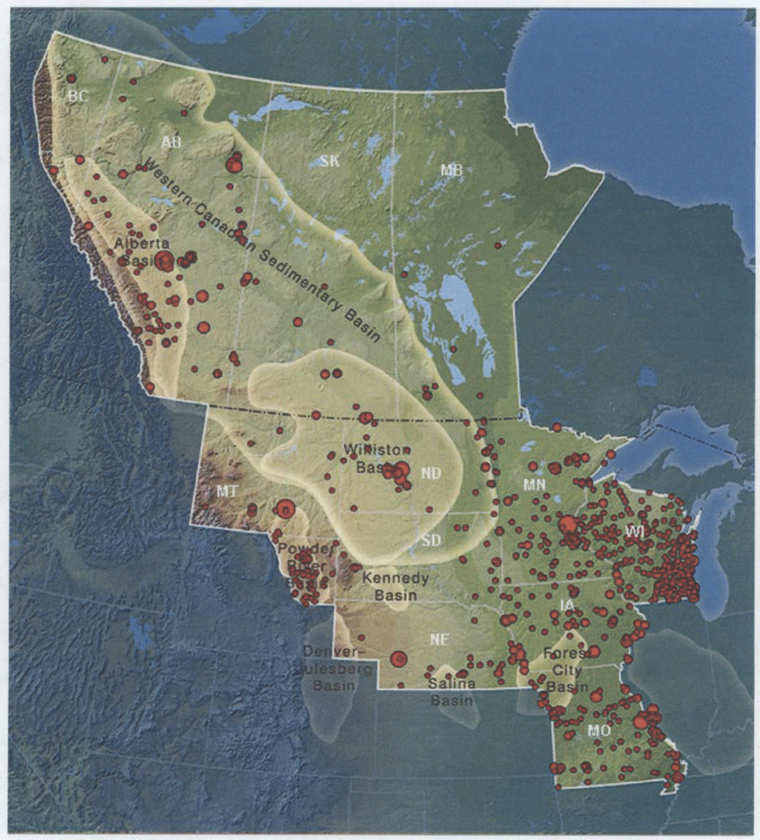


Figure 3. 1225 stationary sources in the PCOR Partnership region.

The PCOR Partnership has developed a regional vision for carbon management that is based initially on enhanced resource recovery projects that build critical infrastructure and expertise for the long-term deployment of CCS technologies. This approach will result in the reduction of greenhouse gases while supporting long-term economic growth on the continent.

For more information on the PCOR Partnership, please see the fact sheets and Phase II Prospectus at http://www.undeerc.org/PCOR/products/factsheet.asp.

CONCLUSION OF HEARING

Senator DORGAN. Does anyone else at the witness table—did you want to add something, last words? If not, let me thank all of you for being here. This hearing is recessed.

[Whereupon, at 11:19 a.m., Monday, August 13, the hearing was concluded, and the subcommittee was recessed, to reconvene subject to the call of the Chair.]

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