PROSPECTS FOR ADVANCED COAL TECHNOLOGIES: EFFICIENT ENERGY PRODUCTION, CARBON CAPTURE AND SEQUESTRATION

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND ENVIRONMENT

COMMITTEE ON SCIENCE AND TECHNOLOGY

HOUSE OF REPRESENTATIVES

ONE HUNDRED TENTH CONGRESS

FIRST SESSION

MAY 15, 2007

Serial No. 110–29

Printed for the use of the Committee on Science and Technology

Available via the World Wide Web: http://www.science.house.gov

U.S. GOVERNMENT PRINTING OFFICE

35–234PS WASHINGTON : 2008

For sale by the Superintendent of Documents, U.S. Government Printing Office
Internet: bookstore.gpo.gov Phone: toll free (866) 512–1800; DC area (202) 512–1800
Fax: (202) 512–2104 Mail: Stop IDCC, Washington, DC 20402–0001

COMMITTEE ON SCIENCE AND TECHNOLOGY

HON. BART GORDON, Tennessee, *Chairman*

JERRY F. COSTELLO, Illinois
EDDIE BERNICE JOHNSON, Texas
LYNN C. WOOLSEY, California
MARK UDALL, Colorado
DAVID WU, Oregon
BRIAN BAIRD, Washington
BRAD MILLER, North Carolina
DANIEL LIPINSKI, Illinois
NICK LAMPSON, Texas
GABRIELLE GIFFORDS, Arizona
JERRY MCNERNEY, California
PAUL KANJORSKI, Pennsylvania
DARLENE HOOLEY, Oregon
STEVEN R. ROTHMAN, New Jersey
MICHAEL M. HONDA, California
JIM MATHESON, Utah
MIKE ROSS, Arkansas
BEN CHANDLER, Kentucky
RUSS CARNAHAN, Missouri
CHARLIE MELANCON, Louisiana
BARON P. HILL, Indiana
HARRY E. MITCHELL, Arizona
CHARLES A. WILSON, Ohio

RALPH M. HALL, Texas
F. JAMES SENSENBRENNER JR., Wisconsin
LAMAR S. SMITH, Texas
DANA ROHRABACHER, California
ROSCOE G. BARTLETT, Maryland
VERNON J. EHLERS, Michigan
FRANK D. LUCAS, Oklahoma
JUDY BIGGERT, Illinois
W. TODD AKIN, Missouri
JO BONNER, Alabama
TOM FEENEY, Florida
RANDY NEUGEBAUER, Texas
BOB INGLIS, South Carolina
DAVID G. REICHERT, Washington
MICHAEL T. MCCAUL, Texas
MARIO DIAZ-BALART, Florida
PHIL GINGREY, Georgia
BRIAN P. BILBRAY, California
ADRIAN SMITH, Nebraska
VACANCY

SUBCOMMITTEE ON ENERGY AND ENVIRONMENT

HON. NICK LAMPSON, Texas, *Chairman*

JERRY F. COSTELLO, Illinois
LYNN C. WOOLSEY, California
DANIEL LIPINSKI, Illinois
GABRIELLE GIFFORDS, Arizona
JERRY MCNERNEY, California
MARK UDALL, Colorado
BRIAN BAIRD, Washington
PAUL KANJORSKI, Pennsylvania
BART GORDON, Tennessee

BOB INGLIS, South Carolina
ROSCOE G. BARTLETT, Maryland
JUDY BIGGERT, Illinois
W. TODD AKIN, Missouri
RANDY NEUGEBAUER, Texas
MICHAEL T. MCCAUL, Texas
MARIO DIAZ-BALART, Florida
RALPH M. HALL, Texas

JEAN FRUCI *Democratic Staff Director*
CHRIS KING *Democratic Professional Staff Member*
MICHELLE DALLAFIOR *Democratic Professional Staff Member*
SHIMERE WILLIAMS *Democratic Professional Staff Member*
ELAINE PAULIONIS *Democratic Professional Staff Member*
ADAM ROSENBERG *Democratic Professional Staff Member*
ELIZABETH STACK *Republican Professional Staff Member*
STACEY STEEP *Research Assistant*

CONTENTS

May 15, 2007

Appendix 1: Answers to Post-Hearing Questions

Appendix 2: Additional Material for the Record

PROSPECTS FOR ADVANCED COAL TECHNOLOGIES: EFFICIENT ENERGY PRODUCTION, CARBON CAPTURE AND SEQUESTRATION

TUESDAY, MAY 15, 2007

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY AND ENVIRONMENT,
COMMITTEE ON SCIENCE AND TECHNOLOGY,
Washington, DC.

The Subcommittee met, pursuant to call, at 1:05 p.m., in Room 2318 of the Rayburn House Office Building, Hon. Nick Lampson [Chairman of the Subcommittee] presiding.

BART GORDON, TENNESSEE
CHAIRMAN

RALPH M. HALL, TEXAS
RANKING MEMBER

U.S. HOUSE OF REPRESENTATIVES

COMMITTEE ON SCIENCE AND TECHNOLOGY

SUITE 2320 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515–6301
(202) 225–6375
TTY: (202) 226–4410
http://science.house.gov

Subcommittee on Energy and Environment

Hearing on

"Prospects for Advanced Coal Technologies: Efficient Energy Production, Carbon Capture and Sequestration"

Tuesday, May 15, 2007
1:00 p.m. to 3:00 p.m.
2318 Rayburn House Office Building

Witness List

Mr. Carl O. Bauer
Director, National Energy Technology Laboratory, Department of Energy

Dr. Robert J. Finley
Director, Energy and Earth Resources Center, Illinois State Geological Survey

Mr. Michael Rencheck
Senior Vice President, Engineering, Projects and Field Services, American Electric Power

Mr. Stuart Dalton
Director, Generation, Electric Power Research Institute

Mr. Gardiner Hill
Director, CCS Technology, Alternative Energy, BP

HEARING CHARTER

SUBCOMMITTEE ON ENERGY AND ENVIRONMENT COMMITTEE ON SCIENCE AND TECHNOLOGY U.S. HOUSE OF REPRESENTATIVES

Prospects for Advanced Coal Technologies: Efficient Energy Production, Carbon Capture and Sequestration

TUESDAY, MAY 15, 2007
1:00 P.M.–3:00 P.M.
2318 RAYBURN HOUSE OFFICE BUILDING

Purpose

On Tuesday, May 15, 2007 the Subcommittee on Energy and Environment of the Committee on Science and Technology will hold a hearing to receive testimony on the advancement of coal technologies and carbon capture and sequestration strategies which will help to reduce the emissions of greenhouse gases, in particular, carbon dioxide.

The Department of Energy has a number of ongoing research and development programs designed to demonstrate advanced technologies that reduce coal power's carbon emissions. In addition, some industry leaders also have begun to invest in advanced coal technologies. The Committee will hear testimony from five witnesses who will speak to the current research, development, demonstration and ultimate commercial application of technologies that enable our power plants to operate more efficiently, reduce emissions, and capture carbon for long-term storage. They will discuss the technological and economic challenges we face in limiting carbon emissions and safely managing the captured carbon on a large scale.

Witnesses

1. **Mr. Carl O. Bauer,** Director of the National Energy Technology Laboratory (NETL), a national laboratory owned and operated by the Department of Energy. In his current position as Director of NETL, he oversees the implementation of major science and technology development programs to resolve the environmental, supply and reliability constraints of producing and using fossil resources, including advanced coal-fueled power generation, carbon sequestration, and environmental control for the existing fleet of fossil steam plants.
2. **Dr. Robert J. Finley,** Director Energy and Earth Resources Center for Illinois State Geological Survey with specialization in fossil energy resources. He is currently heading a regional carbon sequestration partnership in the Illinois Basin aimed at addressing concerns with geological carbon management.
3. **Mr. Michael Rencheck,** Senior Vice President for Engineering Projects and Field Services at American Electric Power headquartered in Columbus, Ohio. He is responsible for engineering, regional maintenance and shop service organizations, projects and construction, and new generation development. He will discuss ongoing projects at AEP and can talk to plant efficiencies and retrofitting facilities to capture carbon.
4. **Mr. Stu Dalton,** Director, Generation at the Electric Power Research Institute. His current research activities cover a wide variety of generation options with special focus on emerging generation, coal-based generation, emission controls and CO_2 capture and storage. He also helped to create the EPRI *Coal Fleet for Tomorrow* program.
5. **Mr. Gardiner Hill,** Director of Technology in Alternative Energy Technology, is responsible for BP group-wide aspects of CO_2 Capture and Storage technology development, demonstration and deployment. He also is the BP manager responsible for the BP/Ford/Princeton Carbon Mitigation Initiative

at Princeton University as well as the BP manager responsible for the BP/Harvard partnership on the Energy Technology Innovation Project. He posses 20 years of technical and managerial experience which is directly relevant to technology, business and project management.

Background

Approximately 50 percent of the electricity generated in the United States is from coal. According to DOE's Energy Information Administration (EIA) carbon dioxide emissions in the United States and its territories were 6,008.6 million metric tons (MMT) in 2005. In the United States, most CO_2 is emitted as a result of the combustion of fossil fuels. In particular, the electric power sector accounts for 40 percent of the CO_2 emissions in the U.S., according to EIA.

If we are going to implement policies to reduce greenhouse gas emissions associated with the use of coal, what technologies are currently available, what technologies need to be developed or improved, and what technical challenges must we overcome to meet that goal? There are two primary approaches to reducing emissions associated with coal-fired power production: increasing the efficiency of coal-fired plants (through replacement with new plants or retrofitting existing plants) and through installation of carbon capture technology and transporting CO_2 to a permanent storage facility.

CO_2 Capture

Retrofitting existing coal-fired power plants to capture carbon is a critical component of any strategy to reduce our emissions of greenhouse gases. Carbon capture applications may be installed in new energy plants or retrofitted to existing plants. Some outstanding issues with retrofitting existing plants include site constraints such as availability of land for the capture equipment and the need for a long remaining plant life to justify the large expense of installing the capture equipment. Another potential barrier to retrofitting is the loss in efficiency that can occur due to the energy required to operate the carbon-capture equipment.

The first step in carbon capture and sequestration is to produce a concentrated stream of CO_2 for capture. Currently, there are three main approaches to capture CO_2 from large-scale industrial facilities or power plants: 1) post-combustion capture, 2) pre-combustion capture, and 3) oxy-fuel combustion capture.

Post-combustion capture process, although not required, involves extracting CO_2 from the flue gas following combustion of fossil fuels. There are commercially available technologies that use chemical solvents to absorb the carbon.

Pre-combustion capture separates CO_2 from the fuel by combining it with air and/or steam to produce hydrogen for combustion and CO_2 for storage. The most commonly discussed type of pre-combustion capture technology is the gasification method. Gasification is a method of taking low-value feedstocks such as coal, biomass or petroleum coke and transforming them through a chemical process to make high value products such as chemicals or electricity. Integrated Gasification Combined Cycle (IGCC)—often discussed as a major breakthrough to improve the environmental performance of coal-based electric power generation—is a form of gasification, which uses syngas created from the gasification process as the feedstock, to power a combined-cycle turbine used to produce electricity. IGCC has the ability to produce a relatively pure stream of CO_2 arguably making it better suited for carbon capture than a pulverized coal plant.

Oxy-fuel combustion capture uses oxygen instead of air for combustion and produces a flue gas that is mostly CO_2 and water which are easily separated. This technique is considered developmental and has not been widely applied for power production, mainly because the temperatures that result from the combustion of pure oxygen are far too high for typical power plant materials.

CO_2 Sequestration

Geologic sequestration of CO_2 is considered the most feasible and widely studied method of storage. There are three main types of geologic formations: 1) oil and gas reservoirs, 2) deep saline reservoirs, and 3) unmineable coal seams.

When CO_2 is injected below 800 meters in a typical reservoir, the pressure induces CO_2 to behave like a relatively dense liquid. This state is known as "supercritical." With each of the three methods listed above, CO_2 would be injected into reservoirs that hold, or previously held liquids or gases. In addition, injecting CO_2 into deep geological formations uses existing technologies that have been primarily developed by and used for the oil and gas industry. For these reasons, geologic sequestration appears to be a promising carbon storage strategy.

Pumping CO_2 into oil and gas reservoirs to boost production, a process known as enhanced oil recovery (EOR) is practiced by the petroleum industry today. Using

EOR for long-term CO_2 storage is beneficial because sequestration costs can be partially offset by revenues from oil and gas production. However, the primary purpose of CO_2 for EOR was not intended to serve the need for long-term sequestration of CO_2 and the degree to which injected CO_2 remains in the reservoir in many areas utilizing EOR is unknown.

Depleted or abandoned oil and gas fields are potential candidates for CO_2 storage because the oil and gas originally trapped did not escape for millions of years demonstrating the structural integrity of these reservoirs. Because of their value as sources of oil and gas, these reservoirs have been mapped and studied and computer models have often been developed to understand how hydrocarbons move in the reservoir. These models could be applied to predict the potential movement of CO_2 within these reservoirs.

Still, there are concerns with using oil and gas reservoirs for CO_2 storage that stem from the stability of the reservoir post-production and the degree of certainty that leakage could be prevented.

A noteworthy project is the Weyburn Project in south-central Canada which uses CO_2 produced from a coal gasification plant in North Dakota for EOR. According to CRS, comprehensive monitoring is being conducted at Weyburn.

Deep saline formations are sedimentary basins saturated with saline or briny water that is unfit for human consumption or agricultural use. As with oil and gas, deep saline reservoirs can be found onshore and offshore. There are advantages of using saline reservoirs for CO_2 sequestration: they are more widespread in the U.S. than oil and gas reservoirs and potentially have the largest reservoir capacity of the three types of geologic formations being considered for carbon sequestration.

The first commercial-scale operation for sequestering CO_2 in a deep saline reservoir is the Sleipner Project in the North Sea. While deep saline reservoirs have huge potential capacity to store CO_2, there is concern about maintaining the integrity of the reservoir because of chemical reactions following CO_2 injection. CO_2 can acidify the fluids in the reservoir, dissolving minerals such as calcium carbonate, and possibly weakening the reliability of the storage site. Increased permeability could allow the CO_2 to create new pathways that lead to contamination of aquifers used for drinking water.

Many coal seams are unmineable with current technology because the coal beds are not thick enough, the beds are too deep, or the structural integrity of the coal bed is inadequate for mining. Because coal beds are highly permeable they tend to trap gases, such as methane, that bind themselves to the coal. CO_2 binds even more tightly to coal than methane, thus making it possible to store the unwanted CO_2 and increase the recovery of the valuable coalbed methane.

Efficient Energy Production and Retrofitting Existing Coal-fired Power Plants

EIA projections show that a two percent increase in coal efficiency would exceed all additional renewable power generation through the EIA forecast period (2030).

Raising the efficiency of power plants is part of the debate on how best to reduce carbon dioxide emissions. Adopting advanced power generating systems could help plant efficiency for coal-fired power plants. For example, the Department of Energy's National Energy Technology Laboratory (NETL) is developing technologies to ensure existing and future coal power systems are more efficient and burn more cleanly. Their work includes gasification, advanced combustion, and turbine and heat engine technologies. Coal power plants operate at approximately a 33 percent efficiency level and NETL is striving to develop technologies for a central power plant that is capable of 60 percent efficiency with near zero emissions by 2020.

In addition to designing new plants to be more efficient, NETL and others are working on technologies that can be utilized to improve the efficiency of existing coal-fired power plants. In the short-term, options such as converting from sub-critical to super-critical steam cycle and combining coal with biomass to fuel plants both offer opportunities to lower CO_2 emissions from existing coal plants.

Chairman LAMPSON. This hearing will come to order, and I am pleased to welcome our witnesses here today to talk about a critical issue: the advancing technologies designed to reduce coal power's carbon dioxide emissions.

I think our panelists will bring a wealth of knowledge to share about cleaner production of electricity at both new and existing coal-fired power plants, and we have several witnesses who will discuss the technical issues regarding long-term geological storage of CO_2. Again, I welcome our witnesses and thank you very much for testifying before the Subcommittee this afternoon.

As many of us know in this room this afternoon, approximately 50 percent of the electricity generated in the United States is from coal. According to DOE's Energy Information Administration, EIA, carbon dioxide emissions in the United States and its territories were just over six billion metric tons in 2005, and the electric power sector generates approximately 40 percent of the Nation's CO_2 emissions.

Because we will continue to rely on coal for a large percentage of our energy consumption for the foreseeable future, there is growing national and global interest in developing strategies to significantly reduce the billions of tons of carbon dioxide released into our atmosphere from this source.

If we are going to implement policies to reduce greenhouse gas emissions associated with the use of coal, today's hearing will help us better understand how far along we have come in meeting this challenge and how much further we may need to go.

I understand that promising technologies are being developed to improve the efficient production of electricity from coal-fired power plants which could help to reduce CO_2 emissions. I look forward to learning more about the deployment of technologies that can capture CO_2 from new and existing power plants and keep it out of the atmosphere.

We must advance our technical ability to capture CO_2 and prepare the heat-trapping gas for safe and effective storage in geologic formations. Without commercialization of carbon capture technologies and effective strategies to transport the CO_2 from capture to long-term storage, we run the risk of profound damages to our climate system.

I believe that coal will continue to remain a major energy source in the United States. I also believe the government, in partnership with private industry and universities, can take great strides in reducing coal's contribution to global warming.

I look forward to hearing from our panelists about the challenges we face to design a carbon capture and sequestration strategy that is sensible and meaningful.

And now, I would like to recognize our distinguished Ranking Member, Mr. Inglis of South Carolina, for his opening statement.

[The prepared statement of Chairman Lampson follows:]

PREPARED STATEMENT OF CHAIRMAN NICK LAMPSON

I am pleased to welcome our witnesses here today to talk about a critical issue—advancing technologies designed to reduce coal power's carbon dioxide emissions.

I think our panelists bring a wealth of knowledge to share about cleaner production of electricity at both new and existing coal-fired power plants. And, we have several witnesses who will discuss the technical issues regarding long-term geological storage of CO_2. Again, I welcome our witnesses and thank you for testifying before the Subcommittee this afternoon.

As many of us in this room know, approximately 50 percent of the electricity generated in the United States is from coal. According to DOE's Energy Information Administration (EIA) carbon dioxide emissions in the United States and its territories were just over six billion metric tons in 2005, and the electric power sector generates approximately 40 percent of the Nation's CO_2 emissions.

Because we will continue to rely on coal for a large percent of our energy consumption for the foreseeable future, there is a growing national and global interest in developing strategies to reduce significantly the billions of tons of carbon dioxide released into our atmosphere from this source.

If we are going to implement policies to reduce greenhouse gas emissions associated with the use of coal, today's hearing will help us better understand how far along we have come in meeting this challenge and how much further we may need to go.

I understand that promising technologies are being developed to improve the efficient production of electricity from coal-fired power plants which could help to reduce CO_2 emissions. I look forward to learning more about the deployment of technologies that can capture CO_2 from new and existing power plants and keep it out of the atmosphere.

We must advance our technical ability to capture CO_2 and prepare the heat-trapping gas for safe and effective storage in geologic formations. Without commercialization of carbon capture technologies and effective strategies to transport the CO_2 from capture to long-term storage, we run the risk of profound damages to our climate system.

I believe that coal will continue to remain a major energy source in the United States. I also believe the government, in partnership with private industry and universities, can take great strides in reducing coal's contribution to global warming.

I look forward to hearing from our panelists about the challenges we face to design a carbon capture and sequestration strategy that is sensible and meaningful.

Mr. INGLIS. And I thank the Chairman. Thank you for holding this hearing on an important topic.

As the Chairman just pointed out, we get a lot of our electricity from coal, and we have a lot of coal available to us, so sequestration seems to be one of the key breakthroughs that we need to achieve in order to make efficient or effective use of this resource.

And you know, we have got a case study in South Carolina right now. Duke Energy faces a decision of whether to build a coal-fired plant or a nuclear power plant, the question of the nuclear plant, I think that it would be preferable, frankly, in that situation, even though it is very expensive, $6 billion. But their probable choice, sounds to me, since I am not connected with the company, I guess we don't have to make any SEC disclosures based on this, but it seems to me that they are probably headed toward the coal-fired plant, which will, 24/7, 365 days a year, have a CO_2 issue associated with it. And somehow, we have got to deal with that, and so, this panel today, I hope, will help us figure out where the science stands with respect to sequestration, and help us know how the government might be a partner in funding some research, or in being the early adopters or the regulators that would cause this technology to advance, and make it so that that plant, if it is built as a coal plant, doesn't create the harmful side effects that we are all concerned about.

So, it is good to be here. It is good to have the opportunity to have some experts that will help us understand the possibilities that are available to us, and Mr. Chairman, I look forward to hearing from our witnesses.

[The prepared statement of Mr. Inglis follows:]

PREPARED STATEMENT OF REPRESENTATIVE BOB INGLIS

Thank you for holding this hearing, Mr. Chairman.

Duke Energy faces a dilemma in South Carolina. They would like to be producing energy free of CO_2 emissions, but because of the extensive licensing hurdles of nuclear, and the high costs of wind and solar power, Duke has been forced to meet increased energy demand by building coal-powered plants. Perhaps if we had clean coal and carbon capture technologies readily available and affordable, companies like Duke would be able to meet growing energy demand with coal and without emissions.

We are currently consuming coal energy at a rapid pace. We need to focus on ways to make that consumption cleaner and more efficient. Clean coal and carbon capture and sequestration technologies offer such solutions. I hope that we can find ways to encourage the implementation of these technologies.

More importantly, I hope that these technologies will be affordable and attractive to U.S. and global industry alike. America can lead the way with technological innovation that can be easily integrated into existing coal plants worldwide. In addition, the research that will soon begin at the FutureGen site, and the construction of IGCC power plants, will be vital for pioneering and demonstrating the many benefits of clean coal and carbon capture and sequestration technologies for other countries.

The future of renewable energy promises an end to our dependence on fossil fuels like oil and coal. But for today, we must work to make sure that our coal consumption is as emission-free and energy efficient as possible, bringing benefits to both industry and the environment.

Thank you again for holding this hearing, Mr. Chairman, and I look forward to hearing from our witnesses.

Chairman LAMPSON. Thank you very much. I ask unanimous consent that all additional opening statements submitted by Subcommittee Members be included in the record. Without objection, so ordered.

[The prepared statement of Mr. Costello follows:]

PREPARED STATEMENT OF REPRESENTATIVE JERRY F. COSTELLO

Mr. Chairman, thank you for calling today's hearing to receive testimony on the advancement of coal technologies and carbon capture and sequestration strategies.

I am privileged to represent the 12th Congressional District of Illinois, a region rich in coal reserves and mining. Coal plays a vital role as an energy source, and the industries involved in the mining, transportation and utilization of coal provide thousands of jobs for people in Illinois and other parts of the country, in addition to economic benefits to many communities across Illinois and the Nation. Further, the Clean Coal Research Center at Southern Illinois University (SIUC), the State of Illinois and its energy industries are committed to the development and application of technologies for the environmentally sound use of Illinois coal.

I believe clean coal technology is part of the solution to achieving U.S. energy independence, continued economic prosperity and improved environmental stewardship. In February, a group of twenty-seven Democrats sent a letter to Speaker Pelosi and Majority Leader Hoyer stating our strong commitment to advance the deployment of clean coal technologies, including carbon capture and sequestration (CCS). In order for carbon capture and sequestration technology to become commercially viable, the Federal Government must show it is committed to the necessary research, development, and demonstration (RD&D). Mr. Chairman, as you know, I have been a strong advocate for federal coal initiatives and programs. I am focused on increasing the funding levels for clean coal research and development (R&D) programs for FY08 because coal is going to be the mainstay for electricity generation well into the future. I intend to continue to work with my colleagues on both sides of the aisle to ensure we continue to advance clean coal technology to overcome the technical and economical challenges for coal-based power plants.

There have been several Committee hearings in the House and Senate to discuss CCS technology. I am glad we are having today's Subcommittee hearing because it is important to clarify that while CCS technology will enable our power plants to operate more efficiently and reduce emissions, there are challenges to overcome before the utilities or the coal industry can deploy CCS technology. The reality is that until CCS technology is ready to be deployed at a commercial scale, a mandate from Congress requiring industry to cap all carbon dioxide underground will shut down coal plants across the country, drive up consumer's electricity bills, and convert power generation plants to burn natural gas. Given the volatility of the oil and gas market, the instability in the Middle East and rising oil and gas prices, we should be moving away from policies that place a greater dependence on foreign resources and instead, focus on improving clean coal R&D and demonstration projects to utilize the natural resources we have here in the U.S. I am interested in hearing from our witnesses further on this point.

With that, again, thank you Chairman Lampson—I look forward to hearing from our witnesses.

Chairman LAMPSON. It is my pleasure to introduce the excellent panel of witnesses that we have here with us this afternoon. Mr. Carl Bauer is the Director of the National Energy Technology Laboratory at the Department of Energy. He is accompanied by Dr. Joseph Strakey, who leads the Strategic Center for Coal at the Laboratory.

Mr. Michael Rencheck is the Senior Vice President of Engineering Projects and Field Services for American Electric Power. Mr. Stuart Dalton is the Director of Generation at the Electric Power Research Institute, and Mr. Gardiner Hill is the Director of the CCS Technology and Alternative Energy for British Petroleum.

And at this time, I would yield to my colleague from Illinois, Mr. Costello, to introduce our fifth witness, Dr. Robert Finley.

Mr. COSTELLO. Mr. Chairman, I thank you, and I thank you for calling this hearing today on this important topic.

Dr. Robert Finley is the Director of Energy and Earth Resources Center for the Illinois State Geological Survey. Dr. Finley is the head of a Regional Carbon Sequestration Partnership in the Illinois Basin aimed at addressing concerns with geological carbon management. We look forward to hearing from him today, as well as the other witnesses, and I might add that we have had the opportunity to discuss this important issue with Dr. Finley in the past, and we look forward to hearing his testimony and the testimony of the other witnesses.

I thank you, Mr. Chairman.

Chairman LAMPSON. Thank you, Mr. Costello.

You will each have five minutes for your spoken testimony. Your full written testimony will be included in the record for the hearing, and when each of you has completed your testimony, we will begin with questions, and each Member will have five minutes to question the panel.

Mr. Bauer, would you begin, please.

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

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

Our economic prosperity was built upon abundance of fossil fuels, and we have approximately a 250 year supply of coal in the United States. The continued use of this secure domestic resource is critically dependent on developing cost-effective technology options to meet our environmental goals, including the reduction of carbon dioxide.

Carbon capture and storage, or CCS, offers a great opportunity to reduce these potential emissions, and the U.S. and Canada are blessed with an abundance of potential geologic storage capacity for CO_2. The current facts store annual CO_2 emissions associated with all current energy production and use in North America for a period of about 500 years.

Our coal technology program includes development of advanced technologies for pre-combustion or gasification, post-combustion, and oxy-combustion, multiple pathways to produce power and capture CO_2, as well as a robust program for carbon sequestration. The 2012 program goal is to show that we can develop advanced technology to capture and store at least 90 percent of the potential CO_2 emissions from coal-fired power plants, with less than a 10 percent increase in the cost of electricity. Commercially available technology to do this today would add from 30 to 70 percent to the present price of electricity.

Gasification is a pre-combustion pathway to convert coal biomass or carbon containing feedstocks into clean synthesis gas for use in producing power, fuel, chemicals, and hydrogen. The gasification technologies being developed meet the most stringent environmental regulations in any state and provide the opportunity for potential efficient capture of CO_2.

The Power System Development Facility in Wilsonville, Alabama provides a pilot-scale test platform for evaluating critical process components. The transport gasifier at the PSDF is showing great promise for cost-effective gasification of low-rank, high-moisture western coals. Recent successful testing of the Stamet dry-feed coal pump indicates a breakthrough, allowing coal to be pumped directly into a high-pressure gasifier, and thus avoiding the need for coal drying and complex feeding systems.

Another major development is the ion transport membrane technology. This is a more efficient and lower cost method for producing oxygen which is needed for these processes. This year, we are testing the robustness of the technology at Air Products' Sparrows Point facility.

Finally, we are successfully testing at Research Triangle Institute's warm gas sulfur cleanup system at Eastman Chemical's facility in Kingsport, Tennessee. They have a gasifier there that uses coal. Since last fall, the test unit has performed exceptionally well and achieved extremely low sulfur levels.

The Advanced Turbine Program is developing and testing advanced turbine technologies for use of hydrogen as a fuel. A key need for zero-emission coal gasification plants. We plan to increase the efficiency of these turbines by two to three percentage points, while reducing the nitrous oxide emissions to ultra-low t parts per million. High temperature solid oxide fuel cells are being developed for a variety of applications under the SECA program. These fuel cells offer several significant advantages to coal-based near-zero-emissions power systems, and are focused on operating on coal-derived syngas.

DOE's carbon sequestration program leverages basic and applied research with field verification to assess the technical and economic viability of CCS. The key challenges for this program are to demonstrate the ability to capture and store CO_2 in underground geologic formations with long-term stability, develop the ability to monitor and verify the fate of the CO_2, and to gain public and regulatory acceptance. DOE's seven Regional Carbon Sequestration Partnerships are engaged in a major effort to develop and validate the CCS technology in different geologies across the U.S.

DOE also recognizes the importance of the existing fleet of coal-fired power plants in meeting energy demand and possible future carbon constraints. Research is being pursued to dramatically lower the cost of capturing CO_2 from these plants.

The FutureGen project is an industry/government partnership designed to build and operate a gasification-based, nearly emission-free, coal-fired electricity production plant. The 275-megawatt plant will serve as a large-scale laboratory for the validating of the commercial readiness of the technologies that are emerging from the base coal R&D pipeline. The important data and experience from FutureGen will lead to design of the next generation of near-zero-emission coal plants, and provide information for industry, financial investors, and regulatory partners to understand how better to regulate and operate these plants.

Mr. Chairman and Members of the Committee, this completes my statement, and I would be happy to take any questions you may have at this time or later. Thank you.

[The prepared statement of Mr. Bauer follows:]

PREPARED STATEMENT OF CARL O. BAUER

Thank you Mr. Chairman and Members of the Committee. 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. We have approximately a 250-year supply of coal available in the United States, at our current consumption rates. Coal-fired power plants supply over half of our electricity today; the continued use of this secure domestic resource is critically dependent on the development of cost-effective technology options to meet our environmental goals, including the reduction of carbon dioxide (CO_2) emissions.

Carbon capture and storage (CCS) technologies offer a great opportunity to reduce these potential emissions. Fortunately, the United States and Canada are blessed with an abundance of potential geologic storage capacity. At the current rate of energy production and use, we could potentially store all of the associated CO_2 emissions in North America that are produced over the next 175 to 500 years, according to the geologic storage capacity estimates recently made by DOE's Regional Carbon Sequestration Partnerships. These results were recently published in the *"Carbon Sequestration Atlas of the United States and Canada"* that is available on our website at *http://www.netl.doe.gov/publications/carbon_seq/refshelf.html.*

The two greatest challenges facing technology development for clean power production integrated with CCS are reducing the cost of carbon capture and proving the safety and efficiency of long-term geologic storage of CO_2. DOE supports a robust RD&D program specifically designed to address these challenges. The Office of Fossil Energy's core Coal Technology Program includes the development of advanced technologies for pre-combustion (or gasification), post-combustion, and oxy-combustion—multiple pathways to produce power and capture CO_2—as well as a robust program for carbon sequestration to prove the viability of long-term geologic and terrestrial storage. DOE's Office of Science also supports basic research in areas such as combustion chemistry, fundamentally new materials, and modeling of combustion reactions that underpin the development of potential future clean coal technologies, and basic research towards improving our scientific understanding of the behavior of CO_2 at potential geological sites.

The 2012 goal of the Coal Technology Program is to show that we can develop advanced technology to capture and store at least 90 percent of the potential CO_2 emissions from coal-fired power plants, with less than a 10 percent increase in the cost of electricity. This is an ambitious and significant goal, considering that commercially available technology to do this today will add from 30 to 70 percent to the cost of electricity.

Based on the Energy Information Administration's 2007 new capacity forecast, 145 gigawatts of new coal-based capacity will be required in the United States by 2030, while still maintaining most of the 300 gigawatts of generating capacity in the existing coal fleet. We have a fast-approaching opportunity to introduce a "new breed" of power plant—one that is highly efficient, capable of producing multiple products, and is virtually pollution-free ("near-zero" emissions, including carbon). In addition to technology for new plants, we are also likely to need technology that will permit efficient, cost-effective capture of CO_2 emissions from the existing fleet. DOE's R&D program is aimed at providing the scientific and technological foundation for carbon capture and storage for both new and existing coal-fueled power plants.

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, which 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. We are developing advanced gasification technology 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-emission" coal-based energy.

The portfolio of gasification projects that we are developing in partnership with industry covers a broad range of approaches. I'd like to highlight some of the important recent developments.

The Power Systems Development Facility (PSDF) in Wilsonville, Alabama, operated by the Southern Company for DOE, provides a pilot-scale test platform for evaluating components critical to the evolution of gasification technology. The "transport gasifier" under development at the PSDF is proving to be very promising in terms of efficiency and cost, especially for gasifying low-rank, high-moisture western coals. Data from this facility is providing the design basis for scaling technology components to full-size in support of near-zero-emission coal systems.

The Stamet dry-feed coal pump is another promising gasification sub-system that we have been sponsoring. It allows coal to be "pumped" directly into a high-pressure gasifier, thus avoiding the need for coal drying and a complex and costly lock hopper feeding system—or, alternatively, a slurry feeding system that is inefficient when used to feed high-moisture western coals. We have tested the system successfully at the PSDF, and in recent tests at Stamet's facilities in California where operation was successfully demonstrated at conditions typical of high-pressure gasifiers.

Another major program objective is the development of ion transport membrane (ITM) technology, an alternative to conventional cryogenic methods for oxygen production that promises capital cost reductions of $130 per kilowatt, and efficiency improvements of about one percent when integrated into oxygen-based gasification systems. This year we will test the robustness of the membranes under various process conditions and upsets in a five-ton-per-day unit that is operating at Air Products and Chemicals, Inc.'s, Sparrows Point industrial gas facility located near Baltimore, Maryland. The information generated from this small unit will be used to design and test a 150-ton-per-day facility that will pave the way for a full-scale commercial unit in the Department's FutureGen Project, discussed further below.

Finally, we have been successfully testing the Research Triangle Institute's (RTI's) warm gas sulfur cleanup system at Eastman Chemical's Kingsport, Tennessee, chemical complex where a small syngas slipstream is taken from commercial coal gasifiers and processed in a transport desulfurization unit. Since last fall—in over 2,000 hours of operation—the unit has performed exceptionally well, achieving extremely low sulfur levels compared to existing commercial technologies. This new technology offers potential for capital cost reductions of $250 per kilowatt and efficiency improvements of three to four percent. We are currently in negotiations with RTI to scale up this technology for testing at a commercial Integrated Gasification Combined Cycle (IGCC) facility.

The *Advanced Turbine Program* is leveraging the knowledge gained from previous turbine R&D activities to make unprecedented gains in state-of-the-art turbine designs. Potential pathways to advanced turbine designs for high-hydrogen fuels include increasing turbine inlet temperatures, developing advanced combustor designs, increasing compression ratios, and integrating air separation and CO_2 compression.

For near-zero-emission power plants, a new generation of turbine technology is needed that is capable of operating on hydrogen fuels, without compromising operational performance, while achieving ultra-low NO_X emissions.

A primary goal of the Advanced Turbines Program is to show by 2012 that we can operate on hydrogen fuel, increase efficiency by two to three percentage points over baseline, and reduce NO_X emissions to two parts per million (ppm). At the same time, we hope to reduce capital cost when compared to today's turbines in existing IGCC plants. We are working with two of the turbine original equipment manufacturers, General Electric and Siemens Westinghouse, to meet these goals.

To facilitate the development of near-zero-emission coal-based power systems, the Advanced Turbines Program is also funding R&D on oxygen-fired (oxy-fuel) turbines and combustors that provide high efficiency through the use of ultra-high-temperature power cycles. Bringing such oxy-fuel combustors and turbines to commercial viability will require development and integrated testing of the combustor, turbine components, advanced cooling technology, and materials.

To reduce the costs associated with sequestering CO_2, the Advanced Turbines Program is investigating novel approaches for CO_2 compression, including development of the Ramgen shock-wave compression technology. Successful development will reduce the substantial power requirements and costs associated with compression for any zero-emission approach.

The Office of Fossil Energy has been developing high-temperature *Solid Oxide Fuel Cells* for a variety of applications under the Solid State Energy Conversion Alliance (SECA) program. These high-temperature fuel cells offer several significant advantages to coal-based near-zero-emission power systems. Recognizing the strategic importance of being able to operate on domestic fuel resources, namely, coal, we are refocusing the program to coal-based power generation applications.

First, electrochemical power generation is highly efficient and can result in large savings by reducing the size and cost of the up-front gasification and clean-up parts of the plant, as well as by reducing the amount of CO_2 that has to be sequestered.

Second, solid oxide technology can directly utilize carbon monoxide and methane produced in gasification without the need to shift the composition of the syngas to pure hydrogen, which incurs cost and efficiency penalties.

Third, solid oxide fuel cells have built-in carbon separation capability if the anode (fuel side) and cathode (oxidant side) streams are not mixed. We expect that fuel cells will provide over a 10 percentage point increase in efficiency in near-zero-emission systems, with capital costs comparable to or lower than current gas turbine/steam turbine systems.

DOE's *Carbon Sequestration Program* leverages basic and applied research with field verification to assess the technical and economic viability of CCS as a greenhouse gas mitigation option. The Program encompasses two main elements: Core R&D and Validation and Deployment. The Core R&D element focuses on technology solutions, including low-cost, low-energy intensive capture technologies, that can be validated and deployed in the field. Lessons learned from field tests are fed back to the Core R&D element to guide future R&D.

The key challenges the program is addressing are to demonstrate the ability to store CO_2 in underground geologic formations with long-term stability (permanence), to develop the ability to monitor and verify the fate of CO_2, and to gain public and regulatory acceptance. DOE's seven Regional Carbon Sequestration Partnerships are engaged in an effort to develop and validate CCS technology in different geologies across the Nation.

Collectively, the seven Partnerships represent regions encompassing 97 percent of coal-fired CO_2 emissions, 97 percent of industrial CO_2 emissions, 97 percent of the total land mass, and essentially all of the geologic storage sites in the United States potentially available for sequestration. The Partnerships are evaluating numerous CCS approaches to assess which approaches are best suited for specific geologies, and are developing the framework needed to validate and potentially deploy the most promising technologies.

The Regional Partnership initiative is using a three-phased approach.

Characterization, the first phase, was initiated in 2003 and focused on characterizing regional opportunities for CCS, and identifying regional CO_2 sources and storage formations. The Characterization Phase was completed in 2005 and led to the current Validation Phase.

Validation, the second phase, focuses on field tests to validate the efficacy of CCS technologies in a variety of geologic storage sites throughout the United States. Using the extensive data and information gathered during the Characterization Phase, the seven Partnerships identified the most promising opportunities for storage in their regions and are performing widespread, multiple geologic field tests. In addition, the Partnerships are verifying regional CO_2 storage capacities, satisfying project permitting requirements, and conducting public outreach and education activities.

Deployment, the third phase, involves large-volume injection tests. This phase was initiated this fiscal year and will demonstrate CO_2 injection and storage at a scale necessary to demonstrate potential future commercial deployment. The geologic structures to be tested during these large-volume storage tests will serve as potential candidate sites for the future deployment of technologies demonstrated in the FutureGen Project as well as the Clean Coal Power Initiative (CCPI). The Department expects to issue a CCPI solicitation for carbon capture technologies at commercial scale in 2007.

DOE also recognizes the importance of the existing fleet of coal-fired power plants in meeting energy demand and possible future carbon constraints. Research is being pursued to develop technologies that dramatically lower the cost of capturing CO_2 from power plant stack emissions. This research, supported by the Office of Fossil Energy, is exploring a wide range of approaches that includes membranes, ionic liquids, metal organic frameworks, improved CO_2 sorbents, advanced combustor concepts, advanced scrubbing, and oxy-combustion. Additionally, advanced research is being pursued on high-temperature materials, advanced sensors & controls, and advanced visualization software. These developments could provide significant efficiency improvements and cost reductions for both existing and future power plants, based on pulverized coal combustion.

The *FutureGen Project* is an industry/government partnership to design, build, and operate a gasification-based, nearly emission-free, coal-fired electricity production plant. The 275-megawatt plant will be the cleanest fossil-fuel-fired power plant in the world. With respect to sequestration technologies, FutureGen will test, and ideally demonstrate the large-scale, permanent sequestration of the captured CO_2 in a deep saline formation. FutureGen is scheduled to operate from 2012 to 2016, followed by a CO_2 monitoring phase. The data and experience derived from this important endeavor will then be available to facilitate the design of the next generation of near-zero-emission plants.

By working in partnership with other federal agencies, utilities, coal companies, research organizations, academia, and non-government organizations, we hope to make near-zero-emission coal technology a cost-effective and safe option to help meet our future power needs.

Mr. Chairman, and Members of the Committee, this completes my statement. I would be happy to take any questions you may have at this time.

BIOGRAPHY FOR CARL O. BAUER

Carl Bauer is Director of the National Energy Technology Laboratory (NETL), a national laboratory owned and operated by the U.S. Department of Energy (DOE). In this position, he oversees the implementation of major science and technology development programs to resolve the environmental, supply, and reliability constraints of producing and using fossil resources. This includes technologies for—

- Advanced coal-fueled power generation and hydrogen production.
- Carbon sequestration.
- Environmental control for the existing fleet of fossil steam plants.
- Improving the efficiency and environmental quality of domestic oil and natural gas exploration, production, and processing.

Mr. Bauer served as NETL's Deputy Director from October 2003 until his current appointment in February 2005. In his previous position, Mr. Bauer was responsible for NETL's energy assurance and infrastructure protection activities, and he provided oversight for the Office of Institutional and Business Operations; the Office of Science, Technology, and Analysis; and the Office of Technology Impacts and International Coordination.

Prior to serving as Deputy Director, Mr. Bauer was the Director of NETL's Office of Coal and Environmental Systems, with responsibility for all of NETL's activities related to coal and environmental research. Prior to that, he was Director of NETL's Office of Product Management for Environmental Management, with responsibility for development and demonstration of hazardous- and radioactive-waste cleanup technologies.

Mr. Bauer has more than 30 years of experience in technical and business management in both the public and private sectors. His positions at the Department of Energy Headquarters have included Director of the Division of Work for Other Agencies, Director of the Idaho and Chicago Environmental Restoration Operations Division, Acting Director for the Environmental Management Office of Acquisition Management, and Director of the Office of Technology Systems. He has also served as Director of Engineering Support and Logistics, Naval Sea Systems Command for the U.S. Department of Defense; Vice President and General Manager of Technology Application, Inc.; and Vice President, Ship Systems and Logistics Group, Atlantic Research Corporation.

Mr. Bauer received an M.S. in nuclear power engineering from the Naval Nuclear Power Postgraduate Program in 1972 and a B.S. in marine engineering/oceanography from the U.S. Naval Academy in 1971. He has taken additional postgraduate courses at the Wharton School of Business and George Washington University in business administration, finance, and management, and has received additional executive management training at Harvard University's John F. Kennedy School of Government.

Chairman LAMPSON. Thank you, Mr. Bauer. We will postpone those questions for just a few minutes. Dr. Finley.

STATEMENT OF DR. ROBERT J. FINLEY, DIRECTOR, ENERGY AND EARTH RESOURCES CENTER, ILLINOIS STATE GEOLOGICAL SURVEY

Dr. FINLEY. Thank you, Mr. Chairman and Members of the Committee.

Understanding the capacity to geologically sequester carbon dioxide as a byproduct of fossil fuel use, including the use of advanced coal technologies, is an essential strategy to mitigate the growing potential for climate change related to CO_2 buildup in the atmosphere.

At the Illinois State Geological Survey, we have been investigating this capacity for more than five years, and since October of 2003, have been doing so as part of a competitively awarded U.S. Department of Energy Regional Carbon Sequestration Partnership. This partnership covers the Illinois Basin, a geological feature that covers most of Illinois, Southwestern Indiana, and Western Kentucky.

Our Phase I effort focused on compiling and evaluating existing data, and resulted in a 496-page report, indicating that one, suitable CO_2 sequestration reservoirs are present in the Illinois Basin, and that sufficient sequestration capacity existed to warrant further investigation. We then entered a Phase II validation effort, in which we are currently engaged, in which six small-scale field pilot projects will be carried out through September 2009.

In July 2006, DOE managers of the Regional Carbon Sequestration Partnership began the process of developing a Carbon Sequestration Atlas of the United States and Canada. This Atlas was released in digital form in March of this year, and the first edition of the printed version was released last week at the DOE Annual Carbon Capture and Sequestration Conference. I have a copy of it here that Members may peruse at their leisure. I would be pleased to leave it with you.

The Atlas suggests that there are some 3,500 billion tons of storage capacity in the regions covered by the partnerships. In my judgment, there is sufficient geological carbon sequestration capacity in the United States for geological sequestration to be one of multiple tools used on a large scale to reduce CO_2 emissions from fixed sources, such as coal gasification facilities.

While compiling our Phase I report, and while setting up environmental monitoring programs are integral to each of the six field pilots, we have been aware of the need to understand the risks, both short-term and long-term, of geological carbon sequestration. We have been paying as much attention to the overlying rock that will hold the carbon dioxide in place, the caprock or the seals, as we have to the rock into which the CO_2 itself will be injected.

To be an effective climate change mitigation strategy, the CO_2 must remain in place and not leak back to the atmosphere, not contaminate potable groundwater, not affect surface biota, and not present a risk to human health and safety. We know that rock formations can perform this in an effective manner, as both reservoirs and seals, because they have trapped and held oil and natural gas that we drill for and produce every day. These hydrocarbons have been trapped in place for millions to hundreds of millions of years before being brought to the surface through wells. To minimize the risk of CO_2 injection, the reverse of the process of oil and natural gas production, we need to apply many of these same advanced methods that we use to find oil and natural gas. We need to evaluate subsurface rock formations to find thick and competent reservoir seals, to avoid areas where faults and fractures could become leakage pathways, and to understand the chemical changes in the pore space of the rock where the CO_2 will be injected.

With respect to the safety of established projects, we have been injecting CO_2 for enhanced oil recovery in reservoirs in West Texas for more than two decades. Since 1983, more than 600 million tons of pressurized CO_2 have been injected into the surface, and 30 million tons are being injected currently on an annual basis. The safety record of this process has been excellent, with not a single loss of life incident during the period of injection. The injection of one million tons per year of CO_2 for sequestration beneath the seabed of the North Sea has been taking place since 1996, and based on published reports, this process has been both safe and effective.

I would conclude from this experience with CO_2, and from industry experience with geological storage of natural gas, that we could readily proceed with large-scale, by which I mean one million tons per year tests of geological sequestration for further evaluation of reservoirs and caprocks as they vary geologically around the country.

To establish public confidence, all the regional partnerships have been carrying out outreach and education activities, and have been integrating environmental monitoring into our small-scale CO_2 pilot tests. As we move to the upcoming larger scale tests, we need to invest even more into education, outreach, and especially environmental monitoring to ensure public confidence. Our experience to date, very much informed by the public meetings that we have held in regard to the two FutureGen finalist sites, which we are fortunate to have in the State of Illinois, has been the process of ensuring openness and transparency to help gain the public trust. Yes, we are putting something new into the subsurface. Yes, there are small and difficult to quantify risks, such as slow leakage, involved in carrying out any such effort, but yes, we are working diligently and in the most open way possible to investigate the geology of sequestration, and I believe that the geologic framework has the capacity and the security that we require to make sequestration a viable carbon management strategy.

Thank you.

[The prepared statement of Dr. Finley follows:]

PREPARED STATEMENT OF ROBERT J. FINLEY

Understanding the capacity to geologically sequester carbon dioxide (CO_2) as a by-product of fossil fuel use, including the use of advanced coal technologies, is an essential strategy to mitigate the growing potential for climate change related to carbon dioxide buildup in the atmosphere. At the Illinois State Geological Survey, we have been investigating this capacity for more than five years, and, since October of 2003, have been doing so as part of a U.S. Department of Energy (DOE) Regional Carbon Sequestration Partnership. This Partnership covers the Illinois Basin, a geological feature that extends across most of Illinois, southwestern Indiana, and western Kentucky. Our sister geological surveys in Indiana and Kentucky are our partners in this research. Our Phase I effort focused on compiling and evaluating existing data and resulted in a 496-page report in December 2005 indicating 1) that suitable CO_2 sequestration reservoirs were present in the Illinois Basin, and that 2) sufficient sequestration capacity existed warranting further investigation. We then entered a Phase II validation effort, in which we are currently engaged, in which six small-scale, field pilot injection projects will be carried out through September 2009. The injection phase of one field pilot has been completed and two more will see either injection or drilling of new wells for injection within the next 90 days. While planning and executing these field pilot projects, we have also been making further detailed assessments of geological storage capacity, as have the other six partnerships.

In July 2006, DOE managers for the Regional Carbon Sequestration Partnerships convened a meeting at the Kansas Geological Survey to begin the process of developing a Carbon Sequestration Atlas of the United States and Canada. This Atlas was released in digital form in March 2007 and the first edition of the printed version was released last week in Pittsburgh at DOE's annual carbon capture and sequestration conference. The Atlas was developed on the basis of regional partnership work that began in 2003, and earlier, to understand the major geological reservoirs that may be utilized for carbon sequestration. This Atlas also builds on the work supported by DOE in the form of the original MIDCARB, and now NATCARB, digital databases that are accessible on the Internet. The Atlas documented some 3,500 billion tons of storage capacity in the regions covered by the Partnerships. In my judgment there is sufficient geological carbon sequestration capacity in the United States for geological sequestration to be one of multiple tools useful on a large scale to reduce CO_2 emissions from fixed sources such as coal gasification facilities. In the Illinois Basin region, if we could capture 80 percent of all current fixed-source emissions, a volume of 237 million tons of CO_2 per year, we would have storage capacity for 122 to 485 years of emissions just in the deep saline reservoirs.

While compiling our Phase I report, and while setting up environmental monitoring programs integral to each of our six field pilot projects, we have been aware of the need to understand the risks, both short- and long-term, of geological carbon sequestration. We have been paying as much attention to the overlying rock that will hold the carbon dioxide in place, the reservoir seal or caprock, as we have to the qualities of the reservoir rock that the CO_2 will be injected into. To be an effective climate change mitigation strategy, the CO_2 must remain in place and not leak back to the atmosphere, not contaminate potable ground water, not affect surface biota, and not present a risk to human health and safety. That implies that we must do an excellent job of investigating the properties of these rocks and the fluids now within them and predicting their performance in the future. We know that rock formations can perform as effective reservoirs and seals because they have trapped and held the oil and natural gas that we drill for and produce every day. These hydrocarbons have been trapped in place for millions to hundreds of millions of years before being brought to the surface through wells. To minimize the risk in CO_2 *injection,* the reverse of the oil or natural gas *production* process, we need to apply many of the same advanced methods as we use to find oil and natural gas. We need to evaluate subsurface rock formations to find thick and competent reservoir seals, to avoid areas where faults and fractures could become leakage pathways, and to understand the chemical changes in the pore space of the rock that the CO_2 will be injected into. All of this can be done to mitigate risk and if done well, and in sufficient detail, will allow appropriate sites with minimum risk to be selected for geological sequestration. After all, we also have decades of experience with underground natural gas storage projects at sites where tens of billions of cubic feet of flammable natural gas are stored safely and effectively.

With respect to the safety of established projects, we have been injecting CO_2 for enhanced oil recovery in West Texas for more than two decades. Since 1983, more than 600 million tons of pressurized CO_2 have been injected and 30 million tons are currently being injected annually in West Texas oil reservoirs. The safety record of this process has been excellent with not a single incident of loss of life. The injection of CO_2 for sequestration beneath the seabed of the North Sea has been taking place since 1996, and based on published reports, the CO_2 has been readily tracked in the subsurface using geophysical techniques and the process has been safe and effective. About one million metric tonnes per year are being injected at a sub-seabed depth of 3,300 feet under a caprock about 260 feet thick, comparable to shale caprocks in the Illinois Basin. I would conclude from this experience with CO_2, and from industry experience with geological storage of natural gas, that we should proceed with large-scale (one million tons/year to one million tons over three to four years) tests of geological carbon sequestration for further evaluation of reservoirs and caprocks as they vary in different regions of the country. These projects need to be well funded and designed to build on the technical experience I have just described.

To establish public confidence, all the regional partnerships have been carrying out public outreach activities and have been integrating environmental monitoring into their small-scale field testing of CO_2 injection during Phase II. For our Illinois Basin region, this monitoring has been the largest single budget item in our Phase II project, and appropriately so. As we move to the upcoming larger-scale tests, we need to invest even more into education, outreach, and, especially, environmental monitoring to ensure public confidence. Our experience to date, very much informed by the public meetings we have held with regard to the two FutureGen finalist sites in Illinois, has been that openness and transparency are essential to the process of gaining public trust. Yes, we are putting something new into the subsurface. Yes, there are small and difficult-to-quantify risks, such as slow leakage, involved in carrying out any such effort. But, yes, we are working diligently and in the most open way possible to investigate the geology of sequestration, and I believe that the geologic framework has the capacity and the security that we require to make sequestration a viable carbon management strategy. I also believe, however, that some budget figures that I have seen for FY08 and FY09 are inadequate to fully execute and monitor these critical large-scale tests in diverse geological settings around the U.S. I trust that this subcommittee and the Full Committee on Science and Technology will have the opportunity to review those allocations and give priority to the Phase III Regional Partnership Program's large-scale testing, among other important sequestration programs that benefit from the investments made to date in technology and expertise by the Department of Energy.

In summary, I would suggest to the Subcommittee that we are beginning to have a substantive understanding of the geological capacity for carbon sequestration, especially based on research over the last two to five years in the U.S. and internationally. Advanced coal technologies including coal gasification for electricity production, coal to synthetic natural gas, and coal to liquid fuels will depend on geological sequestration capacity to directly manage their CO_2 emissions. The need for such management has been made all the more evident by the growing concern over climate change as embodied in the assessments released by the Intergovernmental Panel on Climate Change (IPCC) and other groups since February of this year. While we are advancing sequestration technology, we must also address issues of long-term liability for sequestration projects, legal access to subsurface pore space, and issues of who will bear the costs of sequestration and how those costs will be distributed. Some of these issues are beginning to be articulated, but it is unlikely that these issues, or the testing of advanced coal technologies combined with carbon sequestration, can be addressed without unprecedented public-private collaboration. I urge this subcommittee to facilitate that process as we look forward to implementing advanced coal technologies incorporating geological carbon sequestration as a preferred and routine approach to coal utilization.

BIOGRAPHY FOR ROBERT J. FINLEY

Robert J. Finley is the Director of the Energy and Earth Resources Center at the Illinois State Geological Survey, Champaign, Illinois. He joined the Illinois Survey in February 2000 after serving as Associate Director at the Bureau of Economic Geology, The University of Texas at Austin. Rob's area of specialization is fossil energy resources. His work has ranged from large-scale resource assessment, addressing hydrocarbon resources at national and State scales, to evaluation of specific fields and reservoirs for coal, oil, and natural gas. He is currently heading a regional carbon sequestration partnership in the Illinois Basin aimed at addressing concerns with geological carbon management. Rob has served on committees of the National Petroleum Council, the American Association of Petroleum Geologists, the National Research Council, the Stanford Energy Modeling Forum, and the U.S. Potential Gas Committee. He has taught aspects of energy resource development since 1986 to numerous clients domestically and overseas in Venezuela, Brazil, South Africa, and Australia, among other countries. Rob holds a Ph.D. in geology from the University of South Carolina; he is currently also an Adjunct Professor in the Department of Geology, University of Illinois at Urbana-Champaign.

Chairman LAMPSON. Thank you, Dr. Finley. Mr. Rencheck.

STATEMENT OF MR. MICHAEL W. RENCHECK, SENIOR VICE PRESIDENT, ENGINEERING, PROJECTS AND FIELD SERVICES, AMERICAN ELECTRIC POWER

Mr. RENCHECK. Good afternoon, Mr. Chairman and Members of the Committee. Thank you for inviting me to participate in this meeting.

American Electric Power is one of the Nation's largest electricity utilities, with more than five million retail customers in 11 States. We are also one of the Nation's largest power generators, with more than 38,000 megawatts of generating capacity from a diverse fleet. In a particular note for today, AEP is one of the largest coal-fired electric generators in the U.S., and we have implemented a portfolio of voluntary actions to reduce, avoid, and offset greenhouse gases during the past decade.

Coal generates over 50 percent of the electricity used in the United States, and is used extensively worldwide. As demand for electricity increases significantly, coal use will increase as well. In the future, coal-fired electric generation must be zero-emission or close to it. This will be achieved through new technologies that are being developed today, but are not yet proven or commercially available.

Like most companies in our sector, AEP needs new generation. We are investing in new clean coal technology that will enable AEP and our industry to meet the challenge of reducing greenhouse gases for the long-term. This includes plans to build two new integrated gasification combined cycle units, IGCC, and two state-of-the-art ultrasupercritical units. These will be the first new generation of ultrasupercritical and IGCC units deployed in the United States. AEP is also taking a lead role of commercializing carbon capture technology for use on new generation, and more importantly, for use on existing generation as a retrofit.

We signed a memorandum of understanding also for post-combustion capture technology using Alstom's chilled ammonia system. Starting with a commercial performance verification project in mid to late 2008 in West Virginia, a project that will also include storage of the carbon dioxide in a saline aquifer, we will move to the first commercial sized project at one of our 450-megawatt plants at our Northeastern Unit in Oklahoma in 2011. This would capture about 1.5 million metric tons of CO_2 per year, which will be used for enhanced oil recovery.

We are also working with Babcock and Wilcox to develop its oxy-coal combustion technology, through development of a 30-megawatt thermal pilot plant at its Barberton, Ohio facility in 2007. Oxy-coal combustion forms a concentrated CO_2 post-combustion gas that can be stored without additional post-combustion gas processing equipment. We are hoping to bring this technology from the drawing board to commercial scale early in the next decade.

Retrofitting our existing fleet to ensure carbon capture will be neither easy nor inexpensive, and AEP is very comfortable leading the way. We have a long and impressive list of technological firsts that we achieved during our first hundred years of existence, but we have identified one very important caveat during our century of technological achievement and engineering excellence. Proving technology to be commercially viable and having that technology ready for widespread commercial use are two very different things. It takes time to develop off-the-shelf commercial offerings for new technology.

AEP is not calling for an indefinite delay in the enactment of mandatory climate change legislation until the advanced technology, such as carbon capture and storage, is developed. However, as the requirements become more stringent during the next ten to twenty years, and we move beyond the availability of current technology to deliver those reductions, it is essential that requirements for deeper reductions allow sufficient time for the demonstration and commercialization of these advanced technologies.

How can you help? It is also important to establish public funding, as well as incentives for private funding, for the development of commercially viable technology solutions, as well as providing the legal and the regulatory framework to facilitate this development. AEP believes that the IGCC and carbon capture and storage technologies need to be advanced, but the building of an IGCC and the timely development of commercially viable carbon capture and sequestration technologies will require additional public funding.

AEP and others in our sectors have already invested heavily into research and early development of technologies that may eventually be commercially viable solutions to capture and store greenhouse gas emissions. For this reason, separate investment tax credits are needed to facilitate both the construction of IGCC plants now, and the development of CCS technologies for future use.

American industry has long been staffed by excellent problem solvers. I am confident we will be able to develop the technologies to efficiently address emissions of greenhouse gases in an increasingly cost-effective manner. We have the brainpower. We need time, funding assistance, and the legal or regulatory support.

Thank you.

[The prepared statement of Mr. Rencheck follows:]

PREPARED STATEMENT OF MICHAEL W. RENCHECK

Summary of Testimony

American Electric Power (AEP) is one of the Nation's largest electricity generators with over five million retail consumers in 11 states. AEP has a diverse generating fleet—coal, nuclear, hydroelectric, gas, oil and wind. But of particular note, AEP is one of the largest coal-fired electricity generators in the U.S.

Over the last 100 years, AEP has led the Industry in developing and deploying new technologies beginning with the first high voltage transmission lines at 345 kilovolt (kV) and 765 kV to new and more efficient coal power plants starting with the large central station power plant progressing to super-critical and ultra-supercritical power plants. During the past decade, American Electric Power has implemented a portfolio of voluntary actions to reduce, avoid or offset greenhouse gases (GHG). During 2003–05, AEP reduced its GHG emissions by 31 million metric tons of CO_2 by planting trees, adding wind power, increasing power plant generating efficiency, and retiring less-efficient units among other measures.

We also continue to invest in new clean coal technology that will enable AEP and our industry to meet the challenge of reducing GHG emissions for the long-term.

This includes plans to build two new integrated gasification combined cycle (IGCC) plants and two state-of-the-art, ultra-super-critical plants. These will be the first of the new generation of ultra-super-critical plants in the U.S. AEP plans to take a lead role in commercializing carbon capture technology. We signed a memorandum of understanding (MOU) with Alstom for post-combustion carbon capture technology using its chilled ammonia system. Starting with a "commercial performance verification" project in mid to late 2008 in West Virginia, we would move to the first commercial-sized project at one of our 450-megawatt coal-fired units at Northeastern Plant in Oklahoma by late 2011. This would capture about 1.5 million metric tons of CO_2 a year, which will be used for enhanced oil recovery. Additionally, we signed a memorandum of understanding with Babcock and Wilcox to participate in a oxy-coal pilot project. This project will be used to refine the process and eventually determine if the combustion technology can be retrofit into existing plants.

Over all, AEP supports the adoption of an economy-wide cap-and-trade type GHG reduction program that is well thought-out, achievable, and reasonable. We believe legislation can be crafted that does not impede AEP's ability to provide reliable, reasonably priced electricity to support the economic well-being of our customers, and includes mechanisms that foster international participation and avoids harming the U.S. economy. A pragmatic approach for phasing in GHG reductions through a cap-and-trade program coincident with developing technologies to support these reductions will be critical to crafting achievable and reasonable legislation.

The development of these technologies will be facilitated by and are dependent on public funding through tax credits and similar incentives. AEP is doing its part as we aggressively explore the viability of this technology in several first-of-a-kind commercial projects. We are advancing the development of IGCC and other necessary technologies as we seek to build two IGCC plants and two state-of-the-art ultra-super-critical power plants. 1n addition, we are a founding member of FutureGen, a ground-breaking public-private collaboration that aims squarely at making near-zero-emissions coal-based energy a reality. Simply put, however, commercially engineered and available technology to capture and store CO_2 does not economically exist today and we strongly recommend that any legislation you adopt reflect this fact.

Testimony

Good morning Mr. Chairman and distinguished Members of the House Committee on Science and Technology, Subcommittee on Energy and Environment.

Thank you for inviting me here today. Thank you for this opportunity to offer the views of American Electric Power (AEP) and for soliciting the views of our industry and others on climate change technologies.

My name is Mike Rencheck, Senior Vice President—Engineering, Projects & Field Services of American Electric Power (AEP). Headquartered in Columbus, Ohio, we are one of the Nation's largest electricity generators—with over 36,000 megawatts of generating capacity—and serve more than five million retail consumers in 11 states in the Midwest and south central regions of our nation. AEP's generating fleet employs diverse sources of fuel—including coal, nuclear, hydroelectric, natural gas, and oil and wind power. But of particular importance for the Committee Members here today, AEP uses more coal than any other electricity generator in the Western hemisphere.

AEP's Technology Development

Over the last 100 years, AEP has been an industry leader in developing and deploying new technologies beginning with the first high voltage transmission lines at 345 kilovolt (kV) and 765kV, to new and more efficient coal power plants starting with the large central station power plant, progressing to super-critical and ultra-super-critical powers plants. We are continuing that today. We have implemented 14 selective catalytic reactors (SCRs), and 10 Flue Gas Desulphurization units, with others currently under construction, and we are a leader in developing and deploying mercury capture and monitoring technology. In addition, we continue to invest in new clean coal technology plants and R&D that will enable AEP and our industry to meet the challenge of significantly reducing GHG emissions in future years. For example, AEP is working to build two new generating plants using Integrated Gasification Combined Cycle (IGCC) technology in Ohio and West Virginia, as well as two highly efficient new generating plants using the most advanced (e.g., ultra-super-critical) pulverized coal combustion technology in Arkansas and Oklahoma. We are also providing a leading role in the FutureGen project, which once completed, will be the world's first near-zero CO_2 emitting commercial scale coal-fueled power plant. We are also working to progress specific carbon capture and storage technology.

AEP's Major New Initiative to Reduce GHG Emissions

In March, AEP announced several major new initiatives to reduce AEP's GHG emissions and to advance the commercial application of carbon capture and storage technology and Oxy-coal combustion. Our company has been advancing technology for the electric utility industry for more than 100 years. AEP's recent announcement continues to build upon this heritage. Technology development needs are often cited as an excuse for inaction. We see these needs as opportunities for action.

AEP has signed a memorandum of understanding (MOU) with Alstom, a worldwide leader in equipment and services for power generation, for post-combustion carbon capture technology using Alstom's chilled ammonia system. It will be installed at our 1,300-megawatt Mountaineer Plant in New Haven, West Virginia as a "30-megawatt (thermal) commercial performance verification" project in mid to late 2008 and it will capture up to 100,000 metric tons of carbon dioxide (CO_2) per year. Once the CO_2 is captured, we will store it. The Mountaineer site has an existing deep saline aquifer injection well previously developed in conjunction with the Department of Energy (DOE) and Battelle. Working with Battelle and with continued DOE support, we will use this well (and develop others) to store and further study CO_2 injection into deep geological formations.

Following the completion of commercial verification at Mountaineer, AEP plans to install Alstom's system on one of the 450-megawatt coal-fired units at its Northeastern Plant in Oologah, Oklahoma, as a first-of-a-kind commercial demonstration. The system is expected to capture approximately 1.5 million metric tons of CO_2 per year and be operational in late 2011. The CO_2 captured at Northeastern Plant will be used for enhanced oil recovery.

AEP has also signed an MOU with Babcock and Wilcox to pursue the development of Oxy-coal combustion that uses oxygen in lieu of air for combustion. The Oxy-coal combustion forms a concentrated CO_2 post combustion gas that can be stored without additional post combustion capture processes. AEP is working with B&W on a "30-megawatt (thermal) pilot project." The results are due in mid-2007 and then these results will be used to study the feasibility of a scaled up 100–200MW (electric) demonstration. The CO_2 from the demonstration project would be captured and stored in a deep saline geologic formation or used for enhanced oil recovery application.

In March, AEP also voluntarily committed to achieve an additional five million tons of GHG reductions annually beginning in 2011. We will accomplish these reductions through a new AEP initiative that will add another 1,000MW of purchased wind power into our system, substantially increase our forestry investments (in addition to the 62 million trees we have planted to date), as well as invest in domestic offsets, such as methane capture from agriculture, mines, and landfills.

AEP has also implemented efficiency improvements at several plants in its existing generation fleet. These improvements include new turbine blading, valve replacements, combustion tuning, and installation of variable speed drives on rotating equipment. Such improvements are currently reported through the Department of Energy's 1605 (b) program to the extent they produce creditable reductions in greenhouse gas emissions. However, we are limited in the efficiency improvements we can make due to the ambiguities in the existing New Source Review program, and support further clarification and reform of this program to encourage efficiency improvements.

AEP Perspectives on a Federal GHG Reduction Program

While AEP has done much, and will do much more, to mitigate GHG emissions from its existing sources, we also support the adoption of an economy-wide cap-and-trade type GHG reduction program that is well thought-out, achievable, and reasonable. Although today I intend to focus on the need for the development and deployment of commercially viable technologies to address climate change and not on the specific policy issues that must be addressed, AEP believes that legislation can be crafted that does not impede AEP's ability to provide reliable, reasonably priced electricity to support the economic well-being of our customers, and includes mechanisms that foster international participation and avoid creating inequities and competitive issues that would harm the U.S. economy. AEP supports reasonable legislation, and is not calling for an indefinite delay until advanced technology to support carbon capture and storage (CCS), among others, is developed. However, as the requirements become more stringent during the next ten to twenty years, and we move beyond the ability of current technology to deliver those reductions, it is essential that requirements for deeper reductions coincide with the commercialization of advanced technologies.

Phased-in Timing and Gradually Increasing Level of Reductions Consistent With Technology Development That Is Facilitated by Public Funding

As a practical matter, implementing climate legislation is a complex undertaking that will require procedures for measuring, verifying, and accounting for GHG emissions, as well as for designing efficient administration and enforcement procedures applicable to all sectors of our economy. Only a pragmatic approach with achievable targets, supported by commercial technology, and reasonable timetables—that does not require too many reductions within too short a time period—will succeed.

AEP also believes that the level of emissions reductions and timing of those reductions under a federal mandate must keep pace with developing technologies for reducing GHG emissions from new and existing sources. The technologies for effective carbon capture and storage from coal-fired facilities are developing, but are not commercially engineered to meet production needs, and cannot be artificially accelerated through unrealistic reduction mandates.

While AEP and other companies have successfully lowered their average emissions and emission rates during this decade, further substantial reductions will require the wide-scale commercial availability of new clean coal technologies. AEP believes that the electric power industry can potentially manage much of the expected economic (and CO_2 emissions) growth over the course of the next decade (2010–2020) through aggressively deploying renewable energy, achieving further gains in supply and demand-side energy efficiency, and implementing new emission offset projects. As stated above, AEP supports reasonable legislation, and is not calling for an indefinite delay of GHG reduction obligations until advanced clean coal technology is developed. However, as the reduction requirements become more stringent, and move beyond the ability of current technologies to deliver those reductions, it is important that those stringent requirements coincide with the commercialization of advanced technology. This includes the next generation of low- and zero-emitting technologies.

Significantly, today's costs of new clean coal technologies with carbon capture and storage are much more expensive than current coal-fired technologies. For example, carbon capture and storage using current inhibited monoethanolamine (MEA) technology is expected to increase the cost of electricity from a new coal fired power plant by about 60–70 percent. Even the newer chilled ammonia carbon capture technology we plan to deploy on a commercial sized scale by 2012 at one of our existing coal-fired units will result in significantly higher costs.

Additionally the MEA technology has limitations under existing plant retrofit conditions. CO_2 capture requires a large volume of steam to regenerate the amine used to capture the CO_2. Review of several of our existing PC units indicates they can only supply enough steam from the power generation cycle to regenerate the amine necessary to capture about 50 percent of the CO_2, without jeopardizing the steam cycle.

It is only through the steady and judicious advancement of these applications during the course of the next decade that we can start to bring these costs down, in order to avoid substantial electricity rate shocks and undue harm to the U.S. economy.

IGCC technology, for example, integrates two proven processes—coal gasification and combined cycle power generation—to convert coal into electricity more efficiently and cleanly than any existing uncontrolled power plant can. Not only is it cleaner and more efficient than today's installed power plants, but IGCC has the potential to be retrofitted in the future for carbon capture at a lower capital cost and with less of an energy penalty than traditional power plant technologies, but only after the technology has been developed and proven. Our IGCC plants will incorporate the space and layout for the addition of components to capture CO_2 for sequestration.

Our IGCC plants will be among the earliest, if not the first, deployments of large-scale IGCC technology. The cost of constructing these plants will be high, resulting in a cost of generated electricity that would be twenty to thirty percent greater than that from pulverized coal (PC) combustion technology. As more plants are built, the costs of construction are expected to come into line with the cost of PC plants.

To help bridge the cost gap and move IGCC technology down the cost curve, there is a need for continuation and expansion of the advanced coal project tax credits that were introduced by the *Energy Policy Act of 2005.* All of the available tax credits for IGCC projects using bituminous coal were allocated to only two projects during the initial allocation round in 2006. More IGCC plants are needed to facilitate this technology. AEP believes an additional one billion dollars of section 48A (of the Internal Revenue Code) tax credits are needed, with the bulk of that dedicated to IGCC projects without regard to coal type.

Along with an increase in the amount of the credits, changes are needed in the manner in which the credits are allocated. Advanced coal project credits should be allocated based on net generating capacity and not based upon the estimated gross nameplate generating capacity of projects. Allocation based upon gross, rather than net, generating capacity potentially rewards less efficient projects, which is antithetical to the purpose of advanced coal project tax incentives. AEP also believes that the Secretary of Energy should be delegated a significant role in the selection of IGCC projects that will receive tax credits.

On a critical note, the inclusion of carbon capture and sequestration equipment must not be a prerequisite for the allocation of these additional tax credits due to the urgent need for new electric generating capacity in the U.S. AEP also believes that this requirement is premature and self-defeating to advancing IGCC technology. The addition would require yet-to-be developed technology and/or would cause the projected cost of a project to increase significantly, making it that much more difficult for a public utility commission to approve.

AEP also believes that additional tax incentives are needed to spur the development and deployment of greenhouse gas capture and sequestration equipment for all types of coal fired generation. We suggest that additional tax credits be established to offset a significant portion of the incremental cost of capturing and sequestering CO_2. These incentives could be structured partly as an investment tax credit, similar to that in section 48A (of the Internal Revenue Code), to cover the up-front capital cost, and partly as a production tax credit to cover the associated operating costs.

In summary, AEP recommends a pragmatic approach for phasing in GHG reductions through a cap-and-trade program coincident with developing technologies to support these reductions.

Technology Is the Answer to Climate Change

The primary human-induced cause of global warming is the emission of CO_2 arising from the burring of fossil fuels. Put simply, our primary contribution to climate change is also what drives the global economic engine.

Changing consumer behavior by buying efficient appliances and cars, by driving less, and other similar steps, is helping to reduce the growth of GHG emissions. However, these steps will never be enough to significantly reduce CO_2 emissions from the burning of coal, oil and natural gas. Such incremental steps, while important, will never be sufficient to stabilize greenhouse gases concentrations in the atmosphere at a level that is believed to be capable of preventing dangerous human-induced interference with the climate system, as called for in the U.S.-approved U.N. Framework Convention on Climate Change (Rio agreement). For that, we need major technological advances to effectively capture and store CO_2. The Congress and indeed all Americans must come to recognize the gigantic undertaking and significant sacrifices that this enterprise is likely to require.

CCS should not be mandated until and unless it has been demonstrated to be effective and the costs have significantly dropped so that it becomes commercially engineered and available on a widespread basis. Until that threshold is met, it would be technologically unrealistic and economically unacceptable to require the widespread installation of carbon capture equipment. The use of deep saline geologic formations as primary long-term CO_2 storage locations has not yet been sufficiently demonstrated. There are no national standards for permitting such storage reservoirs; there are no widely accepted monitoring protocols; and the standards for liability are unknown (as well as whether federal or State laws would apply). In addition, who owns the rights to these deep geologic reservoirs remains a question.

Outstanding technical questions for CO_2 storage include: What is the number of injector wells needed? What is the injector well lifespan? What is the injector well proximity to other wells? What measurement, monitoring, and verification of storage in the geologic reservoirs is needed? What is the time span of post-injection monitoring? Much work needs to be done to ensure that the potential large and rapid scale-up in CCS deployment will be successful.

Underscoring these realities, industrial insurance companies point to this lack of scientific data on CO_2 storage as one reason they are disinclined to insure early projects. In a nutshell, the institutional infrastructure to support CO_2 storage does not yet exist and will require time to develop. In addition, application of today's CO_2 capture technology would significantly increase the cost of an IGCC or a new efficient pulverized coal plant, calling into serious question regulatory approval for the costs of such a plant by State regulators. Further, recent studies sponsored by the Electric Power Research Institute (EPRI) suggest that application of today's CO_2 capture technology would increase the cost of electricity from an IGCC plant by 40 to 50 percent, and boost the cost of electricity from a conventional pulverized coal plant by 60 to 70 percent, which would again jeopardize State regulatory approval for the costs of such plants.

Despite these uncertainties, I believe that we must aggressively explore the viability of CCS technology in several first-of-a-kind commercial projects. AEP is committed to help lead the way, and to show how this can be done.

As described earlier in this testimony, AEP will install carbon capture controls on two existing coal-fired power plants, the first commercial use of this technology, as part of our comprehensive strategy to reduce, avoid or offset GHG emissions.

AEP is also building two state-of-the-art advanced ultra-super-critical power plants in Oklahoma and Arkansas. These will be the first of the new generation of ultra-super-critical plants in the U.S. The more efficient turbine cycle on these ultra-super-critical units results from increased steam temperatures (greater than 1100 °F). This improved efficiency reduces fuel (coal) consumption and thereby reduces emissions. The long-term goal for ultra-super-critical technology is to develop "super alloys" which can withstand operating temperatures of 1400 °F. This increased steam temperature will improve efficiency by about 20 percent relative to today's super-critical units that are operating in the 1000 °F to 1050 °F range.

AEP is also advancing the development of IGCC technology. IGCC represents a major breakthrough in our work to improve the environmental performance of coal-based electric power generation. AEP is in the process of permitting and designing two of the earliest commercial scale IGCC plants in the Nation. Construction of the IGCC plants will start once traditional rate recovery is approved.

AEP is also a founding member of FutureGen, a ground-breaking public-private collaboration that aims squarely at making near-zero-emissions coal-based energy a reality.

FutureGen is a $1.5 billion, 10-year research and demonstration project. It is on track to create the world's first coal-fueled, near-zero emission electricity and hydrogen plant with the capability to capture and sequester at least 90 percent of its carbon dioxide emissions.

As an R&D plant, FutureGen will stretch—and indeed create—the technology envelope. Within the context of our fight to combat global climate change, FutureGen has a truly profound mission—to validate the cost and performance baselines of a fully integrated, near zero-emission coal-fueled power plant.

The design of the FutureGen plant is already underway, and we are making great progress. The plant will be on-line early in the next decade. By the latter part of that decade, following on the advancements demonstrated by AEP, FutureGen, and other projects, CCS technology should become a commercial reality.

It is when these technologies are commercially demonstrated, and only then, that commercial orders will be placed on a widespread basis to implement CCS at coal-fueled power plants. That is, roughly around 2020. Widespread deployment assumes that a host of other important issues have been resolved, and there is governmental and public acceptance of CCS as the proven and safe technology that we now believe it to be. AEP supports rapid action on climate change including the enactment of well thought-out and achievable legislation so that our nation can get started on dealing with climate change. However, the development of technology must coincide with any increase in the stringency of the program.

A huge challenge that our society faces over the remainder of this century is how we will reduce the release of GHG emissions from fossil fuels. This will require nothing less than the complete re-engineering of the entire global energy system over the next century. The magnitude of this task is comparable to the industrial revolution, but for this revolution to be successful, it must stimulate new technologies and new behaviors in all major sectors of the world economy. The benefits of projects like FutureGen and the ones AEP is pursuing will apply to all countries blessed with an abundance of coal, not only the United States, but also nations like China and India.

In the end, the only sure path to stabilizing GHG concentrations over the long-term is through the development and utilization of advanced technologies. And we must do more than simply call for it. Our nation must prepare, inspire, guide, and support our citizens and the very best and the brightest of our engineers and scientists; private industry must step up and start to construct the first commercial plants; and our country must devote adequate financial and technological resources to this enormous challenge. AEP is committed to being a part of this important process, and to helping you achieve the best outcome at the most reasonable cost and timelines possible. Thank you again for this opportunity to share these views with you.

AMERICAN ELECTRIC POWER

NEWS from AEP

MEDIA CONTACT:
Pat D. Hemlepp
Director, Corporate Media Relations
614/716-1620

ANALYSTS CONTACT:
Julie Sloat
Vice President, Investor Relations
614/716-2885

FOR IMMEDIATE RELEASE

AEP TO INSTALL CARBON CAPTURE ON TWO EXISTING POWER PLANTS; COMPANY WILL BE FIRST TO MOVE TECHNOLOGY TO COMMERCIAL SCALE

As climate policy advances, 'it's time to advance technology for commercial use,' CEO says

COLUMBUS, Ohio, March 15, 2007 – American Electric Power (NYSE:AEP) will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.

The first project is expected to complete its product validation phase in 2008 and begin commercial operation in 2011.

"AEP has been the company advancing technology for the electric utility industry for more than 100 years," said Michael G. Morris, AEP chairman, president and chief executive officer. "This long heritage, the backbone of our company's success, makes us very comfortable taking action on carbon emissions and accelerating advancement of the technology. Technology development needs are often cited as an excuse for inaction. We see these needs as an opportunity for action.

"With Congress expected to take action on greenhouse gas issues in climate legislation, it's time to advance this technology for commercial use," Morris said. "And we will continue working with Congress as it crafts climate policy. It is important that the U.S. climate policy be well thought out, establish reasonable targets and timetables, and include mechanisms to prevent trade imbalances that would damage the U.S. economy."

Morris will discuss AEP's plans for carbon capture during a presentation today at the Morgan Stanley Global Electricity & Energy Conference in New York. A live webcast of the presentation to an audience of investors will begin at 12:10 p.m. EDT and can be accessed through the Internet at http://www.aep.com/go/webcast. The webcast will also be available after the event. Visuals used in the presentation will be available at http://www.aep.com/investors/present.

AEP has signed a memorandum of understanding (MOU) with Alstom, a worldwide leader in equipment and services for power generation and clean coal, for post-combustion carbon capture technology using Alstom's Chilled Ammonia Process. This technology, which is being piloted this summer by Alstom on a 5-megawatt (thermal) slipstream from a plant in Wisconsin, will first be installed on AEP's 1300-megawatt Mountaineer Plant in New Haven, W.Va., as a 30-megawatt (thermal) product validation in mid-2008 where up to 100,000 metric tons of carbon dioxide (CO_2) will be captured per year. The captured CO2 will be designated for geological storage in deep saline aquifers at the site. Battelle Memorial Institute will serve as consultants for AEP on geological storage.

Following the completion of product validation at Mountaineer, AEP will install Alstom's system on one of the 450-megawatt (electric) coal-fired units at its Northeastern Station in Oologah, Okla. Plans are for the commercial-scale system to be operational at Northeastern Station in late 2011. It is expected to capture about 1.5 million metric tons of CO_2 a year. The CO_2 captured at Northeastern Station will be used for enhanced oil recovery.

Alstom's system captures CO_2 by isolating the gas from the power plant's other flue gases and can significantly increase the efficiency of the CO_2 capture process. The system chills the flue gas, recovering large quantities of water for recycle, and then utilizes a CO_2 absorber in a similar way to absorbers used in systems that reduce sulfur dioxide emissions. The remaining low concentration of ammonia in the clean flue gas is captured by cold-water wash and returned to the absorber. The CO_2 is compressed to be sent to enhanced oil recovery or storage.

In laboratory testing sponsored by Alstom, EPRI and others, the process has demonstrated the potential to capture more than 90 percent of CO_2 at a cost that is far less expensive than other carbon capture technologies. It is applicable for use on new power plants as well as for the retrofit of existing coal-fired power plants.

AEP has signed an MOU with The Babcock & Wilcox Company (B&W), a world leader in steam generation and pollution control equipment design, supply and service since 1867, for a feasibility study of oxy-coal combustion technology. B&W, a subsidiary of McDermott International, Inc. (NYSE:MDR), will complete a pilot demonstration of the technology this summer at its 30-megawatt (thermal) Clean Environment Development Facility in Alliance, Ohio.

Following this demonstration, AEP and B&W will conduct a retrofit feasibility study that will include selection of an existing AEP plant site for commercial-scale installation of the technology and cost estimates to complete that work. Once the retrofit feasibility study is completed, detailed design engineering and construction estimates to retrofit an existing AEP plant for commercial-scale CO_2

capture will begin. At the commercial scale, the captured CO_2 will likely be stored in deep geologic formations. The plant, with oxy-coal combustion technology, is expected to be in service in the 2012-2015 time frame.

B&W, in collaboration with American Air Liquide Inc., has been developing oxy-coal combustion, a technology that utilizes pure oxygen for the combustion of coal. Current generation technologies use air, which contains nitrogen that is not utilized in the combustion process and is emitted with the flue gas. By using pure oxygen, oxy-coal combustion excludes nitrogen and leaves a flue gas that is a relatively pure stream of carbon dioxide that is ready for capture and storage. B&W's and Air Liquide's collaborative work on oxy-coal combustion began in the late 1990s and included pilot-scale development at B&W's facilities with encouraging results, burning both bituminous and sub-bituminous coals.

The oxy-coal combustion process, as envisioned, uses a standard, cryogenic air separation unit to provide relatively pure oxygen to the combustion process. This oxygen is mixed with recycled flue gas in a proprietary mixing device to replicate air, which may then be used to operate a boiler designed for regular air firing. The exhaust gas, consisting primarily of carbon dioxide, is first cleaned of traditional pollutants, then compressed and purified before storage. B&W, working with Air Liquide, can supply the equipment, technology and control systems to construct this new value chain, either as a new application or as a retrofit to an existing unit.

The Alstom technology provides a post-combustion carbon capture system that is suitable for use in new plants as well as for retrofitting to existing plants. It requires significantly less energy to capture CO_2 than other technologies currently being tested.

The B&W technology provides a pre-combustion boiler conversion option for existing plants that promotes the creation of a pure CO_2 stream in the flue gas.

Both pre- and post-combustion technologies will be important for companies facing decisions on carbon reduction from the wide variety of coal-fired boiler designs currently in use.

AEP anticipates seeking funding from the U.S. Department of Energy to help offset some of the costs of advancing these technologies for commercial use. The company will also work with utility commissions, environmental regulators and other key constituencies in states that have jurisdiction over the plants selected for retrofit to determine appropriate cost recovery and the impact on customers.

"We recognize that these projects represent a significant commitment of resources for AEP, but they are projects that will pay important dividends in the future for our customers and shareholders," Morris said. "Coal is the fuel used to generate half of the nation's electricity; it fuels about 75 percent of AEP's generating fleet. By advancing carbon capture technologies into commercial use, we are taking an important step to ensure the continued and long-term viability of our existing generation, just as we did when we were the first to begin a comprehensive, system-wide retrofit program for sulfur dioxide and nitrogen oxide emissions controls. We have completed the sulfur dioxide and nitrogen oxide retrofits on more than two-thirds of the capacity included in the program and we are on schedule to complete all retrofits by shortly after the end of the decade.

"By being the first to advance carbon capture technology, we will be well-positioned to quickly and efficiently retrofit additional plants in our fleet with carbon capture systems while avoiding a potentially significant learning curve."

AEP has led the U.S. electric utility industry in taking action to reduce its greenhouse gas emissions. AEP was the first and largest U.S. utility to join the Chicago Climate Exchange (CCX), the world's first and North America's only voluntary, legally binding greenhouse gas emissions reduction and trading program. As a member of CCX, AEP committed to gradually reduce, avoid or offset its greenhouse gas emissions to 6 percent below the average of its 1998 to 2001 emission levels by 2010. Through this commitment, AEP will reduce or offset approximately 46 million metric tons of greenhouse gas emissions by the end of the decade.

AEP is achieving its greenhouse gas reductions through a broad portfolio of actions, including power plant efficiency improvements, renewable generation such as wind and biomass co-firing, off-system greenhouse gas reduction projects, reforestation projects and the potential purchase of emission credits through CCX.

American Electric Power is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 36,000 megawatts of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765 kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and the performance of AEP's generating plants; AEP's ability to recover regulatory assets and stranded costs in connection with deregulation; AEP's ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; AEP's ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp. and related matters); AEP's ability to constrain operation and maintenance costs; the economic climate and growth in AEP's service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; AEP's ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities; changes in the creditworthiness of the counterparties with whom AEP has contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the performance of AEP's pension and other postretirement benefit plans; prices for power that AEP generates and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

BACKGROUND: American Electric Power's Actions to Address Climate Change

GHG Reduction Commitment

American Electric Power (AEP) was the first and largest U.S. utility to join the Chicago Climate Exchange (CCX) and make a legally binding commitment to gradually reduce or offset its greenhouse gas emissions to 6 percent below the average of 1998-2001 emission levels by 2010.

As a founding member of CCX, AEP committed in 2003 to reduce or offset its emissions gradually to 4 percent below the average of 1998-2001 emission levels by 2006 (1 percent reduction in 2003, 2 percent in 2004, 3 percent in 2005 and 4 percent in 2006). In August 2005, AEP expanded and extended its commitment to a 6 percent reduction below the same baseline by 2010 (4.25 percent in 2007, 4.5 percent in 2008, 5 percent in 2009 and 6 percent in 2010). Through this commitment, AEP expects to reduce or offset approximately 46 million metric tons of greenhouse gas emissions.

Operational Improvements

AEP has been able to reduce its carbon dioxide (CO_2) emissions by improving plant efficiency for its fossil-fueled plants through routine maintenance and investments like turbine blade enhancements (installing new turbine blades) and steam path replacements that improve the overall heat rate of a plant and, in turn, reduce CO_2 emissions. A one-percent improvement in AEP's overall fleet efficiency can reduce the company's greenhouse gas emissions by 2 million metric tons per year.

AEP has also reduced its CO_2 emissions by improving the performance and availability of its nuclear generation. AEP's D.C. Cook Nuclear Plant in Michigan set plant records for generation and capacity factor in 2005. The plant had a capacity factor (energy generated as compared to the maximum possible) of 96.8 percent in 2005 and generated 17,471gigawatt-hours (GWH) of electricity. Additionally, AEP will invest $45 million to replace turbine motors in one unit at D.C. Cook in 2006, which will increase that unit's output by 41 megawatts.

As a member of the US EPA's Sulfur Hexafluoride (SF6) Emissions Reduction Partnership for Electric Power Systems, AEP has significantly reduced emissions of SF6, an extremely potent greenhouse gas, from 1999 levels of 19,778 pounds (a leakage rate of 10 percent) to 2004 emissions of 1,962 pounds (a leakage rate of 0.5 percent).

Managing Forests and Agricultural Lands for Carbon Sequestration

To reduce carbon dioxide (CO_2) concentrations in the global atmosphere, AEP has invested more than $27 million in terrestrial sequestration projects designed to conserve and reforest sensitive areas and offset more than 20 million metric tons of CO_2 over the next 40 years. These projects include protecting nearly 4 million acres of threatened rainforest in Bolivia, restoring and protecting 20,000 acres of degraded or deforested tropical Atlantic rainforest in Brazil, reforesting nearly 10,000 acres of the Mississippi River Valley in Louisiana with bottomland hardwoods, restoring and protecting forest areas in the Sierra Madres of Guatemala, and planting trees on 23,000 acres of company-owned land.

Deploying Technology for Clean-Coal Generation

AEP is focused on developing and deploying new technology that will reduce the emissions, including greenhouse gas emissions, of future coal-based power generation. AEP announced in August 2004 its plans to build a commercial-scale Integrated Gasification Combined Cycle (IGCC) plants to demonstrate the viability of this technology for future use of coal in generating electricity. AEP has filed for regulatory approval in Ohio and West Virginia to build a 629-megawatt IGCC plant in each of these states. The plants are scheduled to be operational in the 2010 to 2011 timeframe and will be designed to accommodate retrofit of technology to capture and sequester CO_2 emissions.

Developing Technology for CO_2 Capture and Storage

AEP's Mountaineer Plant in New Haven, W.Va., is the site of a $4.2 million carbon sequestration research project funded by the U.S. Department of Energy, the Ohio Coal Development Office, and a consortium of public and private sector participants. Scientists from Battelle Memorial Institute lead this climate change mitigation research project, which is designed to obtain data required to better understand and test the capability of deep saline aquifers for storage of carbon dioxide emissions from power plants.

AEP is a member of the FutureGen Alliance, who, along with the Department of Energy, will build "FutureGen," a $1 billion, near-zero emission plant to produce electricity and hydrogen from coal while capturing and disposing of carbon dioxide in geologic formations.

Additionally, AEP funds research coordinated by the Massachusetts Institute of Technology Energy Laboratory and the Electric Power Research Institute that is evaluating the environmental impacts, technological approaches, and economic issues associated with carbon sequestration. The MIT research specifically focuses on efforts to better understand and reduce the cost of carbon separation and sequestration.

Renewable Energy and Clean Power

AEP strongly supports increased renewable energy sources to help meet our nation's energy needs. AEP is one of the larger generators and distributors of wind energy in the United States, operating 311 megawatts (MW) of wind generation in Texas. The company also purchases and distributes an additional 373.5 megawatts of wind generation from wind facilities in Oklahoma and Texas. Additionally, AEP operates 2,285 megawatts of nuclear generation and 884 megawatts of hydro and pumped storage generation.

More than 125 schools participate in AEP's "Learning From Light" and "Watts on Schools" programs. Through these programs, AEP partners with learning institutions to install 1 kW solar photovoltaic systems, and uses these systems to track energy use and demonstrate how solar energy is a part of the total energy mix. Similarly, AEP's "Learning From Wind" program installs small-scale wind turbines to provide wind power education and renewable energy research at educational institutions.

Biomass Energy

Until the company sold the plants in 2004, AEP co-fired biomass in 4,000 MW of coal-based power generation in the United Kingdom (Fiddler's Ferry and Ferry Bridge). AEP has been evaluating and testing biomass co-firing for its smaller coal-fired power plants in the United States to evaluate potential reductions in CO_2 emission levels.

Energy Conservation and Energy Efficiency

AEP is implementing "Energy Efficiency Plans" to offset 10 percent of the annual energy demand growth

in its Texas service territory. In 2003 alone, AEP invested more than $8 million to achieve over 47 million kilowatt-hours (kWH) of reductions from installation of energy efficiency measures in customers' homes and businesses. Total investments for the four-year program will exceed $43 million, achieving more than 247 million kWh of energy efficiency gains.

2005 EPA Climate Protection Award

In May 2005, the EPA selected AEP to receive a 2005 Climate Protection Award for demonstrating ingenuity, leadership and public purpose in its efforts to reduce greenhouse gases. EPA began the Climate Protection Awards program in 1998 to recognize outstanding efforts to project the earth's climate.

BIOGRAPHY FOR MICHAEL W. RENCHECK

Michael W. Rencheck is Senior Vice President—Engineering, Projects and Field Services and is responsible for engineering, regional maintenance and shop service organizations, projects and construction, and new generation development.

From June 2003 to December 2005, he was Senior Vice President—Engineering, Technical and Environmental Services. He was also President of AEP Pro Serv from November 2002 to May 2003.

He served as Senior Vice President—Engineering and Region Operations for Pro Serv from April to November 2002. Prior to that, he was Vice President—Strategic Business Improvement at AEP's D.C. Cook Nuclear Plant from October 2001 to March 2002 and Vice President—Nuclear Engineering at Cook from 1998 to 2001.

Previously, he served as Director—Nuclear Engineering and Projects at Florida Power Corp.'s Crystal River Nuclear Station in 1997–98. He was Director—System Engineering in 1997 and Manager—System Engineering from 1995 to 1997 at Public Service Electric & Gas Co. He held various technical and management positions at Duquesne light Company from 1983 to 1995.

Rencheck has a Master's degree in management and computer information systems from Robert Morris College in Coraopolis, Pa., and a Bachelor's degree in electrical engineering from Ohio Northern University in Ada, Ohio. He is a professional engineer (Arkansas, Indiana, Kentucky, Michigan, Ohio, Pennsylvania, Virginia and West Virginia) and a certified senior reactor operator.

Chairman LAMPSON. Thank you, Mr. Rencheck. Mr. Dalton.

STATEMENT OF MR. STUART M. DALTON, DIRECTOR, GENERATION, ELECTRIC POWER RESEARCH INSTITUTE

Mr. DALTON. Thank you, Mr. Chairman, thank you to the Committee, and thank you for having EPRI here for the testimony. For those of you that don't know, EPRI is a nonprofit R&D organization, with operational headquarters in California, but with principal operations also in Tennessee and in North Carolina.

I would like to summarize just a couple of brief points, and then elaborate briefly. Recent EPRI work shows that reduction of CO_2 from the electricity sector will require a portfolio of technologies of all sorts, not just capture and storage. Efficiency improvements, which we haven't talked about much yet today, includes post-generation and can be implemented in both new and existing plants. CO_2 capture and storage, which we have talked about, will be an important CO_2 reduction method, but there is no silver bullet technology, and it will not be easy or cheap.

Accelerated R&D is needed in all types of coals and technologies, as well as for large-scale storage of CO_2 to prove effectiveness. And finally, policy and research needs to match this accelerated approach to efficiency enhancements, CO_2 capture and storage.

To expand on these briefly, recent analytical work by EPRI estimates that in order to significantly reduce CO_2 from the electricity sector, the U.S. will need to improve efficiency of electric transmission, and use efficiency, renewables, nuclear, as well as improvements in coal and capture and storage, a lot of it is to the subject of today's hearing.

There is no single silver bullet, but there is a veritable arsenal of technology being developed worldwide that needs to be demonstrated and deployed. Multiple coal technologies with carbon capture and storage will need to be demonstrated across the range of U.S. applications. Our projects, and those of others, are that coal will continue to be used, and that we will need to optimize efficiency and CO_2 capture and storage as a major part of the overall CO_2 reduction program.

Existing and new plants can improve efficiency, and reduce CO_2 per megawatt-hour, per unit of power produced, by a variety of equipment and operational changes. Some of these can be accomplished through operational minor equipment changes. Some will require significant modifications in their equipment. All types of coal-based generation are capable of improving efficiency for new units. Significant programs are underway in the U.S. with regard to that. Over the next 20 years, we believe the improvements can achieve CO_2 reductions of up to 20 percent per megawatt-hour without additional CO_2 capture. The MIT Future of Coal report, the National Coal Council upcoming report, both lead to this same sort of measure.

It will require a sustained R&D effort and substantial investment in demonstration facilities. One example, the DOE Energy Industries of Ohio, Oakridge National Lab, EPRI, as well as the equipment suppliers, have been working on next generation superalloys for some years, but there is no demonstration path going forward at this point toward an ultrasupercritical coal technology of the advanced type in the U.S., as there is in Europe.

Technical barriers to reduce CO_2 include cost and energy, use of capture, and the assurance of safe storage, as we have talked about. We believe CCS costs and barriers can be overcome through a joint public and private research development demonstration effort.

We believe that they can be integrated into all types of new coal power plants, combined cycles, IGCCs, pulverized coal, fluidized bed combustion, oxyfuel, and that demonstrations are vital. In our opinion, no advanced coal technology is economically preferred for adopting CCS. When you add capture, it becomes a horse race, in our opinion.

If you use today's technology to capture, compress, transport, and store, you may see a cost increase of pulverized coal plants of 60 to 80 percent, 40 to 50 percent for an IGCC plant, in our estimation. With an aggressive research and development demonstration program, these costs can be brought down. Sites for long-term storage are regionally available throughout the U.S., yet there are major challenges to overcome, as you have heard. Specifically, we believe large-scale, greater than one million tons a year demonstrations, need to commence as soon as possible, and the legal and regulatory framework needs to be established for long-term ownership and liability.

We believe there are gaps in the policy toward, to quickly pursue this research, but primarily, policy toward establishing long-term liability for CO_2 storage when proper safeguards are in place. We believe there are pathways for this, and that industry and government need to act now to move this forward to improve efficiency, capture, and guiding principles for storage.

Thank you very much.

[The prepared statement of Mr. Dalton follows:]

PREPARED STATEMENT OF STUART M. DALTON

Thank you, Mr. Chairman, Ranking Member Inglis, and Members of the Committee. I am Stuart Dalton, Director of Generation for the Electric Power Research Institute (EPRI), a non-profit, collaborative R&D organization. EPRI has principal locations in Palo Alto, California, Charlotte, North Carolina, and Knoxville, Tennessee. EPRI appreciates the opportunity to provide testimony to the Committee on the topic of *"Prospects for Advanced Coal Technologies: Efficient Energy Production, Carbon Capture and Sequestration"*

I want to focus my comments today on three subjects: (I) the technological challenges our country faces in limiting carbon dioxide (CO_2) emissions from power plants that use coal as an energy source through both efficiency gains and CO_2 capture and sequestration (2) policy and research gaps where we believe the federal government can do more to facilitate the reduction of CO_2 emissions from coal, and (3) highlights from recent EPRI analytical work that emphasizes the importance of advanced coal technologies as part of an overall low-cost, low-carbon portfolio of options to reduce greenhouse gas emissions associated with climate change.

Background

Coal is the energy source for over half of the electricity generated in the United States, and numerous forecasts of future energy use show that coal will continue to have a dominant share in our electric power generation for the foreseeable future. Coal is a stably priced, affordable, domestic fuel that can be used in an environmentally responsible manner. Over the past three decades, development and application of advanced pollution control technologies and sensible regulatory programs have reduced emissions of criteria air pollutants from new coal-fired power plants by more than 90 percent. And by displacing otherwise needed imports of natural gas or fuel oil, coal helps address America's energy security and reduces our trade deficit with respect to energy.

By 2030, according to the Energy Information Administration, the consumption of electricity in the United States is expected to be approximately 40 percent higher than current levels. At the same time, to responsibly address the risks posed by potential climate change, we must substantially reduce the greenhouse gas emissions intensity of our economy in a way which allows for continued economic growth and maintains the benefits that energy provides. This is not a trivial matter—it implies a substantial change in the way we produce and consume electricity. Because coal contains a higher percentage of carbon than other fossil fuels such as natural gas, and because this carbon is emitted as CO_2, coal presents a greater challenge to achieving reduced greenhouse gas emissions.

Technologies to reduce CO_2 emissions from coal will necessarily be one part of an economy-wide solution that includes greater end-use efficiency, increased renewable energy, more efficient use of natural gas, expanded nuclear power, and similar transformations in the transportation, commercial, industrial, and residential sectors of our economy. In fact, our work at EPRI on the impacts of climate policy on technology development and deployment has consistently shown that non-emitting technologies for electricity generation will likely be less expensive than technologies for limiting emissions of direct fossil fuel end uses in other sectors.

EPRI stresses that no single advanced coal generating 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 economic impact lies in developing multiple technologies from which power producers (and their regulators) can choose the option best suited to local conditions and preferences. Assuring timely, cost-effective coal power technology with CO_2 capture entails simultaneous and substantial progress in research, development and demonstration (RD&D) efforts to improve capture processes and fundamental plant systems. EPRI sees the need for government and industry to pursue these and other pertinent RD&D efforts aggressively through significant public policy and funding support. Early commercial viability will likely come only through firm commitments to the necessary R&D and demonstrations and through collaborative arrangements that share risks and disseminate results.

Improvements and new development in several technology areas are required to achieve large scale reduction of CO_2 emissions from coal power plants. These needs can be described in three major aspects:

- Substantially increased thermodynamic efficiency of coal plants
- Cost-effective, efficient, commercially available technologies for capture of CO_2 from coal plants
- Cost-effective, commercially available technologies for storage of captured CO_2

Each of these areas presents substantial technology challenges requiring a sustained investment in RD&D.

Increasing Coal Plant Efficiency

Although the United States was an early leader in developing high-efficiency coal plant designs, we have built very few new coal power plants in the last two decades and are now playing catchup in the world race to achieve high-efficiency designs. In the 1950s and '60s, the United States was the world's pioneer in power plants using thermodynamically efficient "super-critical" and "ultra-super-critical" steam conditions. Exelon's coal-fired Eddystone Unit 1, in service since 1960, still boasts the world's highest steam temperatures and pressures. Because of reliability problems with some of these early units, U.S. designers retreated from the highest super-critical steam conditions until recently when international efforts involving EPRI and U.S., European and Japanese researchers concentrated on new, reliable materials for high-efficiency pulverized coal plants. Given the prospect of potential CO_2 regulations (and efforts by power producers to demonstrate voluntary CO_2 reductions), the impetus for higher efficiency in future coal-based generation units has gained economic traction worldwide. In fact, the majority of new pulverized coal (PC) plants announced over the last two years will employ high-efficiency super-critical steam cycles, and several will use the ultra-super-critical steam (USC) conditions with very high temperature, high efficiency designs heretofore used only overseas (aside from Eddystone).

EPRI is working with the Department of Energy, the Ohio Coal Development Office and major equipment suppliers on an important initiative to qualify a whole new class of nickel-based "super-alloys," which will enable maximum steam temperatures to rise from an ultra-super-critical steam temperature of 1100°F to an "advanced" ultra-super-critical steam temperature of 1400°F.

Combined with a modest increase in steam pressure, this provides an efficiency gain that reduces a new plant's carbon intensity (expressed in terms of tons of CO_2 emitted per megawatt-hour [Tons/MWh]) by about 20 percent relative to today's state-of-the-art plants. Even modest increases in steam conditions can raise efficiency by several percent in the near-term (a two percent increase in efficiency, for example, represents a roughly five percent reduction of CO_2 production and coal use). If capture of the remaining CO_2 is desired, improved efficiency will also reduce the required size of the capture equipment and the amount of coal mined and transported.

However, realization of this opportunity will not be automatic. In fact, it will require a renewed, sustained R&D commitment and substantial investment in demonstration facilities to bring new technologies to market. The European Union has embraced such a strategy and is midway through its program to demonstrate a pulverized coal plant with 1300°F steam conditions, which was realistically planned as a 20-year activity. Efficiency improvements will also be important for other coal power technologies. The world's first super-critical circulating fluidized-bed (CFB) plant is currently under construction in Poland. Many new units in China are being built with temperatures and efficiencies higher than recent U.S. units, as the cost of fuel and environmental pressures rise.

The greatest increase in efficiency for integrated gasification combined cycle (IGCC) units will come from increases in the size and efficiency of the gas turbines and improvements in their ability to handle hydrogen rich "syngas" that would be produced in IGCC plants designed for CO_2 capture.

A number of technologies are being developed that promise to decrease the amount of CO_2 per unit of power produced (e.g., pounds CO_2/kWh or Tons/MWh). With today's technology, a modern pulverized coal plant and a modern coal-based IGCC plant would produce roughly the same amount of CO_2/kWh. Neither achieves CO_2 capture without significant operational and hardware modifications and some loss of efficiency. Both are expected to achieve efficiency advances and cost reductions based on research and development occurring worldwide. EPRI believes that both industry and the government should support the development, demonstration, and deployment of multiple high-efficiency technologies for the future, rather than picking technology winners.

CO_2 Capture Technology

Carbon dioxide capture and storage (CCS) technologies can be feasibly integrated into virtually all types of new coal-fired power plants, including IGCC, PC, CFB and variants such as oxy-fuel combustion. For those constructing new plants, it is unclear which type of plant would be economically preferred if it were built to include carbon capture. All can have relative competitive advantages under various scenarios.

A utility's choice between these technologies will depend on available coals and their physical-chemical properties, desired plant size, the CO_2 capture process and its degree of integration with other plant processes, plant elevation, the value of plant co-products, and other factors. For example, IGCC with CO_2 capture generally shows an economic advantage with low-moisture bituminous coals. For coals with high moisture and low heating value, such as sub-bituminous and lignite coals, a recent EPRI study (report 1014510 available publicly) shows PC with CO_2 capture as competitive with IGCC with CO_2 capture. However, no single set of costs can represent all conditions. In addition to such variables as coal type and plant design, the cost of electricity will also vary due to plant location and the type of financing of the facility receives.

Post-combustion CO_2 Capture

Although carbon dioxide capture appears technically feasible for all coal power technologies, it poses substantial engineering challenges (requiring major investments in R&D and demonstrations) and comes at considerable cost. However, analyses by EPRI and the Coal Utilization Research Council suggest that once these substantial investments are made, the cost of CCS becomes manageable and, ultimately, coal-based electricity with CCS can be cost competitive with other low-carbon generation technologies.

Post-combustion CO_2 separation processes (placed after the boiler in the power plant) are currently used commercially in the food and beverage and chemical industries, but these applications are at a scale much smaller than that needed for power producing PC or CFB power plants. These processes themselves are also huge energy consumers, and without investment in their improvement, they would reduce plant electrical output by as much as 30 percent creating the need for more new plants.

EPRI's most recent cost estimates suggest that for PC plants, the addition of CO_2 capture using amine solvents (the most highly developed technical option currently available), along with drying and compression, pipeline transportation to a nearby storage site, and underground injection, would add 60–80 percent to the net present value of life cycle costs of electricity (expressed as levelized cost-of-electricity, or COE, and excluding storage site monitoring, liability insurance, etc.). With coal providing ~50 percent of U.S. electricity generation, this translates into a potentially significant increase in consumers' electric bills.

Oxy-firing

For PC plants, the introduction of oxy-fuel or oxy-coal combustion may allow further reductions in CO_2 capture costs by allowing the flue gas to be compressed directly, without any CO_2 separation process while also allowing the size of the supercritical steam generator to be reduced. Boiler suppliers and major European and Canadian power generators are actively working on pilot-scale testing and scale-up of this technology. AEP has recently announced plans to study use of this "oxy-coal" technology for retrofitting an existing plant, and SaskPower (Saskatchewan Power) has announced that, Babcock & Wilcox Canada (B&W) and Air Liquide will jointly develop the SaskPower Clean Coal Project.

Pre-combustion CO_2 Capture

CO_2 separation processes suitable for IGCC plants are used commercially in the oil and gas and chemical industries at a scale closer to that ultimately needed, but their application necessitates deployment of modified IGCC plant equipment, including additional chemical process steps and gas turbines that can burn nearly pure hydrogen.

The COE cost premium for including CO_2 capture in IGCC plants, along with drying, compression, transportation and storage, is about 40–50 percent. Although this is a lower cost increase in percentage terms than that for PC plants, IGCC plants initially cost more than PC plants. Thus, the bottom-line cost to consumers for power from IGCC plants with capture may be comparable to that for PC plants with capture, depending on the types of coal used, elevation of the plant and other site-specific factors.

It should be noted that IGCC plants (like PC plants) do not capture CO_2 without substantial plant modifications, energy losses, and investments in additional process equipment. As noted above, however, the magnitude of these impacts could likely be reduced substantially through aggressive investments in R&D. Historical experience with the development of environmental control technologies for today's power plants suggests that technological advances from "learning-by-doing" will likely lead to significant cost reductions in CO_2 capture technologies as the installed base of plants with CO_2 capture grows. An International Energy Agency study led by Carnegie Mellon University suggested that overall electricity costs from plants with CO_2 capture could come down by 15 percent relative to the currently predicted costs after about 200 systems were installed.

Furthermore, despite the substantial cost increases for adding CO_2 capture to coal-based IGCC and PC power plants, their resulting cost-of-electricity is still usually less than that for natural gas-based plants at current and forecast natural gas prices.

Engineering analyses by EPRI, DOE and the Coal Utilization Research Council suggest that costs could come down faster through CO_2 capture process innovations or, in the case of IGCC plants, fundamental plant improvements—provided sufficient RD&D investments are made. EPRI pathways for reduction in capital costs and improvements in efficiency are embodied in two companion RD&D Augmentation Plans developed under the collaborative CoalFleet for Tomorrow program. The IGCC plan (Report No. 1013219) is publicly available, and the PC plan will be available later this year. Efforts toward reducing the cost of IGCC plants with CO_2 capture will focus on adapting more advanced and larger gas turbines for use with hydrogen-rich fuels, lower-cost oxygen supplies, improved gas clean-up, advanced steam cycle conditions and other activities.

CO_2 Transportation and Geologic Storage

Geologic sequestration of CO_2 has been proven effective by nature, as evidenced by the numerous natural underground CO_2 reservoirs in Colorado, Utah and other western states. CO_2 is also found in natural gas reservoirs, where it has resided for millions of years. Thus, evidence suggests that depleting or depleted oil and gas reservoirs, and similar "capped" sandstone formations containing saltwater that cannot be made potable, are capable of storing CO_2 for millennia or longer. Geologic sequestration as a strategy for reducing CO_2 emissions is being demonstrated in numerous projects around the world.

Three relatively large projects—the Sleipner Saline Aquifer CO_2 Storage (SACS) project in the North Sea off of Norway; the Weyburn-Midale Project in Saskatchewan, Canada and the In Salah Project in Algeria—together sequester about three to four million metric tons of CO_2 per year, which approaches the output of just one typical 500 megawatt coal-fired power plant. With 17 collective years of operating experience, these projects suggest that CO_2 storage in deep geologic formations can be carried out safely and reliably. Furthermore, CO_2 injection technology and subsurface behavior modeling have been proven in the oil industry, where CO_2 has been injected for 35 years for enhanced oil recovery (EOR) in the Permian Basin fields of west Texas and Oklahoma and in other U.S. fields. Regulatory oversight and community acceptance of injection operations are well established in those contexts.

Within the United States, DOE manages an active R&D program, the Regional Carbon Sequestration Partnerships, that is mapping geologic formations suitable for CO_2 storage and conducting pilot-scale CO_2 injection validation tests across the country. These tests, as well as most commercial applications for long-term storage, will compress CO_2 to a liquid-like "super-critical" state to maximize the amount that can be stored. Virtually all CO_2 storage will be at least a half-mile underground, where the CO_2 will be injected into a porous sandstone-like material saturated with salty water. CO_2 will be stored in locations with geologic seals to minimize the likelihood of any leakage to the atmosphere (which would defeat the purpose of sequestering the CO_2 in the first place).

DOE's Regional Carbon Sequestration Partnerships represent a broad collaboration of public agencies, private companies and non-profits; they would be an excellent vehicle for conducting larger "near-deployment scale" CO_2 injection tests to prove specific U.S. geologic formations, which EPRI believes to be one of the keys to commercializing CCS for coal-based power plants. Evaluations by these Regional Partnerships and others suggest that enough geologic storage capacity exists in the United States to hold several centuries' worth of CO_2 emissions from coal-based power plants and other stationary sources. However, the distribution of suitable storage formations across the country is not uniform: some areas have ample storage capacity whereas others appear to have little or none.

Thus, CO_2 captured at some power plants would require pipeline transportation for several hundred miles to reach suitable injection locations, which may be in other states. While this adds cost, it does not represent a technical hurdle because CO_2 pipeline technology has been proven in oil field FOR applications. As CCS is applied commercially, EPRI expects that early projects would take place at coal-based power plants near to sequestration sites or to existing CO_2 pipelines. As the number of projects increases, regional CO_2 pipeline networks connecting multiple sources and storage sites would be needed.

There is still much work to be done before CCS can implemented on a scale large enough to significantly reduce CO_2 emissions into the atmosphere. In addition to large-scale demonstrations at U.S. geologic formations, many legal and institutional uncertainties need to be resolved. Uncertainty about long-term monitoring requirements, liability and insurance is an example. State-by-state variation in regulatory approaches is another. Some geologic formations suitable for CO_2 storage underlie multiple states. For private companies considering CCS, these various uncertainties translate into increased risk.

The Promise of CCS

Recent EPRI work has illustrated the urgent necessity to develop CCS technologies as part of the solution to satisfying our energy needs in an environmentally responsible manner. Our recently released "Electricity Technology in a Carbon-Constrained Future" study suggests that with aggressive R&D, demonstration and deployment of advanced electricity technologies, it is technically feasible to slow down and stop the increase in U.S. electric sector CO_2 emissions, and to then eventually reduce them over the next 25 years while simultaneously meeting the increased demand for electricity. Of the technologies that can eventually lead to reductions in CO_2 emissions, the study indicates that the largest single contribution would come from applying CCS technologies to new coal-based power plants coming on-line after 2020.

Many other U.S. and international climate models and reports have stressed that CCS is a vital part of the needed technology mix in any carbon-constrained future. We believe action is needed now to assure we can meet these technological and cost challenges.

R&D Gaps

A gap in the policy and RD&D area that EPRI believes needs to be addressed by the U.S. industry and government is the funding of multiple capture, transport, and storage demonstrations at large scale (>1 million metric tons per year of CO_2). These demonstrations should encompass a variety of coal technologies and capture processes, and should be conducted in multiple regions, using varying geologic formations. Monitoring will need to be conducted to assure long-term storage effectiveness.

Engineering analyses by EPRI, DOE and the Coal Utilization Research Council suggest that costs could come down faster through CO_2 capture process innovations or, in the case of IGCC plants, fundamental plant improvements—provided sufficient RD&D investments are made. Combined with EPRI's past experience in transforming science into deployed technologies, these analyses clearly indicate that a sustained and substantial RD&D investment will be necessary to assure the availability of CCS and levels of coal plant performance compatible with potential CO_2 policies.

EPRI pathways for reduction in capital cost and improvement in efficiency for IGCC plants are embodied in an RD&D Augmentation Plan developed under the CoalFleet for Tomorrow program. This figure shows how efficiency can be increased over the next two decades as costs are decreased in constant dollar terms. The detailed plans for this have been developed in our collaborative efforts with firms form five continents and over 60 participants. A similar figure appears for combustion processes and shows equally impressive efficiency and cost gains. Neither of these can be realized without a strong commitment to research development and demonstration.

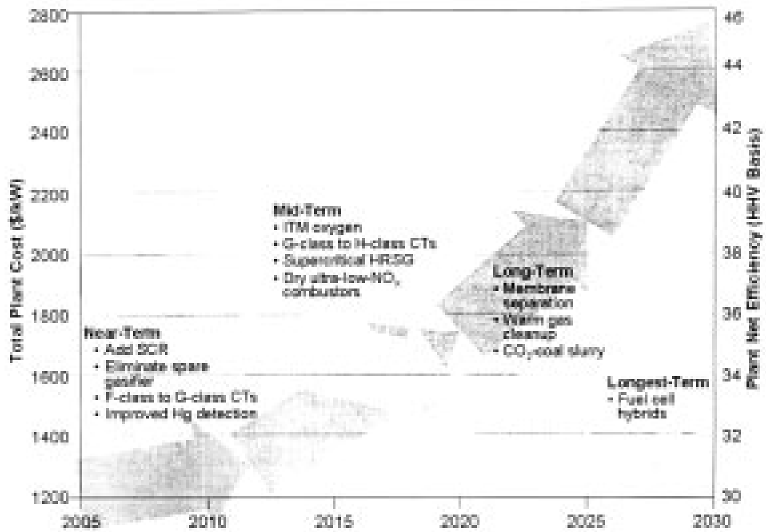


Figure 1: Forecast Reduction in Capital Cost and Improvement in Efficiency Through Implementation of the EPRI CoalFleet IGCC RD&D Augmentation Plan
(Slurry-fed gasifier, Pittsburgh #8 coal, 90% availability, 90% CO_2 capture, 2Q 2005 U.S. dollars)

Efforts toward reducing the cost of IGCC plants with CO_2 capture will focus on adapting more advanced and larger gas turbines for use with hydrogen-rich fuels, lower-cost oxygen supplies, improved gas clean-up, advanced steam cycle conditions, and more.

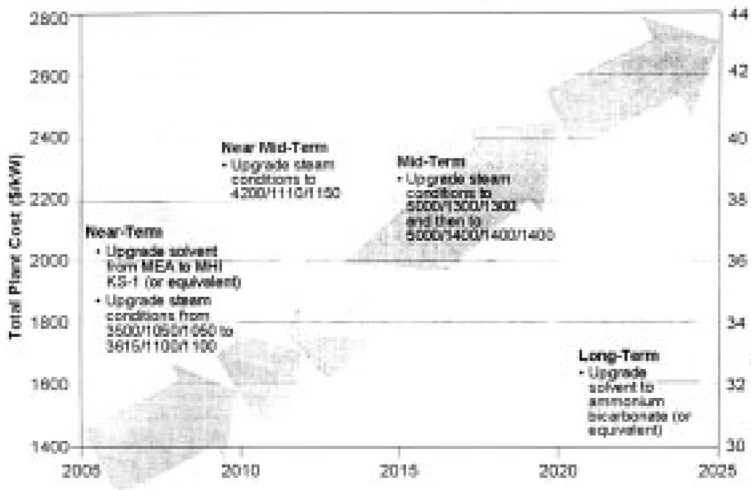
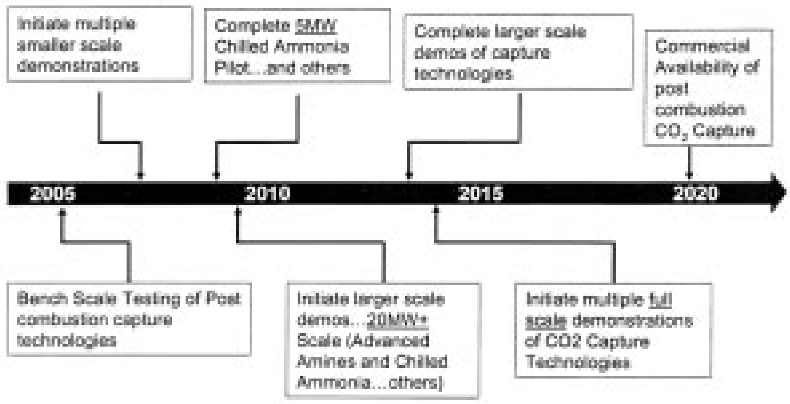


Figure 2: Forecast Reduction in Capital Cost and Improvement in Efficiency through Implementation of the CoalFleet USC PC RD&D Augmentation Plan

(Pittsburgh #8 coal, 90% availability, 90% CO_2 capture, as-reported data from various studies [not standardized])

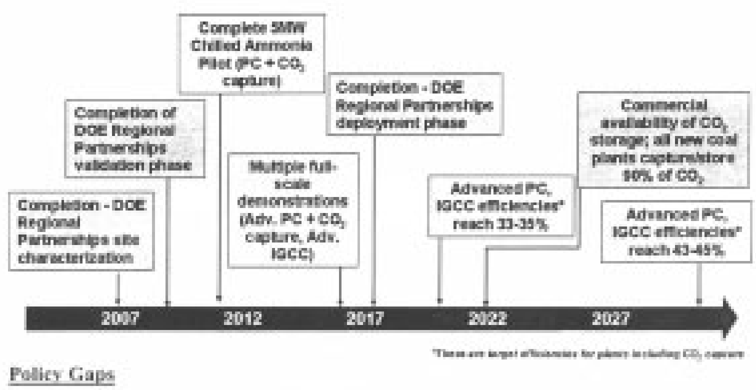
For PC plants, the progression to advanced ultra-super-critical steam conditions will steadily increase plant efficiency and reduce CO_2 production. Improved solvents are expected to greatly reduce post-combustion CO_2 capture process. EPRI is working to accelerate the introduction of novel, alternative CO_2 separation solvents with much lower energy requirements for regeneration. Such solvents—for example, chilled ammonium carbonate—could reduce the loss in power output imposed by the CO_2 capture process from about 30 percent to about 10 percent. At present, a small pilot plant (five MW-thermal) for chilled ammonia is being designed for installation at a power plant in Wisconsin later this year; success there would warrant a scale-up to a larger pilot or pre-commercial plant. An EPRI timeline (compatible with DOE's timeframe) for the possible commercial introduction of post-combustion CO_2 capture follows.



The introduction of oxy-fuel combustion may allow further reductions in CO_2 capture costs by allowing the flue gas to be compressed directly, without any CO_2 separation process and reducing the size of the super-critical steam generator. Boiler suppliers and major European and Canadian power generators are actively working on pilot-scale testing and scale-up of this technology.

Assuring timely, cost-effective coal power technology with CO_2 capture entails simultaneous and substantial progress in RD&D efforts on improving capture processes and fundamental plant systems. EPRI sees the need for government and industry to pursue these and other pertinent RD&D efforts aggressively through significant public policy and funding support. Early commercial viability will likely come only through firm commitments to the necessary R&D and demonstrations and through collaborative arrangements that share initial risks and disseminate results.

The urgent need to establish an enhanced RD&D program for developing advanced coal and carbon capture and storage technologies is further increased by the likelihood that, as is typical for research, unexpected technical challenges will surface and require additional time, effort and funding to resolve.



Policy Gaps

Without incentives or regulatory requirements, or a market for CO_2, CCS will not be chosen based on economics. In addition to incentives to encourage use of CCS, the State and Federal governments will need to deal with the issues of land use, ownership, and liability for CO_2. This is perhaps the biggest unknown. No company can take on unlimited liability—options will be needed to allow firms to make long-term commitments to the technology. Such options may include special insurance provisions, State or federal liability provisions, and must include clarity in regulatory requirements for long-term storage of CO_2. Models and current analogies lead us, and many in the industry, to believe that the risk should be manageable, but the unknowns of long-term liability makes this risk difficult to manage.

Conclusions

Our country does face significant technology challenges in limiting CO_2 emissions from coal and it will require multiple technological approaches for capture and multiple storage demonstrations to prove the cost, efficiency, and effectiveness of CO_2 capture and storage. These must be pursued in the near future to provide options for CO_2 capture and storage on timeframes compatible with potential policies.

Our research indicates that with proper support and an RD&D program sustained over the coming decades, the technology for CCS can play a significant role in reducing CO_2 emissions from the power industry to meet future national requirements.

Summary of Testimony

Coal is a stably priced, affordable, domestic fuel that can be used in an environmentally responsible manner. It is the workhorse of the U.S. electricity grid, accounting for more than half of all the power generated. Forecasts of future U.S. energy needs envision the continued predominance of coal in the electric power sector. Thus, technologies to reduce CO_2 emissions from coal-based power plants must be part of the set of solutions to climate change concerns. For the electric sector, that portfolio will also include improved efficiency in transmission and end use, increased renewable energy, more efficient use of natural gas, and expanded nuclear power. Analogous low-carbon transformations must occur in the economy's transportation, commercial, industrial, and residential sectors. Even within the sub-sector of coal-based electricity, EPRI stresses that a portfolio of advanced coal technologies is needed. No single technology has clear-cut economic advantages across the range of U.S. applications. The best strategy for reducing CO_2 emissions lies in developing multiple technologies from which power producers (and their regulators) can choose the option best suited to local conditions and preferences.

An often-cited step is improving the efficiency of new coal power plants. This can achieve CO_2 reductions of up to 20 percent per megawatt hour of electricity before the addition of any dedicated CO_2 controls. The MIT "Future of Coal" report and a forthcoming report by the National Coal Council endorse this fundamental measure. Realization of this opportunity will require a sustained R&D commitment and substantial investment in demonstration facilities. EPRI, DOE, Ohio Coal Development Office, and equipment suppliers have a program in place.

EPRI and others believe that CO_2 capture and sequestration (CCS) technologies for coal-based power plants will be an indispensable technology for achieving the deep cuts in man-made CO_2 emissions needed to stop, and ultimately reverse, atmospheric build-up. CCS technologies can be feasibly integrated into all types of new coal power plants, including integrated gasification combined cycle (IGCC), pulverized coal (PC), circulating fluidized-bed (CFB), and variants such as oxy-fuel combustion. No advanced coal technology is economically preferred for adopting CCS, and the field of CO_2 capture technology options is evolving quickly at small-scale, but large demonstrations are vital. Sites for long-term geologic storage of CO_2 are regionally available throughout much of the United States. Yet, there are major challenges to be overcome—both technically and in terms of public policy—before geologic storage of CO_2 can be applied at the broad scale needed. Specifically, multiple large-scale (>1 million tons) demonstrations need to commence as soon as possible. Legal and regulatory frameworks need to be established, particularly with respect to long-term ownership and liability.

RD&D pathways to success have been established collaboratively by EPRI, DOE, and industry groups. The RD&D funding needs are a significant step up from current levels, but within historical percentages for government agencies and private industry. Given the long technology development and deployment lead times inherent in capital intensive industries like energy, investment and policy decisions must be made now or we risk foreclosing windows of opportunity for technology options that we expect will prove tremendously valuable in a carbon-constrained future.

BIOGRAPHY FOR STUART M. DALTON

Stuart M. Dalton is a Director in the Generation Sector. His current research activities cover a wide variety of generation options with special focus on emerging generation, renewables, and coal-based generation, emission controls, and CO_2 capture and storage.

Mr. Dalton joined EPRI in 1976 as a Project Manager focused on SO_2 control and later led this area for 20 years, additionally working on integrated emission controls for NO_X, mercury, and particulates. He helped lead industry efforts to reduce costs, improve reliability, and apply these technologies.

Before joining EPRI, Mr. Dalton worked at Pacific Gas & Electric evaluating new generation options (coal gasification and conventional coal), refuse firing, and NO_X control retrofits. Prior to that he worked at Babcock and Wilcox focusing on power plants and emission controls.

Mr. Dalton holds a BS in chemical engineering from University of California, Berkeley.

Mr. Dalton helped create the EPRI CoalFleet for Tomorrow® program and, more recently, helped develop CO_2 capture and storage work as well as EPRI's ocean energy program.

The U.S. State Department has designated Mr. Dalton as one of two official U.S. Asia Pacific Partnership (APP) industry delegates to the Cleaner Fossil Task Force. In addition, he is leading EPRI's contribution to the National Coal Council report on CO_2 Capture and Storage and the Coal Utilization Research Council's CURC/EPRI Roadmap.

Chairman LAMPSON. Thank you. Mr. Hill.

STATEMENT OF MR. GARDINER HILL, DIRECTOR, CCS TECHNOLOGY, ALTERNATIVE ENERGY, BP

Mr. HILL. Mr. Chairman, ladies and gentlemen, I feel honored to be invited here today to talk about CO_2 capture and storage. I am indeed heartened that the Science and Technology Committee is holding a hearing on this technology, given the potential it has to play a critical role in helping address the climate change problem.

A number of the elements of CO_2 geological storage have been practiced for over 30 years in activities such as: Enhanced Oil Recovery (EOR), where we typically use CO_2 to inject into oil reservoirs and flush more oil recovery; in the gas storage operations, where gas is stored underground, so we have availability and operability of the gas system; and in acid gas injection operations. Something on the order of 20 million tons of CO_2 per year is currently injected into geological formations for EOR, so we already have a lot of experience.

So, what have we learned about CO_2 geological storage over this time and through subsequent technology R&D? Well, we know the best rocks for CO_2 storage are depleted oil and gas fields and deep saline formations. Now, these are layers of porous rock, typically very deep, below a kilometer, and they are located under an impermeable rock known as a caprock, which acts as a seal to the main reservoir. The Intergovernmental Panel on Climate Change, the IPCC, has estimated the technical potential for CO_2 storage is likely to exceed 2,000 gigatons or 2,000 billion tons of CO_2, with the largest capacity likely to exist in saline formations.

So, given that today's CO_2 emissions are approximately 24 gigatons of CO_2 from fossil fuels, geological storage has the capacity to store about 70 to 100 years of all emissions from fossil fuels. On the other hand, others have estimated that CCS has the potential to contribute a quarter of the emission reductions required to address climate change, and in that scenario, you can envision 400 years of CCS storage.

In addition, a critical thing to remember about CCS is its flexibility and adaptability. And when CO_2 is stored through the use of an EOR operation, as I discussed earlier, there is a genuine win/win for the environment and energy security.

But what are the outstanding risks in the matter of CO_2 storage? Well, it turns out this is not dissimilar to today's oil and gas industry. Local health, safety, and environmental risks associated with geological storage can be comparable to the risks of current activities, such as natural gas storage, EOR, and deep underground disposal of acid gas, provided best practice is applied in four keys area.

The first one is site selection. The second one is the design of the storage and the operation of the storage facility. The third one is putting in place a robust monitoring program to validate your understanding of the storage system, and the fourth one is site abandonment, so you have integrity and seal of that storage site.

Now, over and above these four areas, there are two critical frameworks I think are necessary to have managed these risks, and ensure we have consistency in the way CO_2 is stored. And one is the important regulatory framework for CCS, and the second one is a CO_2 storage site certification framework, so we have a consistent standard applied.

So, what are the things we should consider when selecting a storage site? Well, I think there are three primary things to bear in mind. The first one is capacity. Does the site have enough space to store a large amount of CO_2? The second one is injectivity. Can you actually get the CO_2 in the rock and actually fill it up? And the third one, importantly, is integrity. Will the site store the CO_2 for the timeframe required?

So, that means we need to understand the competence of the structure, the stratigraphic trap, you need to understanding the faulting within geological structure, because that could contribute to a leak or, indeed, compartmentalization of the rocks, you don't get access to all the pore space. You need to understand the geochemistry, the number of wells you need to store the CO_2 and the design of the wells, so you have integrity for the life of the installation. But as I said before, a key element is the performance prediction, and we have to have a monitoring and verification program to validate the understanding of the storage site.

Now storage, secure storage, actually increases over time, and that occurs through the interaction of four different trapping mechanisms. Some can be engineered to enhance the trapping, and hence, is important to understand the role that each of these mechanisms play when selecting a storage site. So, the first one, as I have mentioned, is structural trapping, where you have an impermeable rock above the formation, which actually physically traps the CO_2 moving up.

The second mechanism is called residual phase trapping. That is simply CO_2 going into like a sponge. You have a sponge you have in your bath that you fill with water, sinking the CO_2 in a rock, the CO_2 goes into the pores in that sponge in that rock and gets trapped between the pore, and becomes totally immobile, just like you can't get the water out of the sponge unless you squeeze it.

The third one is solubility, and that is where your CO_2 dissolves in water, in your fizzy water, and what happens is the density of that water increases, so that water, then, sinks to the bottom of the reservoir, and can't possibly come out, because of the density difference.

And the fourth one is mineral trapping, and that is where the CO_2 reacts with some of the minerals in the formation, and you get physical hard scales forming, so it is physically trapped in a solid form, and hence the security of storage increases with time.

So, what steps remain to be taken so we can design long-term carbon sequestration projects? Well, clearly, technology development must continue, and has an important role to play, but my sense is the time is now right to embark upon large-scale demonstration projects, and I would say that is a million tons or more per year projects. And it is important we demonstrate and we look and we try to demonstrate in a number of different types of reservoirs in different locations. And we need to truly learn by doing at scale.

This needs to be done in a managed way by something like a deployment strategy, which is a framework or plan that is consistent with a clear objective that will be achieved by a certain point in time. We need to set a goal and put in place a plan to achieve the goal, being clear and transparent on the conditions of satisfaction required one way, so we can secure the public's confidence in this technology.

It is clear we need to put in place regulations and policy measures that will allow geological studies to happen. Industry needs a regulatory framework, so that the operating conditions are clear, and industry needs a policy framework so we can define the necessary business and commercial conditions for CO_2 storage. We need to also identify and remove roadblocks to technology, and I will give you two examples.

One roadblock, potentially, is what happens to any liability associated with CO_2 storage after a storage site is full and safely abandoned. Another example could be who owns the pore space? The number of laws in the U.S. are unclear in some cases about ownership of the very pore space in the rocks that will be used for storing CO_2. So, removing these barriers, and a deployment strategy that is open and transparent, with the appropriate regulations, I think are really important to convincing public, regulators, and governments alike that CCS is a safe and important technology to help solve climate change.

Ladies and gentlemen, it is time to get into action. It is time to get on with the job. This technology is available now, and with some help, we can make it happen at scale. And this is actually being demonstrated today by BP, who have announced two hydrogen power projects which will utilize CO_2 capture and geological storage to use carbon power from fossil fuels.

Thank you very much.

[The prepared statement of Mr. Hill follows:]

PREPARED STATEMENT OF GARDINER HILL

Chairman Lampson, Ranking Member Inglis, thank you for inviting me to testify here today on carbon capture and sequestration. I am Gardiner Hill, Director of CCS Technology at BP, and a petroleum and civil engineer by training.

For those of you who don't know, BP has made a commitment to investing $8 billion over the next 10 years in alternative energy—including wind, solar, and fossil-fuel powered power plants with carbon capture and sequestration (CCS). We have announced two projects using CCS—one in Scotland, the other at our Carson refinery in California.

BP, and the oil and gas industry generally, has more than thirty years of experience injecting carbon dioxide in oil and gas reservoirs. We do so every day for enhanced oil recovery-injecting CO_2 into depleted oil reservoirs, recovering the remaining oil, and inevitably leaving CO_2 behind. In other words, CO_2 storage is a technology that is available today and we know that it has the potential to play a significant role in helping to reduce CO_2 emissions into the atmosphere, helping to combat climate change.

My role today is to explain how CO_2 stays underground. It is important to understand that many natural geological stores of CO_2 have been discovered underground—often by people looking for oil and gas. In many cases, the CO_2 has been trapped underground for millions of years in geological traps, plus CO_2 is also found indigenous in many oil and gas fields, where is has been stored underground naturally for millions of years. It is true that under certain circumstances, CO_2 does leak naturally from underground. Indeed the world's natural carbonated mineral waters, long prized and bottled for drinking, come from natural CO_2 sources. The reasons why some rock formations trap the CO_2 permanently and some do not are well understood and this understanding will be used to select and manage storage sites to minimize the change of leakage.

The best rocks for CO_2 storage are depleted oil and gas fields and deep saline formations. These are layers of porous rock, such as sandstone, more than half a mile underground, located underneath a layer of impermeable rock, or cap-rock, which acts as a seal. In the case of oil and gas fields, it was this cap-rock that trapped the oil and gas underground for millions of years.

Depleted oil and gas fields are the best places to start storing CO_2 because their geology is well known, and they are proven traps.

Deep saline formations are rocks with pore spaces that are filled with very salty water—much saltier than seawater. They exist in most regions of the world and appear to have a very large capacity for CO_2 storage. However, the geology of saline formations is currently less well understood than that of oil and gas fields and so more work needs to be done to understand which formations will be best suited to CO_2 storage, but the potential appears to be huge!

So why does CO_2 stay underground? As CO_2 is pumped deep underground it is compressed by the higher pressures and becomes essentially a liquid, which then becomes trapped in the pore spaces between the grains of rock. The longer the CO_2 remains underground, the more securely it is stored. There are four different ways that CO_2 gets trapped underground.

The first mechanism is called structural storage. This can be best demonstrated by BP's joint venture with Sonatrach called In Salah, which is a natural gas development in Central Algeria. At In Salah, the natural gas produced from the deep rock formations is a mixture of methane (CH4) and CO_2. Once it reaches the surface, the natural gas is separated into methane and CO_2. The Methane gas is pumped North to Europe, while the CO_2 is pumped deep underground—back into the rock formations from which the natural gas was originally extracted. One million tons per year of captured CO_2 is injected and stored in this way. When it is pumped deep underground, it is initially more buoyant than water and will rise up through the porous rocks until it reaches the top of the formation where it is trapped by an impermeable layer of cap-rock, such as shale at the In Salah field. The cap-rock that kept the natural gas in the rock formation for millions of years keeps the liquid CO_2 stored in the underground reservoir. The wells that were drilled to place the CO_2 in storage can be sealed with plugs made of steel and cement.

The second mechanism is where CO_2 gets trapped in the rock pore space through what is known as residual trapping. In this instance, the reservoir rock acts like a tight, rigid sponge. When liquid CO_2 is pumped into a rock formation, much of it becomes stuck within the pore spaces of the rock and does not move.

The third mechanism is called dissolution storage. In this instance, CO_2 dissolves in salty water, just like sugar dissolves in tea. The water with CO_2 dissolved in it is then heavier than the water around it and so it sinks to the bottom of the rock, trapping the CO_2 indefinitely.

And finally, the fourth mechanism is when CO_2 dissolves in salt water, becoming weakly acidic and reacting with the minerals in the surrounding rocks, forming new minerals as a coating on the rock—much like shellfish use calcium and carbon from seawater to form their shells. This process effectively binds the CO_2 to the rocks, trapping it there.

We have the technology and the knowledge to get started on storing carbon underground. BP, in partnership with Edison Mission, has announced a CCS project at our Carson refinery in Southern California. We will be taking petcoke, a refinery byproduct, and gasifying it. The resulting hydrogen will be used to power a 500 megawatt power plant, and the CO_2 will be stored underground, probably via an Enhanced Oil Recovery process (EOR), which is the mechanism I outlined at the start of the testimony in which industry has over 30 years experience. We know that CCS is part of the solution to the climate change problem, i.e., ref. IPCC special report and Princeton Wedges analysis, etc.—estimates are that CCS technology has the capability to contribute around a quarter of the emission reductions needed to get to environmental stabilization. We have the technological know-how to do this, we need the policy and regulatory framework to enable its deployment.

Thank you and I welcome any questions you may have.

DISCUSSION

CARBON SEQUESTRATION RISKS

Chairman LAMPSON. Thank you very much. We will now begin with our first round of questions, and I will recognize myself for five minutes. And I would start with a whole bunch of questions at one time, if you will forgive me for doing this, and do them as best you can, and I would like to ask Mr. Bauer, Dr. Finley, and Mr. Hill to respond to these.

I understand that CO_2 storage is a technology that is available today, as we have heard, and could play a significant role in reducing CO_2 emissions into the atmosphere. Do we know what the probability is of a carbon release from a geological site? What research and data are available to understand the environmental and human health and safety risks? Are there well established risk assessment methodologies for geological storage of CO_2? Let me start with those, and then I am going to ask two more.

Dr. FINLEY. Well, I think with regard to the probabilities of release, I think yes, there is a probability of release. It is very difficult to quantify at this point in time. The natural gas storage industry has had many very safe and operational natural gas storage facilities. For example, we have one in Champaign County, Illinois that stores 150 billion cubic feet of flammable natural gas over an area of 25 square miles, and that facility has been in place since the early 1970s, and to the best of our knowledge, never has had a leak to surface or a problem.

So, we have some analogies out there. We need to take advantage of those analogies, and I think with the advent of the large-scale testing that is being proposed here, and that we are moving toward on the regional partnerships, it is really going to give us an opportunity to put in place a series of sensors, observation wells, and the like, that I think will really begin to try and take this largely qualitative understanding, and move it over into the quantitative arena, as you suggest.

Mr. BAUER. I would agree with that, and I think Gardiner Hill did a great job of describing basically what a reservoir would be, which is really not a void. It is a rock, it is a permeable rock, and many people get concerned about a rapid release, but from a permeable rock, it doesn't just spring out in tremendous force. To be a volcanic void, and there has been a couple incidents in history recorded, where a volcanic void erupted, with CO_2 being released in a low-lying area, and there was a concern, but that is not the kind of capture area, plus the capstone rock being very important.

We do have data, the regional partnerships have done some great things in the first two phases, at both analysis and collecting data, but the third phase, which we are entering this year, is to do projects towards the million ton per year level, and to catch, gather greater data for that. On the area of risk assessment, there are abilities to do risk assessment. The application to this particular arena is not really done, except from the standpoint, I think, and Gardiner, maybe you could speak to the EOR and the risk assessments about there, that might be of enlightenment to you.

Mr. HILL. Thank you very much. I think this is all about risk management, actually. And the way we approach this is by taking fundamental review of the risks, and making sure these are managed adequately. But let me start by saying there is a lot of experience. I mean, there is many examples of gas storage, which is clearly more dangerous than CO_2, because of the increased buoyancy and the flammability of gas, many years of EOR, and indeed, we actually have a number of CO_2 natural gas fields that exist, or CO_2 natural reservoirs that exist in the U.S., that primarily are used today for supplying CO_2 for EOR.

So, we can actually go and look and study these CO_2 natural reservoirs that have occurred for millions of years, and why CO_2 has stayed there for millions of years. And indeed, we have done studies to undertake the performance of the natural gas storage system, and there is examples in Europe where there is a very large natural gas storage system, actually under the City of Berlin itself. So, there is real examples of where gases, like CO_2 and perhaps even more volatile, are actually stored in fairly public places very safely and with a great track record.

REGULATORY REQUIREMENTS

Chairman LAMPSON. Okay. Let me interrupt you, because I have got 50 seconds left, and I want to try to be a little bit better on my timing this time.

Let me ask the last two questions of you for this particular section for me, and then, I will catch something else a little bit later, but who should manage and monitor the sequestration sites, and secondly, does the EPA have good regulatory structure in place to adequately address the review and oversight necessary for large-scale carbon sequestration?

Mr. BAUER. On the matter of who should regulate, I won't take that one on directly, because of my position, but we are working with the EPA to put in information and to prepare regulatory requirements. They do not presently have one of sequestration, they do have it for injection wells. There was a letter of guidance released March 7 of this year from EPA, giving direction of large-scale injection, but the long-term storage is not framed properly yet.

Chairman LAMPSON. Dr. Finley or Mr. Hill, would you comment?

Dr. FINLEY. Yeah, I think, as Carl mentioned, yes, the U.S. EPA has issued these guidelines looking at, classified as experimental under the underground injection control regulations, as a place to start. I think the Interstate Oil and Gas Compact Commission has been working now for several years, looking at the State regulatory framework, because after all, under UIC, states that have primacy, for example, do regulate as Class 2 the wells that deal with oil and gas and EOR, which Gardiner has referred to.

So, I think basically, I think the States need to have an important role in it, but the exact framework of that role has yet to be defined.

Mr. HILL. Yes. I would validate that. I think it is an important thing to tackle regulations, I think, when you take groups together, to make sure we have the right people who can write the right regulations.

We are involved in helping, we would like to be involved in helping develop these, given the experience we have through EOR and through CO_2 storage, like in Sowerfield, where we are injecting a million tons per year of CO_2 which is stored annually.

Chairman LAMPSON. Thank you very much. Ranking Member Inglis, recognized for five minutes.

CARBON SEQUESTRATION SITES

Mr. INGLIS. Thank you, Mr. Chairman. Now, I am a commercial real estate lawyer, not a scientist, which will become obvious in the midst of these questions that I am about to ask.

But one of the things you say in real estate, you know, is three things determine the value of real estate, location, location, location. And so, the question that I have about the geological formations is how common are they, and are they located in places that are usable? I mentioned in my opening statement the Duke power plant in South Carolina that may be a coal-fired plant. How readily available are these locations for the kind of storage that we are talking? Anybody want to, whoever wants to take a shot at that?

Dr. FINLEY. Well, I think, I mean it depends on the type of rocks. I was in Madison, Wisconsin two weeks ago, and listened to the Wisconsin State geologist proclaim very clearly that the State of Wisconsin has very limited opportunity to store carbon dioxide in the rock framework. I am afraid that is also the case for much of the Atlantic coastal plain, which you represent with regard to South Carolina. I got my Ph.D. at Columbia, and so, I have some knowledge of the geology of the State of South Carolina.

But basically, it is the rock framework, but that is not to say that we are restricted locally within that rock framework, because after all, we have more than a million miles of natural gas pipelines in this country that deliver natural gas from our shore of the Gulf of Mexico to the State of Maine, for that matter. So, basically, I think what can be adapted is find the places where the geology is suitable, where it is safe and where it can be effective, and if you have places where the coal resources or the water resources are available, such that power generation is appropriate there, then we can build an infrastructure to move the CO_2 to where it can be safely stored.

CARBON DIOXIDE TRANSPORTATION

Mr. INGLIS. So, then, we would likely be talking about moving CO_2, pipeline system. I guess a truck would not be effective, right, because there is a lot of it, so you got to move it, which the next question is, is the other thing about commercial real estate, as we say, you know, they are not making any more of it, which makes it valuable, real estate that is. And so, the question is how quickly before these formations are used up? What kind of capacity do we have?

Mr. BAUER. Well, I think as Dr. Finley gave in his testimony, there are multiple hundreds of years of geologic storage capacity available. It goes back to location. They may not be always available where you are. I think as Gardiner also mentioned, making sure you have a sufficient reservoir when you start to meet your stand for longevity there, is also something to determine.

So, the bottom line is there is plenty of storage available. The geographic location may not always be in the right place. You may have to pipeline to it. But for the Nation, about 97 percent of the areas that use coal power today have geologic storage within a reasonable distance, 50 to 100 miles, at maximum, to be pipelined, many times, even right below a facility presently.

Mr. HILL. Can I just add to that? I think this is actually a volume issue, and that if CCS is to make a contribution to climate change, then we are actually talking about huge volumes, and in my statement, I said it could contribute up to a quarter of the reductions required to help stabilize emissions. Now, even a quarter contribution is something like equivalent to 125 million barrels equivalent of oil, so that is an industry big as the oil industry. Currently the oil industry is about 18 million barrels per day, so if CCS is doing only a quarter of the reductions required emissions, you are talking a business, an infrastructure, at least equivalent at least equivalent to these oil industry, so it will be a big infrastructure requirement. At times, there are a number of oil and gas fields that are very suitable to store CO_2, but there is actually a lot larger capacity in these deep saline formations, which turn out to be quite extensive across the U.S., and in fact, most of the world.

Mr. RENCHECK. I would like to add on that, regional partnerships, the importance of continuing the drilling into the saline aquifers. While we understand a lot about the oil formations and gas formations, these rock structures in some cases are 9,000 feet below the surface. At our Mountaineer Plant, we participated in the drilling of that, understanding the geology, and we think we need to do more of that, so we understand the geology at those deep levels.

CARBON SEQUESTRATION ATLAS

Mr. INGLIS. I have more questions, but my time is almost up. Mr. Bauer, just to make sure, how much, you said within 50 miles, we have what percent of the capacity?

Mr. BAUER. When we did the Atlas, which Dr. Finley held up, and I have a couple digital versions I would be glad to leave with the Committee, it identified that there were plenty of reservoirs, and the regional partnerships cover about 97 percent of the land mass of the United States, which also happens to coincide to about 97 percent of the power plant areas, and well within that realm, there is pretty much sequestration availability for most of those plants within a reasonable transmission framework, and going with what Gardiner said, we are talking mainly with saline aquifers, as well as oil and gas fields that would be expended or used for EOR before expending.

Chairman LAMPSON. Mr. Costello, you are recognized.

CCS TECHNOLOGY READINESS

Mr. COSTELLO. Mr. Chairman, thank you, and I thank all of the witnesses for their thoughtful testimony.

I would like to try and clarify a few points, and then, ask a few questions as well. One is that I think it is important to clarify that while CCS technology will enable our power plants to operate more efficiently, and enable them to not only operate more efficiently, but reduce emissions, that there are legitimate reasons why utility companies and the coal industry are not using the technology today, and until the technology is ready to be deployed on a commercial scale basis, I believe that a mandate from Congress to capture and store all carbon dioxide underground will, in fact, shut down coal plants across the country, which will, of course, drive up consumer electricity bills, and convert existing power plants to burn natural gas.

Given the volatility of the oil and gas market, and the instability in the Middle East and the rising cost of oil and natural gas, I believe we should reject policies which move us toward greater dependence on foreign sources of energy, and instead, embrace policies and encourage the use of our domestic resources, such as advanced clean coal technology demonstration projects.

The figures that I have from the Energy Information Administration in May of 2007, the cost per million Btu of oil is $7.66 per million Btus. Natural gas is $7.53, and coal is $1.73, so I think it is very evident, the cost differences in oil versus natural gas and coal. Today's hearing, of course, has shed some light on some of these issues, and also, brings out the fact that there are significant challenges to overcome, such as the readiness of the technology, the capital costs and long-term liability issues, which was touched on, and I think that we in the Congress must first address these issues before we can implement a CCS technology mandate.

With that, I would like to pose a few questions, and to try and clarify a few points. And Mr. Hill, in particular, I read your written testimony, and you state that carbon dioxide storage, also known as sequestration, is a technology that is available today, and I wanted to clarify a point, and to make certain that I understand, that you are referring to carbon sequestration technology for enhanced oil recovery. Is that correct?

Mr. HILL. No, I am not only referring to oil recovery. I think the technology for storing CO_2 in oil and gas reservoirs independent of enhanced oil recovery is available today, and I could point, I can point to the two well examples of where that occurs. Under the North Sea, the Sax Formation has been storing a million tons per year of CO_2 for ten years, and the Dust Development in Salah. It is also storing a million tons of CO_2 per year in the bottom of a gas reservoir.

Mr. COSTELLO. Now, is anyone currently capturing CO_2 underground, on a full, large-scale basis in the United States?

Mr. HILL. I am not aware of a full-scale application in the United States.

Mr. COSTELLO. Any of the other witnesses like to comment?

Dr. FINLEY. There is a plant in North Dakota that captures, from gasification, not from power production, but from gasification of coal, about 2.7 million tons a year, and it is shipped north to an enhanced oil recovery, and there is some testing as to how much will stay in that oil recovery field. So, that is one application.

Mr. COSTELLO. Let me, there is a bit of, we have a briefing for Members on the issue of coal and some of the challenges that we have, and in sum, people believe that the technology on a large-scale commercial basis is available today. Others say that it won't be available until the year 2020, and I wonder if, in particular, if any of the witnesses would like to comment, beginning with Dr. Finley.

Dr. FINLEY. Well, I think that would be a little pessimistic, in my view. I think, in view of the experience at, in Sleipner, which is the North Sea project, and Salah in Algeria, and the Weyburn Project, and the gas, natural gas storage, I think saying that we cannot do this until 2020 would be, in my view, a bit conservative.

Mr. COSTELLO. But would you agree that the technology is not on a commercial, full-scale basis, available?

Dr. FINLEY. Well, let me ask, are you speaking of the capture at the power plant, versus the ability to put it in the ground? Capture at the power plant is not available.

Mr. COSTELLO. Right.

Dr. FINLEY. That is correct. Ability to put it in the ground from a source, such as the Dakota Plains Gasification Plant, where we have a relatively pure stream available, that technology is there.

Mr. COSTELLO. And in your judgment, Dr. Finley, how long will it be—of course, it is your—you have got to give your best guess, before the technology is available to capture it at the power plant on-site?

Dr. FINLEY. I think we need probably, certainly, perhaps, six to ten years of intensive development to focus on that capture, basically to scale up some of the processes that we have seen today, and make them widely available.

Mr. COSTELLO. Two more quick questions, before I run out of time here. Would you agree that if, in fact, the Congress enacted a mandate to capture all, and to sequester underground, all CO_2 emissions, in the short-term, that that, in fact, would shut down most of the coal-fired plants in the United States today, and force them to convert to natural gas?

Dr. FINLEY. I think that would be a fair statement, yes.

Mr. COSTELLO. The last question, and I would love to hear from the other witnesses, but I am about out of time. Maybe we will have a second round, but Dr. Finley, some have suggested to Members of this subcommittee and to the Congress that, I have heard that we have a 250 year supply of coal. Others say that if we continue to use coal, and in fact, can sequester the CO_2 and move forward in using additional coal, that we are going to run out of coal in the short-term, and I wonder if you might give your estimate as to the coal supply of the United States.

Dr. FINLEY. Well, I think your number is correct, approximately 247 billion tons of defined reserves. We use about 1.1 billion tons a year, so that number is, indeed, very close. I think some of the

Sasol process, Sasol experience in South Africa suggests we can get about two barrels of hydrocarbon liquids for each ton of coal. I think we could easily move to perhaps produce as much as two million barrels per day of liquids from coal, and I still think we would easily have 100 years of coal to do that, in addition to having the coal available for electric generation that we would need over the next 100 years.

Mr. COSTELLO. I thank the Chair for being generous with my time, and thank the witnesses.

Chairman LAMPSON. Very welcome. We will get you back somehow. Mr. Neugebauer, you are recognized.

Mr. NEUGEBAUER. Well, I thank the Chairman, and like the distinguished Ranking Member, he is a real estate lawyer, and I am a real estate developer, so I don't know if I am going to be able to contribute much more than he did to this discussion.

I think I am going to start with a fundamental question and just for my own edification, if I had two electric power plants sitting side by side, one of them using natural gas, and one of them using coal, what is the ratio of CO_2 being emitted by those two plants? Mr. Dalton.

Mr. DALTON. You would roughly get about 2,000 pounds per megawatt-hour from a coal plant, conventional design or gasification design, without capture. And you would roughly get about 800 pounds per megawatt-hour from a natural gas plant, combined cycle.

Mr. NEUGEBAUER. So, it is a substantial difference.

Mr. DALTON. Correct.

Mr. NEUGEBAUER. And so, while we have got you in the queue, from your testimony, my impression is that post-combustion CO_2 capture not only reduces the output of pulverized coal, therefore, adding to the cost, but also, adds to the cost, due to the additional technology, transportation, and storage requirements. Is that accurate?

Mr. DALTON. That is accurate. We estimate that both the energy use and capture, and the compression energy, primarily, that is used to get the CO_2 up to the point where it becomes almost like a liquid, about half the density of water, it is transported through a pipeline, that energy can roughly run from, if you used today's technology, 20 to 30 percent of the overall energy of the plant. Again, we are looking at a lot of new technologies, both for compression and for capture, that will reduce that, but that is the kind of range that we are looking at.

Mr. NEUGEBAUER. So, I have got to have 120 percent more capacity with that process, to produce about the same amount of energy, without it, and so, and at the same time, I guess I am creating more CO_2 to be dealt with.

Mr. DALTON. And you are using more coal, correct.

Mr. NEUGEBAUER. So, what—for that to be a viable option for the future, what kind of research needs to begin to, or is research going on to try to make that a more efficient process?

Mr. DALTON. There is research going on. Carl Bauer referred to several pieces of that work that is going on. There is research going on on both the, if you will, the chemical plant that is in front of the power generation, which is gasification, and the chemical plant that is in the back of a more conventional plant, to capture the CO_2. Unfortunately, we haven't found anything yet that is the perfect absorbent material, that grabs it very easily, captures it very easily, and then, when you want it to, wants to let it go very easily. If it is easy on the capture side, it doesn't tend to want to let it go, and this is what takes all the energy, is to try and make it let go of the CO_2.

Mr. NEUGEBAUER. Yes, Mr. Rencheck.

Mr. RENCHECK. I would tell you that we are working on demonstration projects that would take those types of technologies that Stu was talking about from a pilot phase to an advanced phase, and we are hoping to get the energy penalties down to the 10 to 15 percent range. And the purpose of the demonstration is to do it at scale, and understand how it will behave on the back of the plant.

We are also looking at building IGCC plants which, in order to advance that technology, we are going to have to build four or five, six of these plants at a commercial scale, before we understand how they can more efficiently and more effectively be utilized.

OTHER USES FOR CO_2

Mr. NEUGEBAUER. Mr. Finley, you indicated in, that in my part of the world, West Texas, we have been using CO_2 for tertiary and secondary recovery of oil very, very successfully, and I assume without much hazard to the environment and to the region. I guess the other question is, what kind of research is going on where we could, rather than just putting this CO_2 in the ground and disposing of it, use CO_2 for other kinds of activities? Is any of that kind of activity going on?

Mr. BAUER. Yes, sir. There is some other work looking at using CO_2 for more rapid plant growth, algae growth, taking the algae as a quick uptake of CO_2, and then converting it to a biodiesel. There is a couple of different experiments around the country. Arizona Power Service is doing on a fairly large scale off of a plant, and they are moving it up to Four Corners area right now. There are a couple others I am aware of, where they use a pond rather than a bio-reactor, and those seems to hold promise, although the magnitude of the CO_2 generated across the Nation, that would only be one of the tools, it would not solve the problem totally. But they are looking at using CO_2 as a working fluid, to capture energy and move it elsewhere, and in fact, even oxy-combustion plants previously mentioned, looked at recycling CO_2 as part of the working fluid in operating the plant and keeping it cooler.

Mr. NEUGEBAUER. I thank you and thank the Chairman.

Chairman LAMPSON. Thank you, Mr. Neugebauer. Ms. Giffords, you are recognized.

WESTERN REGIONAL PARTNERSHIPS

Ms. GIFFORDS. Thank you, Mr. Chairman. I realize I wasn't here for the earlier questions and some of the testimony, but I hail from the great State of Arizona, where 90 percent of our electricity in the City of Tucson is generated from coal.

Over 50 percent of our state's energy is generated from coal, but we are the fastest growing state in the Nation, and new coal plants are being proposed for Southern Arizona and across the State as well.

I would like to see Arizona transition from coal to clean, renewable energy. However, I recognize that for the foreseeable future, that carbon capture and sequestration could help us reduce emissions in the meantime. So, I am curious to the barriers that we have in front of us in Arizona. I am curious about the environmental benefits and the costs, and also, some of the political obstacles that we have to overcome to make this a reality. And for anyone on the panel to answer, please.

Mr. BAUER. Well, if you are talking Arizona specifically, there are, as I am sure you are aware of the geological resources to put CO_2 in and store it, so those possibilities are there, but I think you made a very important point in your question, which is the political, and I might say the public receptivity to this. And this is one of the reasons the regional partnerships were formulated, to both understand the challenges in the geographic locations as well as the geologies, but also to work across the States that are part of it, to work with the communities and the academia to communicate what they find and what the challenges and what the opportunities are, so that the public acceptance and political acceptance would be there, should this process turn out, as it seems to be, to be a very viable solution.

So, I think part of it is education, and then part of that education, as you again wisely observed, is to go where we would like to go, as far as renewables, will take many decades to raise the quantity capability. How do we keep the economy viable while we do that? We are going to have to use what we have, which is basically coal, natural gas, and others, which are more carbon intensive.

Mr. DALTON. I would like to add that we have been working with the WESTCARB Regional Partnership in the West. There is some small-scale work being planned with Salt River Project as one of the organizations, working with, again this is the small-scale type of work that the regional partnerships has been excellent at setting out. It helps in understanding the mechanics, the monitoring, the verification. It helps in understanding the public perception issues as well, but there are geologies that run throughout certain parts of the West that are somewhat similar, and so, there should be quite a bit learned from any large-scale work that follows on wherever that is in the West, that the geologies are somewhat similar, to my understanding, as a chemical engineer, not as a geologist.

Mr. RENCHECK. And I would offer that the initial approach to improved efficiency as a coal generating plants are very important, and that is the reason for advancing technology such as the ultra-super critical plant, as well as the IGCC plants. And also, the existing fleet can also be improved from an efficiency perspective, but at times, it runs headlong into NSR regulations about improving border functionalities, so you could advance the existing fleet efficiency if we could get better clarity around new source review requirements.

FUNDING CONCERNS

Ms. GIFFORDS. And Mr. Chairman, if we could just follow up there. I am curious in terms of the actual costs, and where those costs would be shouldered. Is this—would—privately shouldered, publicly shouldered? Can the government step in and be helpful here?

Mr. RENCHECK. On the projects we are proposing, we are looking for a partnership between public and private funding. We are working also with technology providers who are also putting some of their money upfront in the development of technologies.

But it is quite expensive, and any one entity trying to push this forward by itself isn't going to be able to do it, so it does need to be a partnership. We do need to have incentives and funding to be able to progress technology, especially if we are looking for it to progress in an expedient manner.

Mr. DALTON. One other point, I am not sure if you were here for the testimony that I gave, but I mentioned that for a current technology on the pulverized coal plant, adding capture and storage might be an increase of 60 to 80 percent in the whole cost of generation, and for an IGCC, possibly 40 to 50 percent.

Now, a lot of research, federal and private efforts, are going toward reducing that cost, but right now, it is a very significant cost. Now, that isn't all of the retail cost of energy, obviously, but it could very significantly add, if it is today's technology.

Mr. HILL. I would just like to reinforce a couple of points. I think the government has a very important role to play here to enable this technology to happen, and to happen quickly, because time is of the essence, and the key ones, I think, are regulations and policy, and the need for public/private partnerships to co-invest and build these large, integrated projects.

They are very large capital outlays, but for that, you get very large reductions in emissions, and that is one of the unique things about this. You get very large reductions in emissions for one very large power plant. The downside is there are large capital outlays, and that is why you need to have this public/private partnership sharing the risk and sharing the development of this technology.

Ms. GIFFORDS. Chairman, if I can just follow up really quickly, Mr. Hill, can you give us very specific examples where public/private partnerships of this magnitude have been created around other industries, and areas that we can possibly learn from?

Mr. HILL. Well, I can give you a couple of examples where we were doing that on technology R&D. We have, we formed a public/private partnership, in fact, with the Department of Energy, probably about six or seven years ago now, where we really embarked upon a large program to develop new breakthrough technologies to reduce the cost of capture, and to prove that CO_2 could be stored safely. And that involved eight different companies, the Department of Energy, the European Commission, and the Norwegian government, who have been working together over the last six years at developing these technology, and it has now got us to the stage where we are ready to deploy and really demonstrate that at scale.

And I think that is a great example of where these public/private partnerships have got into action and produced some really tangible results.

Mr. RENCHECK. I would also offer that FutureGen is off to a good start with public/private partnerships, and it also has an international flavor, with participation from both the utility companies, coal companies, as well as governments.

Ms. GIFFORDS. Thank you, Mr. Chairman.

Chairman LAMPSON. You are welcome. Thanks, Ms. Giffords, and now, I will recognize Mr. Wilson.

CARBON CAPTURE FOR COAL TO LIQUIDS

Mr. WILSON. Thank you, Mr. Chairman. Gentleman, thank you for being here today. I represent the State of Ohio, or Ohio's Sixth Congressional District, which is coal country all along the Ohio River.

We have some interesting things going on there, and I would sort of like to present them to you, and be interested in your comments. And the panel in general, not just a specific person.

But we have a coal to liquid plant being proposed by the Baard Corporation, and it is going to be in Southern Columbiana and Northern Jefferson County along the Ohio River, but again, trying to tie together the Armed Services Contract, who will take the fuel for jet fuel, and be able to marry the two together, so that the fuel that is produced will have an automatic market for it. And again, trying to protect the investors, because we are looking at this thing long-term, not just something that if oil happens to hit $35 a barrel, we would have to be able to secure that investment.

That is one thing we are hearing. Another one of the concerns—and we are very excited about that, I might add—we also have a new coal-fired electric plant, a couple of them in play right now, and we have a couple of retrofits that AEP are doing along this Ohio River corridor.

The question or, to me, at least, the focus should be politically, or from the government, I should say, that if oil is the numbers that Congressman Costello said, which are just hugely different in what the coal can produce, it would seem to me that it would be wise to focus on the research and development of this at this point. It would be a much less expensive process than to continue sort of bantering around, for lack of a better term, but I am not sure, as a new Congressman, how we do that.

So, I am not sure that you have all the answers to those questions, but the other thing I am hearing is sort of a mixed message on how we do the sequestration. One of them is, in one of my areas, we have a new process called Powerspan, that has been put in, and they have drilled a 9,000 foot hole in Shadyside, Ohio there at the Burger Plant, to do sequestration, and my understanding is that the hole gets smaller as it gets deeper. I missed the first part, as far as pipeline, and I believe, Mr. Chairman, what we were saying is that this could be piped off into other areas. It doesn't have to be sequestered right onsite. Is that what I am hearing there?

The second thing, in ways of doing, or capturing the CO_2, was that of the algae process, and my understanding in dealing there with the people at the Voinovich Center at Ohio University, we are talking about the algae being applied to, at least this is my understanding of it, large sheets of it, if you will, and then, the carbon would be captured, and could somehow be reused, then, as a coke in producing steel. So, just some of those thoughts, if perhaps you could help me get some clarity on those. Mr. Rencheck.

Mr. RENCHECK. We are trying to develop an IGCC plant in Meigs County, Ohio, and had applied for, instead of tax credits, the incentive tax credits were only enough to cover two facilities. Two facilities won't be enough to keep the IGCC technology advancing. We need to have more funding in that area to be able to advance those plants.

As far as the Powerspan technology, it is very similar in the type of technology that is being produced by Alstom, who we have teamed with. It uses a chilled ammonia process for capturing CO_2. With the hope of the chilled ammonia process, it would reduce the overall power requirements of the plant, where Stu had said, upwards of 30 percent. Again, we are hoping to get it to a power penalty of around 10 to 15 percent, so it would advance that. And funding is needed to move these projects forward as well, if we are expecting to do this in a timely manner.

Mr. DALTON. Just to add, EPRI has also been working with the First Energy and Powerspan organization on their past work at the plant, and are involved in the planning for the next phase. This, again, is part of the regional partnership's work for injection of CO_2 at the Burger station. We think that there are a number of promising technologies. When we did a recent screening, we came up with about three dozen different promising technologies, and I am sure we didn't cover them all. There are some that are still at different stages of development.

This is an area where we think in parallel, not in the normal sequential arrangement of first you do the very small-scale work, then you do the pilot, then you do the large-scale up, we are going to have to work on multiple technologies at the same time, with an aggressive R&D effort, and we have been putting together some of these different plans for different technologies. I have in my hand one that is called CoalFleet, we have a program called that, RD&D, Augmentation Plan for Integrated Gasification Combined Cycle Power Plants. This has been put in the public domain. We have others that we have been working on for combustion. We believe that there are lots of things that need to be pressed right now, and pressed rapidly, as a public/private partnership.

Mr. RENCHECK. As part of a regional partnership, we have also drilled a 9,000 foot hole, just further down the Ohio River on the West Virginia side, being able to inject in both of those locations will give us a very good understanding of the rock formations and the capability in the area, in the regional area, of being able to sequester and store CO_2. So, we are looking to progress both of these projects as part of the regional partnership.

Mr. HILL. One of the things, I think your other question was focusing on R&D, and how you get actually things done at this scale. One of the things I can share with this hearing is what is being done in Europe, and the European Commission have set up a technology platform for zero-emissions power.

And I think two key things have come out of that, well, probably three key things have come out of that. One is a strategic research agenda, identifying all the research that is required. The second one, I think, is probably the most key, and that is a deployment strategy. What needs to get done to enable this to be in place and actually happening at commercial scale by a certain date? And the third one is setting a time when this will happen. And President Barroso, in the recent energy announcement, in fact, earlier this year, announced that by 2020, their plan is to have all fossil fuel power plants to require carbon capture and storage. Otherwise, they won't be permitted.

So, I think that was, and I mentioned this in my statement, I think it is really important to have a plan and a target, and a research and deployment strategy to enable you to achieve that objective. And one of the things the platform in Europe has done is brought together government, industry, utilities, all sectors of the industry, as well as equipment suppliers, academics and engineers, to work with us together, given that context and the goals that have been set.

Mr. RENCHECK. Not deploying further coal generation would inhibit and retard the ability to make that generation more efficient over time. As Mr. Dalton said, working the technologies in parallel will help us to get to the end solution faster. And as an example, in IGCC technology, its first commercial plants will occur with AEP and with, potentially, Duke Energy in Florida at a 600-megawatt level. They have not been built yet in the States. Not to continue developing that will slow the development of the gasification process technology, as it integrates with the combustion turbine process.

Mr. BAUER. If I may, Mr. Chairman. I know your red light is on, but——

Chairman LAMPSON. Go ahead.

Mr. BAUER. The DOE has had a plan, a roadmap, to go forward on these various challenges, and that is part of what the budget is based on. Of course, within the limited confines of funding availability, we have to make decisions, but the program both develops technologies for efficiency, as well as carbon capture, many of the things that were talked about, and have all been funded through the DOE. And the Powerspan technologies is in action, an NETL patent that was licensed to Powerspan.

On the algae issue, there are multiple ways to capture, and I think part of the things you are hearing, Congressman, are that there are multiple pathways forward, and our funding level constraint for parallel production is part of what is slowing the process down. So, going back to what my friends here are saying, trying to do things in parallel costs more instantaneously than doing things in series.

Chairman LAMPSON. Will you help us push for that additional funding?

Mr. BAUER. I will do what I can do.

Mr. WILSON. Thank you, gentlemen. Thank you, Mr. Chairman.

EFFICIENCY

Chairman LAMPSON. You are welcome. Thank you.

I have a number of questions, and if you all will keep your answers as short as you possibly can, I might be able to make it through all of them.

Mr. Bauer, how high do you believe the alternative combustion technologies DOE is researching, like oxy-combustion, can push the efficiency of coal, energy efficiency of coal?

Mr. BAUER. I think the issue on the oxy-combustion is we can get to several percentage points more efficiency. So, presently, the advanced power pulverized coal plants and IGCCs are equivalent in efficiency. I think with oxy-combustion, with some improvements in IGCC, they will both be in the 40 percent plus range over the next several decades. The thing that oxy-combustion provides is to the savings on the capture side, because now, then you have a higher concentration of CO_2 to capture from a pulverized coal unit, which is one of the advantages the IGCC has. They have a higher concentration of CO_2 in their stream. So, that begins to level those issues, as far as the price of operation.

Chairman LAMPSON. What progress has your Advanced Turbine Program demonstrated over the last ten years, and how close are these technologies to commercial scale application?

Mr. BAUER. I am going to ask Dr. Strakey to speak up, because that is his domain.

Mr. STRAKEY. I think the Advanced Turbine Program has made some remarkable progress. Originally, it was directed towards natural gas, and resulted in the H-class turbines, which are the most efficient, largest machines that are now being demonstrated at multiple sites around the world.

What we are trying to do in the coal program is take that same kind of technology, and adapt it for burning hydrogen, which is what you would have in a zero-emission plant. We are at some of the early stages of this work, and we hope to test some of that technology in FutureGen and other sites as well.

Chairman LAMPSON. How close to commercial scale application?

Mr. STRAKEY. Well, you can do it commercially now, but you will take a hit in terms of efficiency and emissions. So, the problem is how do you get back the couple points of efficiency that you would lose, and keep NO_X emissions very low, in the parts per million, couple parts per million range, so these plants can be sited anywhere in the U.S.

Chairman LAMPSON. Thank you. Mr. Rencheck, pulverized coal plants can achieve very high efficiencies with supercritical or ultrasupercritical steam pressures and temperatures that can reach 1,400 degrees Fahrenheit. You mention AEP's lead on development and deployment of more efficient coal power plants. I understand these extreme conditions can cause problems for the materials used in the power plants.

Who is conducting the primary research in these areas? Could you explain some of those material issues? Is there sufficient investment in these advanced technologies, either from the federal or private?

Mr. RENCHECK. The easiest way to explain it, an existing subcritical plant metallurgy, if you take it to the ultrasupercritical level that we are building right now, at a little over 1,100 degrees, the piping system that would normally last 75 years, in a supercritical plant would probably last about two. So, the metallurgy advancements to get the 1,400 degrees take quite a bit more research and development. It is primarily being pursued in Europe and Asia at this point in time, with a little funding in the U.S. It does need additional funding to be able to advance the metallurgies and technologies forward. There is some work going on with U.S. companies at this point, but it is not at a level that would advance it in the near-term.

Chairman LAMPSON. Mr. Dalton.

Mr. DALTON. I might add, under the sponsorship over the last about six years from the U.S. Department of Energy, the Ohio Coal Development Office and, with a team that includes the major U.S. boiler and now, turbine manufacturers, as well as specialists in EPRI as part of that team, and actually leads some of the technical work, we have been looking at some of those, at more advanced materials. There are very few materials, they also tend to be extremely high alloy, meaning high nickel, and for the same reason that we have taken the nickel out of the nickel in the U.S., it has gotten very expensive, it is very expensive for some of the alloy materials that are being used worldwide.

And this could significantly increase the cost, limit the number of alloys that could be used, so what we are looking at is the design methodologies, the tests in the field, and right now, there is not enough to bring that to the full-scale demonstration and deployment stage. We are really limited to the materials work in the work that we are conducting right now with DOE.

Mr. RENCHECK. And I would just like to add, the vintage, where we are looking to build here over the next several years, are already operating in Germany and Japan. We are behind.

Chairman LAMPSON. Mr. Dalton, in your testimony, you state that the significant energy consumption required by CO_2 separation processes and other emissions technologies can reduce a plant's electrical output by as much as 30 percent. Are there technologies that bring about enough production efficiencies so that the output losses from CO_2 separation are offset?

Mr. DALTON. The technologies for capture will almost always use a significant amount of energy. However, with the advancements of efficiency, through things like we were just talking about in the ultrasupercritical designs, the H turbine design, as one example, the ion transport membrane for oxygen separation, put these things together, and you get a more efficient front end, if you will, and a less parasitic load, or a less consumptive load on the back end. The overall, we believe, can mean that in 15, 20 years, you are back up to higher efficiencies again. But there is some consumptive use.

Mr. RENCHECK. I would like to make one point, as a retrofit on an existing plant, there are steam requirements for the existing technology that can get to the point where the plant physically won't work, and looking at some of our existing fleet, we believe we can only get enough steam off the steam cycle to capture a maximum of 50 percent carbon.

Chairman LAMPSON. Thank you. Would the work that Rick Smalley was doing at Rice University on carbon nanotechnology be—are you familiar at all?

Mr. DALTON. There again, there are at least three dozen new processes. Some of them propose very low energy use or using other forms of energy, such as the algal growth, which uses solar energy as part of the overall energy balance.

Chairman LAMPSON. Thank you all. You did good. Ranking Member Inglis, it is your turn.

BASIC ORGANIC CHEMISTRY

Mr. INGLIS. Thank you, Mr. Chairman. You know, necessity is the mother of invention, but it is also true that invention is propelled by a can-do spirit, and the neat thing about being here and hearing you testify is it is obvious that you are out there trying to solve these things, and so, we are very fortunate to have people like you doing what you are doing.

And maybe now you can explain to me the chemistry of carbon as said earlier I need to understand the science a little bit better. And maybe it would help me to have somebody tell me why it is that apparently, carbon wants to hook up with oxygen, right, and to get it to unhook, it takes some energy. But it must be possible to hook it with something else, to make it so that it isn't necessary to sequester it, or is it? I mean, is anybody working on something that would cause it to hook with something else, or is there nothing else that it likes to dance with?

Mr. BAUER. Well, as you said, Congressman, carbon and oxygen seem to like each other. H_2O, of course, is hydrogen and oxygen, but given the choice, more energy is released going to carbon dioxide than water, so in fact, shifting the gasification reaction to make more hydrogen, we pass steam through the system, and it hooks up with carbon monoxide, CO, to form water, I mean, to release hydrogen and have more oxygen and carbon combining, so the problem is that it is a lower state of energy required to have that bond of CO_2, so therefore, it is very hard to break it apart once it is joined.

It is possible, and in fact, some people are looking at taking CO_2, and using it to reverse the process, which will take energy, but if the economics are right, because of the pain of CO_2 in the world, you could possibly make a Fischer-Tropsch fuel out of that. That doesn't make sense in our present economy, because of the energy burden, but in the future, it may make sense, because the problem of CO_2 could be so great that the economics drive it the other way.

Mr. INGLIS. In which case, the carbon itself has some value, if you could isolate it.

Mr. BAUER. Yes, most of our fuel, and many other things that we use, carbon is an essential component of it.

Mr. INGLIS. Right.

Mr. BAUER. Even biomass is basically because of its carbon value that we use it.

CARBON CAPTURE

Mr. INGLIS. So now, maybe somebody can explain to me the thing that, I heard a presentation, and I didn't get it. So, maybe you can help me understand it, about how it is that, how pre-combustion CO_2 capture works.

Mr. RENCHECK. The bottom line is the, in the gasification process, you are taking coal, and you are not oxidizing it or burning it. It is more like it is smoldering, and with that, it produces a gas. The gas is primarily carbon monoxide and water, and it is under pressure, so it is a pressurized gas stream. The way you would do that, then, is as syngas goes forward, you shift it, and when you shift it through a Fischer-Tropsch process, it creates basically hydrogen and CO_2 in a pure stream. That CO_2 stream is pressurized already, so now, to pump it in the ground takes a lot less energy to store it. And then, the hydrogen is used in the combustion turbine to generate electricity.

Mr. DALTON. Let me try one other analogy. If I had a pretty good sized power plant, and I made this gas, I take a little bit of oxygen, not enough to burn it, but a little bit, I react it, I make something that looks like obsidian, volcanic glass, and it is inert. In the process, I make some hydrogen. The gas is under pressure, and it is high in concentration. I can literally put my arms around it, the size of a duct. However, at the back end of a power plant, the duct is more like the size of this room. It is very, very large, and you can just think it takes more equipment to literally get your arms around it. It is a much smaller, more compact, cheaper process to capture it in this pre-combustion, at pressure, with a higher concentration of CO_2, than it is to capture it afterwards. But do you want your chemical plant in front or in back, because they are both really chemical plants.

Mr. RENCHECK. And in the back process, it is basically at atmosphere conditions, and in the combined cycle process, it is compressed down at over 200 pounds, well over 200 pounds.

Mr. INGLIS. Mr. Hill, did you want to add something to that?

Mr. HILL. Yeah, I was just going to say the same thing from a different perspective. I mean, so pulse combustion is basically you burn the fossil fuels, and you have the exhaust gas, and you have to strip out the CO_2 from the exhaust gas, and the challenge is the CO_2 might only be a small part of that exhaust gas. It might 10 to 13 percent, if it is coal, or maybe three or five percent if it is gas, so you have got a huge volume, and you are trying to just pick out this 13 or three percent of CO_2. That is why that is quite tricky and quite expensive.

Pre-combustion is quite interesting, because pre-combustion is basically you are taking, you are developing a conversion process. You are converting gas, or you are converting a fossil fuel, putting it through a chemical conversion process to get some other state for that fossil you. And if you shift it the whole way by using steam, you get, eventually, CO_2 and hydrogen. But at other stages, there are other chemicals you can get before you get to the CO_2 and hydrogen, so it is quite a flexible technology. You could produce syngas, which you could actually put in the gas distribution system. You could produce other chemicals for chemical processing, as well as also making hydrogen for power.

So, pre-combustion is like a conversion process of fossil fuels to some other chemical state you would like that fossil fuel in. That does take a lot of energy, and the challenge is how you do that in the most cost-effective and efficient way.

Mr. INGLIS. And I assume the economics of that aren't quite there at this point. Is that right, or is that—how far away are we from the economics working on that sort of thing?

Mr. BAUER. Well, I think as both Stu and I have suggested, that with gasification, we are looking at 30 percent increase in the cost of electricity, so that gives you a sense of the economics. With an existing power plant, or even a brand new pulverized coal plant, not oxy-combustion, because the advantage of the oxy is you have a higher concentration of CO_2 again, because you don't put all the nitrogen in the rest of the air, and nitrogen is 70 percent of air.

So, that is like 50 to 70 percent, depending on the design of the plant, the substantial increase in the cost of electricity. And I think what is important to realize is that electricity is a low value product, and that is dispatches, whoever has the lowest price sells it, so for someone like AEP to make an investment on a plant that they couldn't dispatch early and recover costs, is a prohibitive hurdle to get over on their part, and that is part of the real issue on trying to move forward on this.

Mr. RENCHECK. I would just like to add as well, in the combustion process for oxy, coal, and IGCC, one of the biggest cost drivers or inefficiencies of that plant is actually making the oxygen for partial combustion. If you have to take air and separate the nitrogen and the oxygen, you run it through these gigantic compressors, some of which have 45,000 horsepower motors, bigger than probably the size of this room, you actually have to make sure your grid is reinforced, just so you can start these things. They are massive pieces of equipment, where some of the R&D work that Carl was talking about, with membrane technology, that could separate the air into nitrogen and oxygen, would make that process much more efficient, and much more economical over time.

Mr. INGLIS. Thank you.

Chairman LAMPSON. The Chair recognizes Mr. Udall.

H.R. 1933, THE DEPARTMENT OF ENERGY CARBON CAPTURE AND STORAGE RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACT

Mr. UDALL. Thank you, Mr. Chairman. I want to thank all you witnesses for being here. This is a really important and very interesting, it goes without saying, and just having been here a few minutes, it is clear that carbon capture and storage technology has real promise, particularly when it comes to utilizing these vast coal reserves that we have.

The DOE, as you know, has been researching this opportunity, I like to think of it in that regard, through its R&D program, but I think that Congress could do more to move the technology forward, and to that, I have recently introduced a piece of legislation, H.R. 1933, entitled the *Department of Energy Carbon Capture and Storage Research Development Act,* and what I would like to do is ask you, Mr. Bauer, starting with you, if you think this approach would help validate the technology, and move it towards commercialization.

I would, as you begin to speak, that Senator Bingaman has introduced a companion bill in the Senate, and there was a recent hearing that I am referencing with my question.

Mr. BAUER. Thank you, Congressman. I am familiar with 1933, and Senate 962, which are companion bills, and I think both bills provide a great deal of opportunity and are very positive towards dealing with these issues. I appreciate the recognition in the bill of the cost severity of trying to pursue this, which in the *Energy Policy Act of 2005,* has lower numbers, but this is a substantial problem, and so, the increase that you have recognized in the numbers are very good, the recognition of the regional partnership and the contribution they are able to make, I think is essential for us moving forward.

We have done a competitive process with both academia and environmental agencies, State agencies, and other agencies of the government, National Labs, and these regional partnerships have formed around that, and they have moved forward, and we are about to go into the phase of a million ton per year seven projects. I think you referenced that in the bill, and that is very exciting. So, overall, I think both bills provide the opportunity to move more rapidly and aggressively to overcome this challenge, and truly make it an opportunity.

Mr. UDALL. If anybody else on the panel would like to respond, I would welcome your thoughts.

Dr. FINLEY. I think 1933 also addresses that issue, and I would like to echo the sentiments that Mr. Bauer indicated. I think it is really important now that we move forward with the large-scale aspect of this, and that takes additional funding. The equipment, for example, even for a modest so-called large-scale test, 1,000 ton a day test, we need alone perhaps $12 to $14 million to install the equipment, large compressors that are very difficult to obtain. In fact, there is almost a year lead time just to order that equipment.

So, I think funding of this effort is extremely important. I think where there is a much greater recognition, as a result of the three IPCC reports that have come out since February, and I commend the effort to move this forward, particularly at the large scale, and to fund those efforts at that larger scale.

Mr. UDALL. Anyone else on the panel, or Mr. Bauer, do you want another——

Mr. BAUER. Yeah, I just wanted to add one other thing. I am trying to recall the many things in looking at the bill.

Mr. UDALL. Sure.

Mr. BAUER. And I am hoping I am not going to be out of turn in saying this, sir, but to do these projects is going to take more than three years, and I am sure you realize that and understand the process, but I didn't want to be remiss in suggesting that this would be the end of the story. I wish it would be, but it is probably seven to ten years, depending on how successful we are, to get to the end.

Mr. UDALL. Well, we are here to improve the legislation that has been proposed, and that makes complete sense that three years is not the only length of time we should be considering. Anybody else on the panel? Mr. Dalton.

Mr. DALTON. While I am not commenting on the bill itself, I would point out that capture is one of the big costs. It is almost as if you can look at two big issues, the cost in energy use of capture, and the effectiveness and assurance that you have storage well in hand. Those are the two big issues, and putting them together is one of the things that we think is very important as well. It is well enough to say that yes, I can, the car will perform this way, and the tires will perform that way, but you really do want to test them together. And in this case, I think that we want to make sure that large-scale capture and transport and storage are operated together, to make sure that there is good ability to do that, and operate the system that includes point-to-point transport, storage, as well as capture.

Mr. UDALL. Excellent point. Mr. Hill, and then we will come back to Mr. Rencheck.

Mr. HILL. Yes, I just want to reinforce that point. One of the things that BP has been very active over the last three or four years, is actually studying in a great deal of depth the integration of capture and storage systems. Through the two projects we have proposed, one in Peterhead in Scotland, and the other one at Carson in Long Beach, California.

And one of the key things we are learning is once we do this detailed work, is the integration of the various components of the overall process, in a way that will have a high degree of efficiency and a high degree of operability. So, I think there is only so much you can do by looking at individual components, and there really is a need now to build these very large-scale, integrated, commercial scale project to prove the integration of the various components, the operability, and the overall cost, and we will only discover it when we actually build them, and get really experienced, and I think that is the next step for us to take.

Mr. UDALL. Mr. Chairman, I see my time has expired. Is there time for Mr. Rencheck, or will we have another round, whatever works?

Mr. RENCHECK. We have provided projects that we are undertaking, and it will take it to scale, but as we talk about that, we need to also advance the combustion process and the pre-combustion process through ultrasupercritical technology or IGCC technology in addition to post-capture or capture and storage as well. Doing one without the other only thwarts the technology advancement going into the future.

MORE ON CARBON SEQUESTRATION RISKS

Mr. UDALL. These are very important points. Mr. Chairman, I had a couple other questions. I could submit them for the record, or I can direct them to the witnesses, depending on your timeframe.

If I could, and if you all discussed this before I arrived, what is the probability of the carbon release from geological storage sites, and what research and data are available to understand the environmental and human health and safety risks, and are there well established risk assessment methodologies for geological storage of CO_2? Easy questions, I am sure, given the smiles I see on people's faces, and I think Mr. Hill, Dr. Finley, and finely, and Mr. Bauer, you all have some qualifications to speak to. Dr. Finley, I am sorry, I have got, I see it is finely here and Finley here, so you correct me.

Dr. FINLEY. That is correct. Well, that is an extremely important issue, and it is, in fact, one that DOE has funded work. The National Labs, Lawrence Livermore and Lawrence Berkeley, have both been working on this for some time, independent of the Regional Carbon Sequestration Partnerships. We are in the process of uptaking some of that knowledge into our partnership.

I think you have to make the distinction between the so-called catastrophic release that is often cited in the press, the Lake Nyos example, I mean, I don't think we would decide to put CO_2, inject CO_2 beneath a volcanic lake, which is a high risk situation, obviously, and in this case, it was natural CO_2, in any event.

The risks are just beginning to be quantified. There is a lot of detail work now beginning to look at this, especially as we move forward with the large-scale injections per se. CO_2 is not flammable, it is not poisonous, but yet, you don't want to fill a room up with it, and walk into the room, and not move out. So, basically, you don't want it coming up, obviously, in people's basements and so forth.

My feeling as a geologist is that the risk, there is the natural risk posed by the geology itself, and then, there is a risk posed by the facilities, such as wells. I think the risk, if we carefully site these projects, and we assess the geology extremely carefully, with geophysics and seismic, look to make sure there are no faults or fracture zones, I think that risk is relatively low.

I think the larger risk, as we get many, many of these projects, is to make sure that the manmade infrastructure, the wells, pipelines, compressors, and so forth are done with the utmost care.

Mr. UDALL. Mr. Chairman, perhaps given the votes that have been called, we could submit the rest of the, others could have, on the panel, a chance to submit their answers for the record. And I have some additional questions I would like to submit for the record as well.

Chairman LAMPSON. Without objection, you may do so.

We want to thank all of you for appearing before the Subcommittee this afternoon. And under the rules of our committee, the record will be held open for two weeks for Members to submit additional statements and any additional questions that they might have for the witnesses.

And this hearing is now adjourned. Thank you.

[Whereupon, at 2:50 p.m., the Subcommittee was adjourned.]

Appendix 1:

Answers to Post-Hearing Questions

ANSWERS TO POST-HEARING QUESTIONS

Responses by Carl O. Bauer, Director, National Energy Technology Laboratory, U.S. Department of Energy

Questions submitted by Chairman Nick Lampson

Q1. Because the existing fleet of coal-fired power plants generate over 50 percent of the Nation's electricity and are one of the major emitters of greenhouse gases and other pollutants like mercury, how much funding will be dedicated to retrofitting the existing fleet to operate more cleanly and more efficiently in Fiscal Year 2008? How does this amount compare to the funds allocated to develop more efficient technologies for coal generating power plants in Fiscal Year 2007? Could you please elaborate on the specific efficiency retrofitting projects prioritized by the Department of Energy?

A1. The Innovations for Existing Plants (IEP) program supported technology development for criteria pollutant control technologies retrofits to existing conventional power plants, in anticipation of regulatory limits that are now being implemented through the Clean Air Interstate Rule and the Clean Air Mercury Rule. Because the industry now has strong regulatory drivers to complete the development on their own and commercially deploy such technologies, the IEP program is terminated. However, several programs are funded in the FY 2008 that target retrofit technologies for carbon capture, or that target technologies for new plants, but are also applicable to retrofit applications. In FY 2008, the Department plans to issue a Clean Coal Power Initiative (CCPI) Round 3 solicitation that would provide the opportunity for proposing projects to retrofit carbon capture technology, with ultra low emissions, such as mercury capture, to existing plants. However, since the selections require a competitive process it is not yet known how much will be awarded for retrofits. In FY 2007, the focus of the $414M coal R&D program is on the development of cleaner, more efficient technologies for coal generating power plants, and carbon sequestration. In each of the years FY 2007 and FY 2008 approximately $7M is being allocated to Advanced Research Materials to improve the efficiency of new and existing plants. The carbon sequestration program also funds development of post-combustion carbon capture technologies that could be applied as retrofits.

Q2. A 2007 interdisciplinary MIT Study "The Future of Coal" states that "It is critical that the government RD&D program not fall in the trap of picking a technology "winner" especially at a time when there is great coal combustion and conversion development activity underway in the private sector in both the United States and abroad." IGCC has received extensive DOE support through grants and FutureGen funding. What is the Department doing to advance oxyfuel technology, given that it can be used on all coal types on both existing and new plants and could be deployed soon?

A2. DOE does not pick technology winners. Rather, in response to environmental drivers such as climate change, the Department's research programs provide a portfolio of technology options that could be applicable under a variety of future regulatory and/or policy scenarios. This allows the marketplace, once regulations have been promulgated, to determine the most appropriate technologies for commercial deployment, based on performance and cost. Integrated gasification combined cycle (IGCC) technology is an important option being developed by DOE, applicable to a wide range of coal types. For example, the Department's Clean Coal Power Initiative includes a 285 MWe IGCC project to demonstrate technologies capable of major efficiency gains for low-rank, high-moisture, high-ash coals. Oxyfuel or oxy-combustion technology also is being investigated and DOE has several projects underway in this area.

Q3. The DOE National Energy Technology Laboratory in Albany, Oregon has developed the Integrated Pollutant Removal (IPR) technology. It is my understanding that tests show that when coupled with Oxyfuel, the hybrid Oxyfuel/IPR system can remove 90 percent of the mercury, 99 percent of the sulfur, 99 percent of the particulate including 80 percent of the PM2.5, and NO_X measured at the exit of the combustion process was 0.088 lbs/MMBtu. I further understand that the Oxyfuel/IPR system is also fully capture ready. Please explain any discrepancies the Department may have with the information I provided on the IPR system.

When does the Administration anticipate the IPR technology will move forward from development to commercial deployment? Will the Department need to dedicate additional funding to the IPR technology before it is ready for commercial *applications? To date, what level of funding has been used for the Department's development of the IPR technology?*

A3. Results from bench-scale development and testing and preliminary engineering analyses suggest that the IPR is a promising concept for reducing emissions from coal-fired power plants. Based on bench testing to date, Albany has achieved NO_X combustion levels at the exit of the combustion process of 0.088 lb/MMBtu; >99 percent of sulfur were removal; and >99 percent removal of particulate matter. However, it needs to be stressed that "bench-scale" results are not necessarily an accurate prediction of commercial results. Coupled with oxyfuel combustion to generate a more concentrated CO_2 flue gas, the IPR concept is one of a number of advanced carbon capture technologies being investigated under DOE's research program. As noted in your question, NETL's Albany research laboratory has been supporting the development of the IPR. Currently, through a Congressionally Directed Project, Jupiter Oxygen Corporation has teamed with NETL to integrate oxy-combustion with IPR at the Jupiter's test facilities in Hammond, Indiana. The timing for commercial deployment of oxyfuel/IPR technology is highly uncertain. It will be depend on the results from the Jupiter effort, any follow-on pilot and larger field testing over which the DOE program has some control; and on other factors outside the control of DOE. Finally as with many of the advanced carbon capture technologies the private sector also needs to resolve numerous issues before the oxyfuel/IPR concept is considered a viable, cost-effective CO_2 mitigation strategy. Because of all these uncertainties it is difficult to predict whether the Department will need to dedicate additional funding to the IPR technology before it is ready for commercial applications. To date, $3 million has been spent for the Department's development of the IPR technology.

Q4. Older natural gas fueled power plants built since 1950 surround many cities and contribute to NO_X and CO_2 pollution. Is it possible to retrofit these older gas plants with oxyfuel technology and if so, what would be the emissions reductions benefits? If the older gas plants were retrofitted with oxyfuel technology what steps would be necessary to provide for capture of the CO_2? What are the cost estimates for adding carbon capture technology to these facilities? Is the Department exploring other technologies to reduce emissions from gas fueled electric power plants?

A4. It might be possible to retrofit some older natural gas plants with oxyfuel technology, and there might be emissions reductions benefits to this approach. If gas plants were retrofitted with oxyfuel technology the necessary steps would begin with a feasibility study and comparison with alternative feasible alternatives. DOE has not performed cost estimates for retrofitting older natural gas plants with oxyfuel technology. The focus of DOE's carbon capture R&D effort is on technology applicable to coal-based power systems. This is because coal-fired power plants provide over half of the electricity generated in the United States, and their significant contribution to the United States' electricity grid is expected to continue through the better part of this century. It is recognized, however, that CO_2 is also emitted from other stationary fossil-fuel-combustion facilities, including natural-gas-fired boilers. As such, it is expected that the advanced post-combustion carbon capture technologies under development as part of DOE's Carbon Sequestration Program will have application to natural-gas-fueled power plants. Oxy-combustion is one such technology. The technical and operations issues associated with oxyfuel combustion, which DOE's R&D program is addressing, would be similar for a gas-fired boiler as for a coal-fired boiler. An important technical challenge is developing materials to withstand increased temperature in the furnace resulting from burning the fuel (coal or natural gas) in an oxygen-rich environment.

Flue gas recirculation is one approach being investigated to reduce the temperature, another approach is the development of new materials more resistant to high temperatures. Another critical issue associated with oxy-combustion is obtaining a large supply of low-cost oxygen. Current oxygen production systems, such as cryogenic, are prohibitively expensive. This is another area of research under DOE's Carbon Sequestration Program.

Appendix 2:

Additional Material for the Record

H.R. 1933

SECTION 1. SHORT TITLE.

This Act may be cited as the "Department of Energy Carbon Capture and Storage Research, Development, and Demonstration Act of 2007".

SEC. 2. CARBON CAPTURE AND STORAGE RESEARCH, DEVELOPMENT, AND DEMONSTRATION PROGRAM.

(a) AMENDMENTS.—Section 963 of the Energy Policy Act of 2005 (42 U.S.C. 16293) is amended—

(1) in the section heading, by striking "**RESEARCH AND DEVELOPMENT**" and inserting "**AND STORAGE RESEARCH, DEVELOPMENT, AND DEMONSTRATION**";

(2) in subsection (a)—

(A) by striking "research and development" and inserting "and storage research, development, and demonstration"; and

(B) by striking "capture technologies on combustion-based systems" and inserting "capture and storage technologies related to electric power generating systems";

(3) in subsection (b)—

(A) in paragraph (3), by striking "and" at the end;

(B) in paragraph (4), by striking the period at the end and inserting "; and"; and

(C) by adding at the end the following:

"(5) to expedite and carry out large-scale testing of carbon sequestration systems in a range of geological formations that will provide information on the cost and feasibility of deployment of sequestration technologies."; and

(4) by striking subsection (c) and inserting the following:

"(c) PROGRAMMATIC ACTIVITIES.—

"(1) FUNDAMENTAL SCIENCE AND ENGINEERING RESEARCH AND DEVELOPMENT AND DEMONSTRATION SUPPORTING CARBON CAPTURE AND STORAGE TECHNOLOGIES.—

"(A) IN GENERAL.—The Secretary shall carry out fundamental science and engineering research (including laboratory-scale experiments, numeric modeling, and simulations) to develop and document the performance of new approaches to capture and store carbon dioxide, or to learn how to use carbon dioxide in products to lead to an overall reduction of carbon dioxide emissions.

"(B) PROGRAM INTEGRATION.—The Secretary shall ensure that fundamental research carried out under this paragraph is appropriately applied to energy technology development activities and the field testing of carbon sequestration and carbon use activities, including—

"(i) development of new or advanced technologies for the capture of carbon dioxide;

"(ii) development of new or advanced technologies that reduce the cost and increase the efficacy of the compression of carbon dioxide required for the storage of carbon dioxide;

"(iii) modeling and simulation of geological sequestration field demonstrations;

"(iv) quantitative assessment of risks relating to specific field sites for testing of sequestration technologies; and

"(v) research and development of new and advanced technologies for carbon use, including recycling and reuse of carbon dioxide.

"(2) FIELD VALIDATION TESTING ACTIVITIES.—

"(A) IN GENERAL.—The Secretary shall promote, to the maximum extent practicable, regional carbon sequestration partnerships to conduct geologic sequestration tests involving carbon dioxide injection and monitoring, mitigation, and verification operations in a variety of candidate geological settings, including—

"(i) operating oil and gas fields;

"(ii) depleted oil and gas fields;

"(iii) unmineable coal seams;

"(iv) deep saline formations;

"(v) deep geologic systems that may be used as engineered reservoirs to extract economical quantities of heat from geothermal resources of low permeability or porosity;

"(vi) deep geologic systems containing basalt formations; and

"(vii) high altitude terrain oil and gas fields.

"(B) OBJECTIVES.—The objectives of tests conducted under this paragraph shall be—

"(i) to develop and validate geophysical tools, analysis, and modeling to monitor, predict, and verify carbon dioxide containment;

"(ii) to validate modeling of geological formations;

"(iii) to refine storage capacity estimated for particular geological formations;

"(iv) to determine the fate of carbon dioxide concurrent with and following injection into geological formations;

"(v) to develop and implement best practices for operations relating to, and monitoring of, injection and storage of carbon dioxide in geologic formations;

"(vi) to assess and ensure the safety of operations related to geological storage of carbon dioxide;

"(vii) to allow the Secretary to promulgate policies, procedures, requirements, and guidance to ensure that the objectives of this subparagraph are met in large-scale testing and deployment activities for carbon capture and storage that are funded by the Department of Energy; and

"(viii) to support Environmental Protection Agency efforts, in consultation with other agencies, to develop a scientifically sound regulatory framework to enable commercial-scale sequestration operations while safeguarding human health and underground sources of drinking water.

"(3) LARGE-SCALE CARBON DIOXIDE SEQUESTRATION TESTING.—

"(A) IN GENERAL.—The Secretary shall conduct not less than 7 initial large-volume sequestration tests, not including the FutureGen project, for geological containment of carbon dioxide (at least 1 of which shall be international in scope) to validate information on the cost and feasibility of commercial deployment of technologies for geological containment of carbon dioxide.

"(B) DIVERSITY OF FORMATIONS TO BE STUDIED.—In selecting formations for study under this paragraph, the Secretary shall consider a variety of geological formations across the United States, and require characterization and modeling of candidate formations, as determined by the Secretary.

"(C) SOURCE OF CARBON DIOXIDE FOR LARGE-SCALE SEQUESTRATION DEMONSTRATIONS.—In the process of any acquisition of carbon dioxide for sequestration demonstrations under subparagraph (A), the Secretary shall give preference to purchases of carbon dioxide from industrial and coal-fired electric generation facilities. To the extent feasible, the Secretary shall prefer test projects from industrial and coal-fired electric generation facilities that would facilitate the creation of an integrated system of capture, transportation and storage of carbon dioxide. Until coal-fired electric generation facilities, either new or existing, are operating with carbon dioxide capture technologies, other industrial sources of carbon dioxide should be pursued under this paragraph. The preference provided for under this subparagraph shall not delay the implementation of the large-scale sequestration tests under this paragraph.

"(D) DEFINITION.—For purposes of this paragraph, the term 'large-scale' means the injection of more than 1,000,000 metric tons of carbon dioxide annually, or a scale that demonstrably exceeds the necessary thresholds in key geologic transients to validate the ability continuously to inject quantities on the order of several million metric tons of industrial carbon dioxide annually for a large number of years.

"(4) LARGE-SCALE DEMONSTRATION OF CARBON DIOXIDE CAPTURE TECHNOLOGIES.—

"(A) IN GENERAL.—The Secretary shall carry out at least 3 and no more than 5 demonstrations, that include each of the technologies described in subparagraph (B), for the large-scale capture of carbon dioxide from industrial sources of carbon dioxide, at least 2 of which are facilities that generate electric energy from fossil fuels. Candidate facilities for other demonstrations under this paragraph shall include facilities that refine petroleum, manufacture iron or steel, manufacture cement or cement clinker, manufacture commodity chemicals, and ethanol and fertilizer plants. Consideration may be given to capture of carbon dioxide from industrial facilities and electric generation carbon sources that are near suitable geological reservoirs and could continue sequestration. To ensure reduced carbon dioxide emissions, the Secretary shall take necessary actions to provide for the integration of the program under this paragraph with the long-term carbon dioxide sequestration demonstrations described in paragraph (3). These actions should not delay implementation of the large-scale sequestration tests authorized in paragraph (3).

"(B) TECHNOLOGIES.—The technologies referred to in subparagraph (A) are precombustion capture, post-combustion capture, and oxycombustion.

"(C) SCOPE OF AWARD.—An award under this paragraph shall be only for the portion of the project that carries out the large-scale capture (including purification and compression) of carbon dioxide, as well as the cost of transportation and injection of carbon dioxide.

"(5) PREFERENCE IN PROJECT SELECTION FROM MERITORIOUS PROPOSALS.—In making competitive awards under this subsection, subject to the requirements of section 989, the Secretary shall give preference to proposals from partnerships among industrial, academic, and government entities.

"(6) COST SHARING.—Activities under this subsection shall be considered research and development activities that are subject to the cost-sharing requirements of section 988(b), except that the Federal share of a project under paragraph (4) shall not exceed 50 percent.

"(d) AUTHORIZATION OF APPROPRIATIONS.—

"(1) IN GENERAL.—There are authorized to be appropriated to the Secretary for carrying out this section, other than subsection (c)(3) and (4)—

"(A) $100,000,000 for fiscal year 2008;

"(B) $100,000,000 for fiscal year 2009;

"(C) $100,000,000 for fiscal year 2010; and

"(D) $100,000,000 for fiscal year 2011.

"(2) SEQUESTRATION.—There are authorized to be appropriated to the Secretary for carrying out subsection (c)(3)—

"(A) $140,000,000 for fiscal year 2008;

"(B) $140,000,000 for fiscal year 2009;

"(C) $140,000,000 for fiscal year 2010; and

"(D) $140,000,000 for fiscal year 2011.

"(3) CARBON CAPTURE.—There are authorized to be appropriated to the Secretary for carrying out subsection (c)(4)—

"(A) $180,000,000 for fiscal year 2009;

"(B) $180,000,000 for fiscal year 2010;

"(C) $180,000,000 for fiscal year 2011; and

"(D) $180,000,000 for fiscal year 2012.".

(b) TABLE OF CONTENTS AMENDMENT.—The item relating to section 963 in the table of contents for the Energy Policy Act of 2005 is amended to read as follows:

"Sec. 963. Carbon capture and storage research, development, and demonstration program.".

SEC. 3. REVIEW OF LARGE-SCALE PROGRAMS.

The Secretary of Energy shall enter into an arrangement with the National Academy of Sciences for an independent review and oversight, beginning in 2011, of the programs under section 963(c)(3) and (4) of the Energy Policy Act of 2005, as added by section 2 of this Act, to ensure that the benefits of such programs are maximized. Not later than January 1, 2012, the Secretary shall transmit to the Congress a report on the results of such review and oversight.

SEC. 4. SAFETY RESEARCH.

(a) PROGRAM.—The Assistant Administrator for Research and Development of the Environmental Protection

Agency shall conduct a research program to determine procedures necessary to protect public health, safety, and the environment from impacts that may be associated with capture, injection, and sequestration of greenhouse gases in subterranean reservoirs.

(b) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated for carrying out this section $5,000,000 for each fiscal year.

SEC. 5. GEOLOGICAL SEQUESTRATION TRAINING AND RESEARCH.

(a) STUDY.—

(1) IN GENERAL.—The Secretary of Energy shall enter into an arrangement with the National Academy of Sciences to undertake a study that—

(A) defines an interdisciplinary program in geology, engineering, hydrology, environmental science, and related disciplines that will support the Nation's capability to capture and sequester carbon dioxide from anthropogenic sources;

(B) addresses undergraduate and graduate education, especially to help develop graduate level programs of research and instruction that lead to advanced degrees with emphasis on geological sequestration science;

(C) develops guidelines for proposals from colleges and universities with substantial capabilities in the required disciplines that wish to implement geological sequestration science programs that advance the Nation's capacity to address carbon management through geological sequestration science; and

(D) outlines a budget and recommendations for how much funding will be necessary to establish and carry out the grant program under subsection (b).

(2) REPORT.—Not later than 1 year after the date of enactment of this Act, the Secretary of Energy shall transmit to the Congress a copy of the results of the study provided by the National Academy of Sciences under paragraph (1).

(3) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Secretary for carrying out this subsection $1,000,000 for fiscal year 2008.

(b) GRANT PROGRAM.—

(1) ESTABLISHMENT.—The Secretary of Energy, through the National Energy Technology Laboratory, shall establish a competitive grant program

through which colleges and universities may apply for and receive 4-year grants for—

(A) salary and startup costs for newly designated faculty positions in an integrated geological carbon sequestration science program; and

(B) internships for graduate students in geological sequestration science.

(2) RENEWAL.—Grants under this subsection shall be renewable for up to 2 additional 3-year terms, based on performance criteria, established by the National Academy of Sciences study conducted under subsection (a), that include the number of graduates of such programs.

(3) INTERFACE WITH REGIONAL GEOLOGICAL CARBON SEQUESTRATION PARTNERSHIPS.—To the greatest extent possible, geological carbon sequestration science programs supported under this subsection shall interface with the research of the Regional Carbon Sequestration Partnerships operated by the Department of Energy to provide internships and practical training in carbon capture and geological sequestration.

(4) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Sec-

retary for carrying out this subsection such sums as may be necessary.

SEC. 6. UNIVERSITY BASED RESEARCH AND DEVELOPMENT GRANT PROGRAM.

(a) ESTABLISHMENT.—The Secretary of Energy, in consultation with other appropriate agencies, shall establish a university based research and development program to study carbon capture and sequestration using the various types of coal.

(b) GRANTS.—Under this section, the Secretary shall award 5 grants for projects submitted by colleges or universities to study carbon capture and sequestration in conjunction with the recovery of oil and other enhanced elemental and mineral recovery. Consideration shall be given to areas that have regional sources of coal for the study of carbon capture and sequestration.

(c) RURAL AND AGRICULTURAL INSTITUTIONS.—The Secretary shall designate that at least 2 of these grants shall be awarded to rural or agricultural based institutions that offer interdisciplinary programs in the area of environmental science to study carbon capture and sequestration in conjunction with the recovery of oil and other enhanced elemental and mineral recovery.

(d) AUTHORIZATION OF APPROPRIATIONS.—There are to be authorized to be appropriated $10,000,000 to carry out this section.