EPA POWER PLANT REGULATIONS: IS THE TECHNOLOGY READY?

JOINT HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY &
SUBCOMMITTEE ON ENVIRONMENT

COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY
HOUSE OF REPRESENTATIVES

ONE HUNDRED THIRTEENTH CONGRESS

FIRST SESSION

October 29, 2013

Serial No. 113–51

Printed for the use of the Committee on Science, Space, and Technology

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

U.S. GOVERNMENT PRINTING OFFICE
85–277PDF WASHINGTON : 2013

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, SPACE, AND TECHNOLOGY

HON. LAMAR S. SMITH, Texas, *Chair*

DANA ROHRABACHER, California
RALPH M. HALL, Texas
F. JAMES SENSENBRENNER, JR., Wisconsin
FRANK D. LUCAS, Oklahoma
RANDY NEUGEBAUER, Texas
MICHAEL T. McCAUL, Texas
PAUL C. BROUN, Georgia
STEVEN M. PALAZZO, Mississippi
MO BROOKS, Alabama
RANDY HULTGREN, Illinois
LARRY BUCSHON, Indiana
STEVE STOCKMAN, Texas
BILL POSEY, Florida
CYNTHIA LUMMIS, Wyoming
DAVID SCHWEIKERT, Arizona
THOMAS MASSIE, Kentucky
KEVIN CRAMER, North Dakota
JIM BRIDENSTINE, Oklahoma
RANDY WEBER, Texas
CHRIS STEWART, Utah
VACANCY

EDDIE BERNICE JOHNSON, Texas
ZOE LOFGREN, California
DANIEL LIPINSKI, Illinois
DONNA F. EDWARDS, Maryland
FREDERICA S. WILSON, Florida
SUZANNE BONAMICI, Oregon
ERIC SWALWELL, California
DAN MAFFEI, New York
ALAN GRAYSON, Florida
JOSEPH KENNEDY III, Massachusetts
SCOTT PETERS, California
DEREK KILMER, Washington
AMI BERA, California
ELIZABETH ESTY, Connecticut
MARC VEASEY, Texas
JULIA BROWNLEY, California
MARK TAKANO, California
ROBIN KELLY, Illinois

SUBCOMMITTEE ON ENVIRONMENT

HON. CHRIS STEWART, Utah, *Chair*

JIM BRIDENSTINE, Oklahoma
F. JAMES SENSENBRENNER, JR., Wisconsin
DANA ROHRABACHER, California
RANDY NEUGEBAUER, Texas
PAUL C. BROUN, Georgia
RANDY WEBER, Texas
LAMAR S. SMITH, Texas

SUZANNE BONAMICI, Oregon
JULIA BROWNLEY, California
DONNA F. EDWARDS, Maryland
MARK TAKANO, California
ALAN GRAYSON, Florida
EDDIE BERNICE JOHNSON, Texas

SUBCOMMITTEE ON ENERGY

HON. CYNTHIA LUMMIS, Wyoming, *Chair*

RALPH M. HALL, Texas
FRANK D. LUCAS, Oklahoma
RANDY NEUGEBAUER, Texas
MICHAEL T. McCAUL, Texas
RANDY HULTGREN, Illinois
THOMAS MASSIE, Kentucky
KEVIN CRAMER, North Dakota
RANDY WEBER, Texas
LAMAR S. SMITH, Texas

ERIC SWALWELL, California
ALAN GRAYSON, Florida
JOSEPH KENNEDY III, Massachusetts
MARC VEASEY, Texas
MARK TAKANO, California
ZOE LOFGREN, California
DANIEL LIPINSKI, Illinois
EDDIE BERNICE JOHNSON, Texas

CONTENTS

October 29, 2013

Page

Appendix I: Answers to Post-Hearing Questions

Appendix II: Additional Material for the Record

EPA POWER PLANT REGULATIONS: IS THE TECHNOLOGY READY?

TUESDAY, OCTOBER 29, 2013

HOUSE OF REPRESENTATIVES,
JOINT HEARING WITH THE SUBCOMMITTEE ON
ENVIRONMENT AND THE SUBCOMMITTEE ON ENERGY
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY,
Washington, D.C.

The Subcommittees met, pursuant to call, at 10:07 a.m., in Room 2318 of the Rayburn House Office Building, Hon. Chris Stewart [Chairman of the Subcommittee on Environment] presiding.

LAMAR S. SMITH, Texas
CHAIRMAN

EDDIE BERNICE JOHNSON, Texas
RANKING MEMBER

Congress of the United States
House of Representatives

COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY

2321 RAYBURN HOUSE OFFICE BUILDING

WASHINGTON, DC 20515–6301

(202) 225–6371
www.science.house.gov

Subcommittee on Environment
and
Subcommittee on Energy

EPA's Power Plant Regulations: Is the Technology Ready?

Tuesday. October 29, 2013
10:00 a.m. – 12:00 p.m.
2318 Rayburn House Office Building

Witnesses

The Honorable Charles McConnell, Executive Director, Energy & Environment Initiative, Rice University

Dr. Richard Bajura, Director, National Research Center for Coal and Energy, West Virginia University

Mr. Kurt Waltzer, Managing Director, The Clean Air Task Force

Mr. Roger Martella, Partner, Environmental Practice Group, Sidley Austin

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

HEARING CHARTER

EPA Power Plant Regulations: Is the Technology Ready?

Tuesday, October 29, 2013
10:00 a.m. – 12:00 p.m.
2318 Rayburn House Office Building

PURPOSE

The Subcommittees on Environment and Energy will hold a joint hearing entitled *EPA Power Plant Regulations: Is the Technology Ready?* on Tuesday, October 29th, at 10:00 a.m. in Room 2318 of the Rayburn House Office Building. The hearing will cover what considerations the EPA relied in making its selection of best system of emissions reductions in the proposed New Source Performance Standards (NSPS) for electric generating units (EGUs). In so doing, the hearing will explore the technological basis for concluding that carbon capture and storage (CCS) is adequately demonstrated as a technology for controlling carbon dioxide emissions in full-scale commercial power plants. Further, the hearing will examine whether the rule promotes or deters technological development and American leadership in energy technologies. Fundamentally, this hearing seeks to answer the question: Has CCS technology been "adequately demonstrated?"

WITNESS LIST

- **The Honorable Charles McConnell**, Executive Director, Energy & Environment Initiative, Rice University
- **Dr. Richard Bajura**, Director, National Research Center for Coal and Energy, West Virginia University
- **Mr. Kurt Waltzer**, Managing Director, The Clean Air Task Force
- **Mr. Roger Martella**, Partner, Environmental Practice Group, Sidley Austin LLP

BACKGROUND

Regulatory Context:

Section 111 of the Clean Air Act (CAA) establishes a unique technology-based mechanism for controlling emissions from stationary sources. Section 111(b) provides authority for EPA to promulgate NSPS which apply to new and modified sources. Specifically, EPA is directed to set standards based on "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[1] In setting the standard EPA is given some flexibility in that "emission limits may be established either for equipment within a facility or for an entire facility."[2]

EPA first proposed a NSPS for emissions for carbon dioxide (CO2) from power plants in 2012. However, after more than 2.5 million comments on the original proposal, EPA decided that a new approach was warranted and rescinded the original proposal.[3]

Simultaneously, on September 20, 2013 Administrator Gina McCarthy announced EPA's re-proposed CO2 NSPS for new fossil fuel-based electric generating units (EGUs). "These proposed standards reflect separate determinations of the best system of emission reduction (BSER) adequately demonstrated for utility boilers and IGCC units and for natural gas-fired stationary combustion turbines."[4]

Under the proposal, EPA concluded that CCS has been adequately demonstrated as a technology for controlling CO2 emissions in full-scale commercial applications at coal-fired EGUs, while reaching the opposite conclusion—that CCS is not adequately demonstrated—in the case of gas-fired EGUs. Based on this determination, EPA proposed an emissions limit for coal-fired sources of 1,100 lbs of CO2 per mega-Watt-Hour (MWH) and proposed standards for natural gas combined cycle sources from 1,000 to 1,100 lbs CO2/MWH depending on the size and type of unit.[5] Electric Generating Units that primarily fire biomass are exempted from the proposed rule.[6]

In examining the regulatory impact, EPA asserted that "coal units built between now and 2020 would have CCS, even in the absence of this rule." In light of this modeling, "EPA projects that this proposed rule will result in negligible CO2 emissions changes, quantified benefits, and costs by 2022."[7] The proposal seeks comment.

Technical Background:

Carbon capture and storage (CCS) methods capture CO2 from fossil fuel combustion before it is released into the atmosphere and store it underground in geological formations. Unlike some emission control devices, CCS is not simply one piece of technology; it requires a system of coordinating elements for successful implementation. Broadly speaking, there are four links in the CCS chain: capture, compression, transportation, and storage. Each link in the chain poses separate and distinct challenges to the efficacy of the technology. Among these

[1] Clean Air Act § 111(a)(1), 42 USCA § 7411(a)(1) (2006).
[2] http://www2.epa.gov/sites/production/files/2013-09/documents/111background.pdf
[3] Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Proposed Rule, Preamble p. 14-5, Sep. 20, 2013.
[4] *Id.* at 15.
[5] *Id.* at 15-6.
[6] *Id.* at 30, fn. 8.
[7] *Id.* at 16-7.

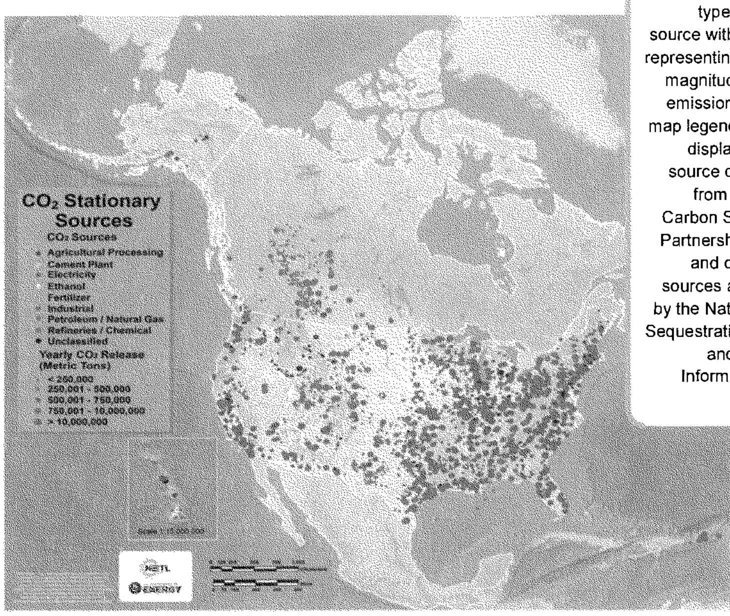
components, capture is the most technology-intensive and costly. Storage, on the other hand, poses the greatest liability and regulatory obstacles.

In the NSPS proposal, EPA notes four projects which—with significant governmental financial assistance—are designed to use some type of capture technology.[8] Although none of these projects have been completed, EPA anticipates at least one of these demonstration projects will be operational in the near future. EPA cites Southern Company's Kemper County Energy Facility in Mississippi, SaskPower's Boundry Dam CCS Project in Canada, The Texas Clean Energy Project in Odessa, and Hydrogen Energy California, LLC. Each of these projects, when completed, will utilize some elements of the CCS system EPA has selected in this proposal.

However, despite the promise of CCS technologies in power systems, currently there are no electric power plants operating with the CCS technology on a commercial scale.

CO_2 Sources

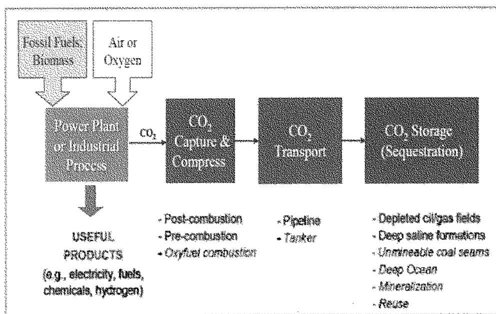
Where does CO2 come from? Nearly half of emissions come from mobile sources, like cars. But Stationary Sources also release CO2. Each colored dot represents a different type of stationary source with the dot size representing the relative magnitude of the CO_2 emission source (see map legend). This map displays stationary source data obtained from the Regional Carbon Sequestration Partnerships (RCSPs) and other external sources and compiled by the National Carbon Sequestration Database and Geographic Information System (NATCARB).



[8] EPA cites Southern Company's Kemper County Energy Facility, SaskPower's Boundry Dam CCS Project, Texas Clean Energy Project, and Hydrogen Energy California, LLC.

Capture

CO2 capture may be achieved through pre-combustion, post-combustion, or oxy-combustion technologies. **Pre-combustion** removal methods typically require the high-concentration of CO2 associated with expensive gasification systems. **Post-combustion**, on the other hand, utilizes nitrogen-based solvents to scrub the CO2 from the flue gas. However, because post-combustion capture requires substantial heat input to release the CO2 and regenerate the solvent, it results in significant reductions in overall plant efficiency and a substantial increase in cost. A third process, **oxy combustion**, requires expensive and energy intensive air separation units. While oxy systems hold promise, they are more experimental. Overall, while capture technologies exist, the new challenges associated with operating at a larger scale will not become clear until after full-scale deployment.



Source: E. S. Rubin, "Will Carbon Capture and Storage be Available in Time?" Proc. *AAAS Annual Meeting, San Diego, CA, 18-22 February 2010*, American Academy for the Advancement of Science, Washington, DC.

Compression & Transport

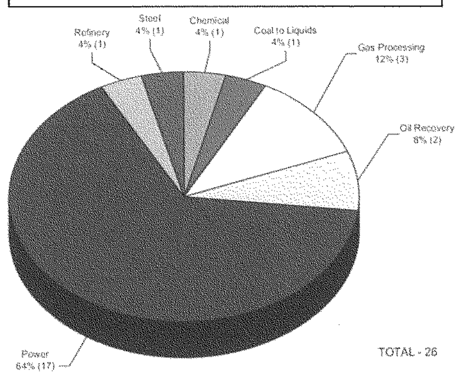
Once the CO2 is captured, it must be compressed. As with capture, compression is an energy intensive process. After compression, transportation to a storage site is required. Although dedicated CO2 pipelines have potential, technical challenges remain to ensure safe and reliable transport. Given the numerous policy and regulatory issues related to siting, permitting, and environmental requirements, creation of a full-scale CO2 pipeline infrastructure requires tremendous capital investment.

Storage

The critical final step in a CCS system is storage. However, permanently storing emissions is highly dependent on geologic systems. Geological storage is potentially available in deep saline formations, depleted oil fields, un-mineable coal seams, or for enhanced oil or gas recovery (EOR). However, lessons learned from failed storage sites in Africa demonstrate that maps of promising geologic formations do not always equate to locations where carbon storage can occur. Consequently, unresolved issues related to property rights acquisition, pore space management, regulatory structure, environmental protection issues, and liability remain a challenge. Significantly, EPA is unable to release operators from federal liability and litigation risk without legislative changes to existing environmental law.

Because of these challenges and the potential to offset the significant cost of CCS, the proposed rule focuses on the use of the captured CO2 for enhanced oil recovery (EOR). EOR has been used as a way to increase production in depleted oil fields by injecting CO2 into the oil deposit and pumping previously unrecoverable oil to surface. While EOR provides outstanding opportunities to increase oil production in some regions, many locations do not have access to an EOR market. Absent a robust EOR market, CO2 would simply be stored geologically.

According to the Global CCS Institute's 2013 report, seventeen (65 percent) of the 26 cancelled or delayed CCS projects are in power generation.



Future of CCS Demand:

As discussions of new climate strategies continue, pressure for additional CO2 restrictions will likely increase. Simultaneously, worldwide energy demand, particularly in emerging economies, is growing rapidly. Much of the current and future demand for energy will continue to be supplied by fossil fuels. Consequently, many projections suggest a strong long-term need for affordable technologies that can supply low-carbon energy from fossil fuels.

Additional Reading:

CONGRESSIONAL RESEARCH SERVICE, *Carbon Capture and Sequestration (CCS): A Primer*. July 16, 2013. Available at: http://www.crs.gov/pdfloader/R42532.

GLOBAL CCS INSTITUTE, *Global Status of CCS: 2013*. Oct. 10, 2013. Available at: http://www.globalccsinstitute.com/publications/global-status-ccs-2013/online/117741.

Hearing Charter, HOUSE SCIENCE, SPACE, AND TECHNOLOGY, SUBCOMMITTEE ON ENERGY AND ENVIRONMENT HEARING, *The Future of Coal: Utilizing America's Abundant Energy Resources*, July 25, 2013. Available at: http://science.house.gov/sites/republicans.science.house.gov/files/documents/HHRG-113-SY20-20130725-SD001%20.pdf.

U.S. ENVIRONMENTAL PROTECTION AGENCY, *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*. 40 CFR Part 60. Sep. 20, 2013. Available at: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

Chairman STEWART. The joint hearing of the Subcommittee on Environment and the Subcommittee on Energy will come to order.

Good morning, everyone. Welcome to today's joint hearing titled "EPA's Power Plant Regulations: Is the Technology Ready?" In front of each member are packets containing the written testimony, biographies and Truth in Testimony disclosures for today's witnesses.

Before we get started, since this is a joint hearing involving two Subcommittees, I want to explain how we will operate procedurally so that all Members understand how the question-and-answer period will be handled. After first recognizing the Chair and the Ranking Members of the Environment and Energy Subcommittees, we will recognize those Members present at the gavel in order of seniority of the full Committee, and those coming in after the gavel will be recognized in order of their arrival. And just as a side note, we had a Republican conference this morning, and that is going a little bit long. We expect other Members to be joining us shortly. And in the event that Ms. Lummis and others are not here for their opening comments, we will allow them to have that time allocated to them for their comments upon their arrival. I now recognize myself for five minutes for an opening statement.

I would like to thank the witnesses for being here today. I have had the chance to introduce myself and to meet you, and we appreciate your time and your sacrificing in attending with us, and we have an excellent panel before us, but I am disappointed EPA didn't accept our invitation to join us, and perhaps Ms. McCabe will be able to join us in the future hearing on this topic.

The significance of EPA's proposed New Source Performance Standards for new power plants simply can't be understated. As the first GHG standards for the statutory sources under the Clean Air Act, the rule does more than affect power plants. It sets the benchmark for standards affecting all industries, standards that will touch every aspect of our economy. Most troubling, however, is the proposal appears to be based on a hypothetical plant. This is a very dangerous precedent.

Under the Clean Air Act, setting the standards is basically a three-step process: first, establish the universe of adequately demonstrated technology; second, determine an achievable level based upon on that technology; and third, we consider the cost. In its proposal, EPA conveniently skips over step one. It then heavily focuses its analysis on modeling scenarios that project the answers to the steps two and three. These model-only-based arguments are outlandish to experts and engineers and to the general public. We don't need to look further than the botched-out rollout of healthcare.gov to appreciate the consequences of disregarding testing of a full-scale product. But EPA thinks it can get away with it due, primarily, I think to the court's deference.

But the focus of this hearing, and the first question the EPA must answer, is not what standards do we set or even is this cost-prohibitive? Instead, our hearing today focuses only on step one, and that is, is the technology ready? This question exposes the soft underbelly of the rule. When the facts and experts make clear the technology is not ready, there is no need to model emissions levels or ask economists to make projections.

To be clear, EPA relies on DOE modeling to conduct their analysis, and this is how they circumvent the step one "is it ready" question. They simply assume that it is ready and then they plow ahead. The model is only as good as the assumptions that go into it. Even a critical design review cannot account for irregular behavior in a full-scale product. Take, for example, the first Tacoma Narrows Bridge. Everything appeared to be operational until a 40-mile-an-hour wind toppled what was the third longest suspension bridge in the world.

Here, because the technology isn't ready, all of EPA's subsequent claims are purely hypothetical. Its claims are mere conjecture that ignores the fact that, in DOE's words, the technology is unproven.

After the Agency has finished looking into its crystal ball, analyzing an imaginary world, it tries to justify its claim of adequate demonstration with weak post hoc citations to cherry-picked literature, experiences with vastly scaled-down technology components and power plants that are under construction.

In order to comply with EPA's rule, carbon capture and sequestration is required. CCS, as it is commonly known, is not one piece of equipment; rather, is it a complicated system of many separate technologies. Each piece of this chain, which includes capture, compression, transportation and sequestration, must work in a seamlessly integrated fashion on a full-scale power plant. No CCS project in the world meets these criteria.

In its proposed rule, EPA points to several examples of fledgling CCS projects as proof that the technology is adequately demonstrated, but let us take a look at some of those examples. If you could look here to the screen, here are a few examples of the Texas Summit Clean Energy project, which in EPA's words is "under construction." My favorite picture, which is coming up, is at the project's web page, "small common grave by train tracks in Penwell." Actually, this is the only CCS currently occurring on the site.

Emissions modeling and economic projections based on a hypothetical plant are irrelevant. EPA's rule won't be implemented in a fairy tale world. This rule will affect real power plants and real people. This hearing is about what unicorns, Bigfoot, and the adequately demonstrated CCS for power plants all have in common: they are mere figments of the imagination.

Talk of emissions levels and cost based on a hypothetical modeling scenario is just a bunch of noise, a distraction from the fact that the technology isn't ready. EPA attempts to lawyer its way around this fact but ultimately, EPA cannot paper over the truth. To quote John Adams: "Facts are stubborn things."

I look forward to our experts' discussion today on this step one question: is the technology ready?

[The prepared statement of Mr. Stewart follows:]

PREPARED STATEMENT OF SUBCOMMITTEE ON ENVIRONMENT CHAIRMAN CHRIS STEWART

I would like to thank the witnesses for being here today. While we have an excellent panel before us, I am disappointed EPA didn't accept our invitation. Perhaps Ms. McCabe will be able to join us for a future hearing on this topic.

The significance of EPA's proposed New Source Performance Standards (NSPS) for new power plants cannot be understated. As the first GHG standards for stationary sources under the Clean Air Act, the rule does more than affect power plants. It sets the benchmark for standards affecting all industries—standards that will touch every aspect of our economy.

Most troubling, however, is the proposal appears to be based on a hypothetical plant. This is a dangerous precedent. Under the Clean Air Act, setting the standards is basically a three step process: First, establish the universe of "adequately demonstrated" technology. Second, determine an achievable level based on that technology. Third, consider the costs.In its proposal, EPA conveniently skips over step 1. It then heavily focuses its analysis on modeling scenarios that project the answers to the steps 2 and 3.

These model-only based arguments are outlandish to the experts, engineers and the public. We don't need to look further than the botched roll-out of healthcare.gov to appreciate the consequences of disregarding testing of a full scale product. But EPA thinks it can get away with it due to the court's deference.

But the focus of this hearing—the first question that EPA must answer—is not "what standards do we set?" or even "is this cost prohibitive?" Instead, our hearing today focuses on step 1: "is the technology ready?"

This question exposes the soft under-belly of the rule. When the facts and experts make clear the technology is not ready, there is no need to model emissions levels or ask economists to make projections.

To be clear, EPA relies on DOE modeling to conduct their analysis—that is how they circumvent the Step 1 "is it ready" question. They simply assume that it is and plow ahead. A model is only as good as the assumptions that go into it. Even a critical design review cannot account for anomalous behavior in a full scale product. Take for example the first Takoma Narrows Bridge. Everything appeared operational until a 40 mile-an-hour wind toppled what was the third longest suspension bridge in the world.

Here, because the technology isn't ready, all of EPA's subsequent claims—are hypothetical. Its claims are mere conjecture that ignores the fact that, in DOE's words, the technology is "unproven."

After the Agency is done looking into its crystal ball, analyzing an imaginary world, it tries to justify its claim of "adequate demonstration" with post hoc citations to cherry-picked literature, experience with vastly scaled down technology "components," and power plants "under construction."

In order to comply with EPA's rule, carbon capture and sequestration (CCS) is required. CCS, as it is commonly known, is not one piece of equipment; rather, is it a complicated system of many separate technologies. Each piece of this chain, which includes capture, compression, transportation and sequestration, must work in a seamlessly integrated fashion on a full scale power plant. No CCS project in the world meets these criteria.

In its proposed rule, EPA points to several examples of fledgling CCS projects as proof that the technology is adequately demonstrated. Let's take a look at one of those examples.

Here are a few pictures of the Texas Summit Clean Energy project, which in EPA's words is "under construction.

My favorite picture is at the bottom of the Project's web page—"Small common grave by train tracks in Penwell."

Actually, that is the only CCS currently occurring at the site.

Emissions modeling and economic projections based on a hypothetical plant are irrelevant. EPA's rule won't be implemented in a fairy tale world. This rule will affect real power plants and real people. This hearing is about what Unicorns, Bigfoot, and "adequately demonstrated" CCS for power plants all have in common—they are figments of the imagination.

Talk of emissions levels and cost based on a hypothetical modeling scenario is just a bunch of noise—a distraction from the fact that the technology isn't ready.

EPA attempts to "lawyer" its way around the facts. But ultimately, EPA cannot paper over the truth. To quote John Adams: "Facts are stubborn things; and whatever may be our wishes., our inclinations, or the dictates of our passion, they cannot alter the state of facts and evidence."

I look forward to our expert panel's discussion of this Step 1 question: Is the technology ready?

Chairman STEWART. With that, I now recognize the Ranking Member, Ms. Bonamici, for her opening statement.

Ms. BONAMICI. Thank you very much, Chairman Stewart and Chair Lummis, for holding this hearing today. And to our panel, welcome to the Committee on Science, Space, and Technology.

I join those who are very pleased by the proposal from the Administration and the United States Environmental Protection Agency to take the first steps to set carbon emission limits for all future natural gas and coal power plants. We have known for some time that dangerously high levels of carbon dioxide pollution are altering our planet's climate system. According to the latest statistics compiled by the EPA, American power plants released more than 2.4 billion tons of carbon dioxide into the environment in 2011. Fossil fuel power plants are responsible for a majority of these emissions, and coal-fired power plants emit more carbon dioxide than any other source.

Last month, the Intergovernmental Panel on Climate Change released the global comprehensive scientific assessment confirming that it is extremely likely that human influence has been the dominant cause of the observed warming since the mid-20th century. The report also confirmed that carbon dioxide increases are primarily the result of fossil fuel emissions, and have increased by 40 percent since the pre-industrial period. Addressing the effects of carbon pollution globally will require an international effort, but the United States can and must be a leader and set an example for other nations by reducing our own carbon pollution at home. We must do a better job of preventing the harmful effects of carbon dioxide emissions produced by natural gas and coal-fired power plants.

The coal industry's claim that the new carbon rule will kill jobs and bring down our recovering economy are scare tactics that have no basis in reality. The EPA proposal will not apply to existing power plants. The new rule will only apply to new coal-fired power plants that will be built in the future.

As we look forward to the EPA issuing the new carbon emissions standard, it is worth reminding ourselves of what we get with these standards: better air quality, which means better health for us, for our children, and for our grandchildren. In the four decades since it was signed, the Clean Air Act has saved thousands of lives and helped fuel job growth.

Additionally, and importantly, the passage of the Clean Air Act led to innovative advancements in technology. Environmental protection technology industries created innovations like catalytic converters, and sulfur dioxide and nitrogen oxide control technology. When the EPA took steps to require the application of these technologies, the industry made claims against those rules similar to the contentions that the coal industry is using today to undermine the carbon emission standard for new fossil fuel power plants: that our economy would be weakened and the industry would be devastated. And as we know, that did not come to fruition. Those industries adjusted and incorporated the technologies into their operations and went on to be more profitable than they had been, and we got cleaner air and healthier children.

The future of our planet and our environment depends on us making smart investments in innovative environmental protection technologies and reducing the amount of greenhouse gases we emit into our environment. The new EPA rule under the Clean Air Act will incentivize the development of these technologies that will in turn result in a safer, more secure and less carbon-dependent energy future.

And before I close, Mr. Chair, I want to clarify. It is my understanding that according to the EPA, they did offer to appear at a hearing in November. They were unable to appear today because once the government reopened after the shutdown which, as you know, lasted more than a couple weeks, they did not have enough time to prepare for today with the backlog from the shutdown. So I don't think they intended not to show; they did not get an invitation until September 27th, immediately before the shutdown.

So thank you, Mr. Chairman. I look forward to the testimony and answers to our questions, and I yield back.

[The prepared statement of Ms. Bonamici follows:]

PREPARED STATEMENT OF SUBCOMMITTEE ON ENVIRONMENT RANKING MEMBER SUZANNE BONAMICI

Thank you Chair Stewart and Chair Lummis, for holding this hearing today. And, to our panel of witnesses, welcome to the Committee on Science, Space, and Technology.

I join those who are very pleased by the proposal from the Administration and the United States Environmental Protection Agency to take the first steps to set carbon emission limits for all future natural gas and coal power plants. We have known for some time that dangerously high levels of carbon dioxide pollution are altering our planet's climate system. According to the latest statistics compiled by the EPA, American power plants released more than 2.4 billion tons of carbon dioxide into the environment in 2011. Fossil fuel power plants are responsible for a majority of these emissions, and coal-fired power plants emit more carbon dioxide than any other source.

Last month, the Intergovernmental Panel on Climate Change released the global comprehensive scientific assessment confirming that it is "extremely likely that human influence has been the dominant cause of the observed warming since the mid-20th century." The report also confirmed that carbon dioxide increases are primarily the result of fossil fuel emissions, and have increased by 40 percent since the pre-industrial period. Addressing the effects of carbon pollution globally will require an international effort, but the United States can and must be a leader and set an example for other nations by reducing our own carbon pollution at home.

We must do a better job of preventing the harmful effects of carbon dioxide emissions produced by natural gas and coal-fired power plants. The coal industry's claim that the new carbon rule will kill jobs and bring down our recovering economy are scare tactics that have no basis in reality. The EPA proposal will not apply to existing power plants. The new rule will only apply to new coal-fired power plants that will be built in the future.

As we look forward to the EPA issuing the new carbon emissions standard, it is worth reminding ourselves of what we get out of these standards: better air quality, which means better health for us, for our children, and for our grandchildren. In the four decades since it was signed, the Clean Air Act has saved thousands of lives and helped to fuel job growth.

Additionally the passage of the Clean Air Act led to important advancements in technology. Environmental protection technology industries created innovations like catalytic converters, and sulfur dioxide and nitrogen oxide control technology. When the EPA took steps to require the application of these technologies, the industry made claims against those rules similar to the contentions that the coal industry is using today to undermine the carbon emission standard for new fossil fuel power plants: that our economy would be weakened and the industry would be devastated. As we know, that never came to fruition. Those industries adjusted and incorporated the technologies into their operations and went on to become more profitable than they had ever been. And, we got cleaner air and healthier children.

The future of our planet and our environment depends on us making smart investments in innovative environmental protection technologies and reducing the amount of greenhouse gases we emit into our environment. The new EPA rule under the Clean Air Act will incentivize the development of these new technologies that will in turn result in a safer, more secure, and less carbon dependent energy future.

Chairman STEWART. Thank you, Ms. Bonamici, and regardless of the reasons why, we do look forward to subsequent conversations with the EPA, and we anticipate that they will be accommodating to us at that point.

The chair now recognizes the chairwoman of the Subcommittee on Energy, Ms. Lummis, for her opening statement.

Chairwoman LUMMIS. Thank you, Mr. Chairman and Ranking Member. Good morning, and thank you, witnesses, for joining us at today's hearing on carbon capture and storage technology. I do wish the EPA was here today, at least to listen to our concerns, and I consider an invitation extended on September 27th for a hearing that is occurring about a month later to be pretty good time to prepare, especially since it is their own rules that we are asking them to defend.

The EPA has proposed New Source Performance Standards for any future coal-fired power plant. These standards can be achieved only through the application of carbon capture and storage, a technology that is not currently in operation at a commercial-scale power plant anywhere in the world.

Instead of basing these requirements on technologies that are actually proven achievable on a commercial scale, EPA is redefining and stretching the requirement that technology be adequately demonstrated. This leaves many unanswered questions: Will the carbon capture technology function as intended when installed in full-scale plants? Is the pipeline infrastructure available for transportation on a large scale? And what is the liability for storage of carbon dioxide over the long term? EPA ignores many of these questions as the rule only impacts future coal plants.

The Obama Administration has spent much of the past few years casting coal as a villain. This regulation effectively bans the building of new coal plants, and fulfills President Obama's campaign promise to bankrupt coal companies.

But this hearing is not only about the proposed regulation. It is also about the legal precedent of mandating unproven technologies. The distinction the agency makes between coal and natural gas plants is dubious at best. By claiming that carbon capture technology is adequately demonstrated for coal, there is scant justification, legal or technical, for not requiring it for natural gas units. If EPA is allowed to twist the definition of "adequately demonstrated" to include yet-to-be-proven technologies for power plants, there is also little time—excuse me—there is also little to stop EPA from doing the same for other manufacturers like refiners, cement or steel plants. Not only would this throw our economy into a tailspin, it would force manufacturers to flee to countries with less restrictive environmental requirements, costing jobs and increasing global emissions.

Coal is our country's most abundant and affordable energy source. Thanks to the deployment of proven technologies, its production is much safer and environmentally sound, and the Clean Air Act has worked. It has produced cleaner air every year since it was passed. Coal is not only our country's most abundant and affordable energy source, one that the President is making clear that his goal is to apply standards to existing plants as well, thereby making it difficult for existing plants to stay in business. This policy of picking winners and losers, of saying we are going to have wind and solar energy but not fossil fuel energy or nuclear energy, even though those are the only ones sufficient to create baseload, is reckless, and it is dangerous for our country if we want to advance economically and create jobs and return to a sound economy.

I continue to support an all-of-the-above energy policy, not one based on politics, and all of the above means all of the above including fossil fuel and including wind and solar.

From an economic outlook, none of this should be taken lightly. Affordable, reliable electricity is the backbone of a healthy economy. Rising electricity prices affect everything, the cost of basic commodities, like food to our competitive position in the world. And because increasing energy prices act are like a regressive tax, they hit the poor and those on fixed incomes the hardest. Just ask any single mother who pulls up to a gas station when the price of gasoline hovers near 4 bucks.

America cannot afford to allow EPA edicts to control our energy policy. These new regulations will make life harder for working families, for single moms struggling to get by, and for anyone who lives paycheck to paycheck. This is something we should be guarding against, not encouraging.

I look forward to the hearing. I look forward to this panel of witnesses. I want to hear you discuss the development of this technology, its potential as well as its limitations. I also want to understand the impact this rule could have on future advances in carbon capturing and also conversion of coal to liquids and other opportunities that create a cleaner future for our country while enjoying and utilizing our ingenuity and our abundant coal resources. If you really want to see whether somebody is affected by coal, I strongly encourage you to go out around 12:30 on the west front of the Capitol today. There is an American energy jobs rally. There are coal miners and the companies they serve here on the Capitol steps, and if you think that it is not going to matter or whether you can pass regulations that the technology is unproven but will suddenly appear and the prices that won't go up and that coal plants will continue to be built and those jobs will still exist, try listening to the people on the Capitol steps here today who will prove you wrong with their real-life stories.

Thank you very much, Mr. Chairman. I yield back the balance of my time.

[The prepared statement of Mrs. Lummis follows:]

PREPARED STATEMENT OF SUBCOMMITTEE ON ENERGY CHAIRMAN CYNTHIA LUMMIS

Good morning and thank you for joining us for today's hearing on Carbon Capture and Storage Technology.

The EPA has proposed New Source Performance Standards (NSPS) for any future coal fired power plants. These standards can be achieved only through the application of Carbon Capture and Storage (CCS)—a technology that is not currently in operation at a commercial scale power plant anywhere in the world.

Instead of basing these requirements on technologies that are actually proven achievable on a commercial scale, EPA is redefining and stretching the requirement that technology be "adequately demonstrated." This leaves many unanswered questions: will the installment of carbon capture technology be functional? Are there plans for transportation on a large scale basis? What is the liability for storage of carbon dioxide over the long-term?

EPA would like Congress oversight of these standards to include only its impact on future coal plants. The Obama Administration has spent much of the past few years casting coal as a villain. This regulation effectively bans the building of new coal plants, and fulfills President Obama's campaign promise to "bankrupt" coal companies.

But this hearing is not only about the proposed regulation. It is also about the legal precedent of mandating unproven technologies. The distinction the agency makes between coal and natural gas plants is dubious at best. By claiming that carbon capture technology is adequately demonstrated for coal, there is scant justification—legal or technical—for not requiring it for natural gas units.

If EPA is allowed to twist the definition of "adequately demonstrated" to include yet-to-be-proven technologies for power plants, there is also little to stop EPA from doing the same for other manufacturers like refiners, cement or steel plants. Not only would this throw our economy into tail-spin, it would force manufacturers to flee to countries with less strict environmental requirements, costing jobs and increasing global emissions.

Coal is our country's most abundant and affordable energy sources. Thanks to the deployment of proven technologies, its production is safe and environmentally sound. The President has already made it clear that his goal is to apply these standards to existing plants as well. This policy of picking winners and losers through environmental regulations is reckless and dangerous. I continue to support an all-of-the-above energy policy, not one based purely on politics.

None of this should be taken lightly. Affordable, reliable electricity is the backbone of a healthy economy. Rising electricity prices affect everything—from the cost of basic commodities, like food—to our competitive position in the world. And because increasing energy prices act as a regressive tax, they hit the poor and those on fixed incomes the hardest.

America cannot afford to allow EPA edicts to control our energy policy. These new regulations will make life harder for working families, for single moms struggling to get by, and for anyone who lives paycheck to paycheck. This is something we should be guarding against, not encouraging.

I look forward to hearing the panel of witnesses discuss the development of this technology, its potential and limitations and the impact this rule could have on future advances. Thank you for joining us.

Chairman STEWART. Thank you, Ms. Lummis.

The Chairman now recognizes the Ranking Member of the Subcommittee on Energy, Mr. Swalwell, for his opening statement.

Mr. SWALWELL. Thank you, Chairman Stewart and Chairman Lummis, for holding this hearing, and I look forward to working with our witnesses today.

I do have to say, I think it is unfair, Mr. Chairman, to accuse the EPA of not accepting the invitation to be here today. That invitation was extended right before the shutdown and they have offered to appear in November. I look forward to having them here, but you can't turn off the power and then complain that no one answered the phone, and that is what I think is happening right here, and I think that is an unfair way to start this hearing.

Global climate change, though, is one of the greatest challenges that we face, and last month, the Intergovernmental Panel on Climate Change released a report which states with 95 percent certainty that human activities are responsible for climate change. This report was based on a rigorous review of thousands of scientific papers published by over 800 of the world's top scientists. The report also makes it clear that if we do not take steps to halt this damage and make this change, the repercussions for humans and the environment will be catastrophic. We need to move forward and take the necessary steps to combat the warming of our planet before these impacts become inevitable.

We know that humans are impacting the climate in a number of ways, through emissions from the vehicles we drive, deforestation and changes in agricultural practices among other things. But fossil fuel-based power plants are the biggest producers of greenhouse gasses, accounting for roughly a third of our total emissions last year.

I have repeatedly said, just as Chairman Lummis has, that I favor an all-of-the-above approach to energy production. As I often say, if we can make it safe, let us make it happen. But I have to make it clear that we must take steps to make sure that we are reducing greenhouse gas emissions and lessening their impact on human health, the environment and global change.

That is exactly what the proposed standards for new coal and natural burning gases aim to do, which is why I support their implementation. And like Ms. Bonamici, I want to reinforce that they will have no effect on existing plants, so we aren't going to see a wave of shuttered plants and massive layoffs as a result of their implementation, and if we can display the first slide? Slide number one that is going to be displayed shows all of the existing coal plants in the United States, approximately 600 of them. Slide two is a map of the United States, and it has on it all of the plants that are affected by these new standards. You don't need a magnifying glass to see that the number is zero. Zero plants are affected by these standards. Zero jobs today will be lost by these new standards. And I think it is important not to confuse the issue here.

There are in-depth discussions underway about establishing standards for existing plants, which the EPA currently plans to propose next June, and there are ongoing, extensive engagement with all of the stakeholders to make sure that those standards will be flexible and won't have negative effects on state economies and job creation. I think we also cannot discount the value of certainty. The fact that there was uncertainty in what the regulations were going to be was also affecting job creation in existing plants and plans for new plants, and now that we have standards, that lends certainty to the marketplace.

Finally, there is nobody I know in Congress who intentionally wants to destroy or kill a job. I think what we want to do here is to make sure that we have healthy air for our children to breathe, a healthy future, and mitigate the effects on the economy to the best degree possible, but if you want to count job-killing by the numbers, the cost of the government shutdown for 16 days: 120,000 jobs, $24 billion to our economy. There is no policy that we can create today or that the EPA has created today that will kill as many jobs as that or wreak as much havoc on our economy as that government shutdown, and I think if we want to compare the two, that is a stark, stark contrast.

Finally, my colleagues on the other side of the aisle often say that our children and grandchildren will be left holding the bag if we do not reduce our deficits and national debt, and something I greatly agree with them about, but I think similarly, future generations will be the ones who will suffer if we do not take important and meaningful steps to confront climate change, but in this case, as the global scientific community has made clear again and again, the consequences of our inaction will be much, much more severe.

And with that, Mr. Chairman, I yield back the balance of my time.

[The prepared statement of Mr. Swalwell follows:]

PREPARED STATEMENT OF SUBCOMMITTEE ON ENERGY RANKING MEMBER ERIC SWALWELL

Thank you Chairman Stewart and Chairman Lummis for holding this hearing, and I also want to thank the witnesses for their testimony and for being here today.

Global climate change is one of the greatest challenges that we face. Last month, the Intergovernmental Panel on Climate Change released a report which states with 95 percent certainty that human activities are responsible for climate change. This report was based on a rigorous review of thousands of scientific papers published by over 800 of the world's top scientists. The report also makes it clear that if we don't take steps to halt this change, the repercussions for humans and the environment will be catastrophic. We now need move forward and take the necessary steps to combat the warming of our planet before these impacts become inevitable.

We know that humans are impacting the climate in a number of ways—through emissions from the vehicles we drive, deforestation, and changes in agricultural practices among other things. But fossil fuel-based power plants are the biggest producers of greenhouse gasses, accounting for roughly a third of our total emissions last year.

I have repeatedly said that I am for an "all of the above" approach to energy production as we transition to clean energy technologies. But I have also made it clear that, as part of this "all of the above" approach, we must take steps to ensure that we are reducing greenhouse gas emissions and lessening their impact on human health, the environment, and the global climate. That is exactly what the proposed standards for new coal and natural gas burning plants aim to do, which is why I support their implementation. And, like Ms. Bonamici, I want to reinforce that these are only proposed standards for any new plants that may be built and will have no effect on existing plants, so we aren't going to see a wave of shuttered plants and massive layoffs as a result of their implementation. There are in-depth discussions underway about establishing standards for existing plants, which the EPA currently plans to propose next June, and there is ongoing, extensive engagement with all stakeholders to make sure that those standards will be flexible and won't have negative effects on state economies and job creation.

It has been my hope that Congress would act on this issue immediately. Unfortunately, too many of my colleagues choose to ignore the scientific consensus that human beings are playing a significant role in the warming of our planet, so I'm not expecting that much will be done legislatively to sufficiently address this issue anytime soon. The President made it clear in his State of the Union Address back in January that, in the absence of Congressional action, his Administration was going to take the lead in efforts to reduce greenhouse gas emissions. These proposed standards reflect that commitment, and I fully support the President in this effort.

My colleagues on the other side of the aisle often say that our children and grandchildren are going to be left holding the bag if we don't reduce our deficits and the national debt, and I agree that it would be irresponsible of us not to take serious steps to put our fiscal house in order. Similarly, future generations will be the ones who will suffer if we don't take immediate and meaningful steps to confront climate change, but in this case—as the global scientific community has made clear again and again—the consequences of our inaction will be far more severe.

Chairman STEWART. Thank you, Mr. Swalwell.

Very quickly, we understand that there are differences of opinion and we can discuss or argue among ourselves whether the EPA had adequate time, some of us feel that they did, others may disagree with that. What is really clear is that in a pattern that has been established for more than just this hearing but for, frankly, for as long as I've sat in this chair, we have had to struggle to get them to come and to participate in many of our hearings, and this is just another example of that. But as I said earlier, we look forward to working with them and getting their representatives to come and meet with us.

With that, we will now turn to the Chairman of the full Committee, Chairman Smith, for his opening statement.

Chairman SMITH. Thank you, Mr. Chairman.

Today's hearing will allow us to hear from top experts in energy and environmental fields and examine important technical issues associated with EPA's new power plant regulations.

In the regulatory process, it is often difficult to separate technical issues from legal issues, and the technology question we focus on here today is also ultimately a legal question.

If you take a look at the EPA's rule on air quality standards, the proposal looks more like a legal brief than a rule about protecting the air. It appears the EPA is up to an old legal trick: if you can't win the argument on the merits, start arguing about the definition of words.

In this proposal, the EPA redefines the law to accommodate its ever-expanding regulatory agenda. By redefining what the term "adequately demonstrated" means in the Clean Air Act, the EPA is making another major power grab, one that reaches well beyond coal. That is because the New Source Performance Standards for power plants is the first greenhouse gas standard under the Clean Air Act. Consequently, it sets the precedent for all other sources, and underpins everything from the price we pay at the pump to the cost of electricity and food.

If the EPA continues to play fast and loose with the law, we can expect to see more costly, heavy-handed rules that risk jobs and economic growth. Working families will bear these costs.

Even more troubling is the way this proposal appears to intentionally block the courts from reviewing the rule. By claiming that no one will build coal-fired power plants anyway, the EPA wants to prevent the courts from reviewing the rule on its merits.

Our founders recognized that elections alone may not provide adequate protection for the liberties they fought so hard to establish. They made sure that the Constitution provides a means for the American people to obtain a fair hearing before impartial judges. One of the most underrated rights Americans enjoy today may be the right to judicial review. This proposal is an attempt to prevent judicial review. Americans deserve to understand exactly what this proposal would do and retain the right to challenge it.

Thank you, Mr. Chairman. Before I yield back, let me apologize at the outset. I have another committee that is in the middle of marking up legislation that I will go to and another committee is also having a hearing, so I will be shuttling back and forth but appreciate your holding this hearing. It is a very, very important one. Yield back.

[The prepared statement of Mr. Smith follows:]

PREPARED STATEMENT OF FULL COMMITTEE CHAIRMAN LAMAR SMITH

Today's hearing will allow us to hear from top experts in energy and environment fields and examine important technical issues associated with EPA's new power plant regulations.

In the regulatory process, it's often difficult to separate technical issues from legal issues. And the technology question we focus on here today is also ultimately a legal question.

If you take a look at the EPA's rule on air quality standards, the proposal looks more like a legal brief than a rule about protecting the air.

It appears the EPA is up to an old legal trick: If you can't win the argument on the merits, start arguing about the definition of words.

In this proposal, the EPA re-defines the law to accommodate its ever-expanding regulatory agenda. By re-defining what the term, "adequately demonstrated," means in the Clean Air Act, the EPA is making another major power grab—one that reaches well beyond coal.

That's because the New Source Performance Standards for power plants is the first greenhouse gas standard under the Clean Air Act. Consequently, it sets the precedent for all other sources, and underpins everything from the price we pay at the pump to the cost of electricity and food.

If the EPA continues to play fast-and-loose with the law, we can expect to see more costly, heavy-handed rules that risk jobs and economic growth. Working families will bear these costs.

Even more troubling is the way this proposal appears to intentionally block the courts from reviewing the rule. By claiming that no one will build coal-fired power plants anyway, the EPA wants to prevent the courts from reviewing the rule on its merits.

Our founders recognized that elections alone may not provide adequate protection for the liberties they fought so hard to establish. They made sure that the Constitution provides a means for the American people to obtain a fair hearing before impartial judges.

This may be one of the most under-rated rights Americans enjoy today: the Right to Judicial Review.

This proposal is an attempt to prevent Judicial Review. Americans deserve to understand exactly what this proposal would do and retain the right to challenge it.

Chairman STEWART. Thank you, Mr. Chairman, and you are welcome to participate as much as you can. Thank you.

If there are Members who wish to submit additional opening statements, your statements will be added to the record at this point.

[The prepared statement of Ms. Johnson follows:]

PREPARED STATEMENT OF FULL COMMITTEE RANKING MEMBER EDDIE BERNICE JOHNSON

I want to thank Chairman Stewart and Chairwoman Lummis for holding this hearing to discuss the EPA's proposal to set national carbon emission limits for new natural gas and coal power plants. I also want to thank the witnesses for being here today to provide their input on this important topic.

The benefits from the Clean Air Act are countless; they come in the form of lives saved, reductions in illnesses, technological advancements in environmental protection, and economic growth. I join my colleagues Ms. Bonamici and Mr. Swalwell in expressing my approval of the Obama Administration's and the EPA's first steps toward protecting future generations from the harmful effects of carbon pollution that threatens our health and is changing our climate system. And, they are making those steps by advancing clean energy technologies. We would all prefer to address these important issues with common sense legislation, but until we can agree on both sides of the aisle that climate change is a real and pressing problem, bi-partisan collaboration on solutions does not appear to be possible.

Throughout history industry has often resisted addressing environmental problems that emerge as a result of a greater scientific understanding of our impact on the environment and our health. And, in many of these cases, they simply will not do so without regulatory intervention and proper government oversight. I challenge industry leaders to be a helpful partner in reducing our carbon emissions going forward. If they will, we can have both a cleaner environment and a strong economy.

Chairman STEWART. As our witnesses should know, spoken testimony is limited to five minutes, after which the Members of the

Committee have five minutes each to ask you questions, and your written testimony will also be included in the record of the hearing.

And I would like now to introduce our witnesses today, and I will introduce you individually. We will turn the time over to you for five minutes, then I will introduce the next witness.

Our first witness is the Hon. Charles McConnell, Executive Directive at the Energy and Environment Initiative, Rice University. Previously, Mr. McConnell served as the Assistant Secretary for Fossil Fuel at the U.S. Department of Energy. At DOE, he was responsible for the strategic policy, leadership, budgets, project management, research and development of the Department's coal, oil and gas and advanced technology programs, and the National Energy Laboratory's Technology Laboratory. Prior to joining DOE, Mr. McConnell served as Vice President of the Carbon Management at Battelle Energy Technology. And Mr. McConnell, we turn the time over to you now for five minutes for your opening statement.

TESTIMONY OF THE HON. CHARLES MCCONNELL, EXECUTIVE DIRECTOR, ENERGY & ENVIRONMENT INITIATIVE, RICE

Hon. MCCONNELL. Thank you. It is an honor to participate at this hearing and have the opportunity to have a fact-based discussion about the science of CCS technology. I might also add, it is refreshing to prepare my remarks today without any OMB oversight.

Let me start by saying that we do have a problem. CO_2 capture, utilization and storage technology is a requirement to meet greenhouse gas standards. It is a requirement to meet New Source Performance Standards, and it has not been commercially demonstrated at scale and cannot be deemed demonstrated technology.

CCS is an environmental solution. It is an energy security issue, and it is also about economic competitiveness. All three of these things contribute to our success as a Nation. CCS has the potential to make us stronger and more successful as long as we don't forfeit that potential by rushing deployment of a technology that is not yet ready.

The world is and will remain dependent for many decades to come on fossil fuels to provide low-cost, available and reliable energy. The International Energy Agency has already projected by 2050 the world's demand for energy will double. One point seven billion people in the world today live in energy poverty. And yet by 2050, because we will need every single megawatt, megatherm and energy source available to us, we will still have 85 percent of our energy in the world provided by fossil fuels. So having fossil technology isn't an option, it is a requirement, as is an all-of-the-above strategy.

Commercial CCS technology is not available to meet the EPA's proposed rule. The cost of capture technology is much too high to be commercially viable, much the same as the economic threshold similar to subsidized carbon-free alternatives such as solar, wind, et cetera. We are investing in all of the above across the board because it is critical to our future.

In June, the Administration released its Climate Action Plan, a comprehensive program of domestic GHG emission reductions. The President's plan can only be achieved through the broad deployment of low-cost, commercially viable technology for capturing and permanently and safely storing CO_2 from all fossil sources.

But it is about energy security as well. CCS is necessary to assure a sustainable, diversified domestic energy portfolio for our energy security. It enables a true all-of-the-above energy portfolio. It is also a business strategy. CCS, or CCUS, where the U means utilization of CO_2 for purposes such as enhanced oil recovery, create a marketplace for implementation of these applications. It leads to broad deployment and it also gives us a commercial and business background to bring that technology to the marketplace. CO_2 EOR has been practiced in this country for over 50 years very successfully, and it includes the safe, long-term permanent storage of CO_2. But as I said, the technology isn't ready yet. The technology exists for separation and capture of CO_2 at the plant but it increases the cost of generated electricity by as much as 50 to 80 percent, and that depends on the power plant or the industrial application in which it is being used. CO_2 pipeline and transmission systems are mature but they face incredible siting difficulties for expansion of this marketplace.

DOE's regional carbon sequestration partnerships must continue to develop the needed database to help analyze the success of this deployment, and of course, the injection of CO_2 faces regulatory barriers as well: unresolved property rights, long-term liability issues, all of the issues that in many cases the EPA is very involved in and needs to be supportive of to allow this technology to move forward.

But the technology is being demonstrated. It is successfully deployed in some early first-of-a-kind projects but it is clearly not ready. It is really that simple. Focusing other questions are hypothetical but not about the demonstrated results of these plants or projects or the technology associated with it. The technology can be made ready over time, and will have to have the support of the EPA as well as the marketplace and industry.

To summarize, in my opinion, it is disingenuous to state that the technology is ready, and at the same time, starve the R&D programs for our Nation's energy security, global competitiveness or our global leadership in terms of economic performance. Thank you.

[The prepared statement of Hon. McConnell follows:]

U.S. House of Representatives Committee on Science, Space, and Technology Subcommittees on Environment and Energy

EPA Power Plant Regulations:

Is the Technology Ready?

Oct 29, 2013 10:00 a.m.

The Honorable Charles D. McConnell
Executive Director, Energy and Environment Initiative (e2i)
Rice University

RICE

Thank you for the opportunity to address this very important topic.

Carbon Capture and Storage as well as Carbon Capture Utilization and Storage (CCS/CCUS) are critically important to our nation, and I am glad Members of Congress are taking the time to understand the state of today's technology. CCUS is both an environmental solution and an important component of a business strategy. It is a business strategy that allows companies to meet EPA greenhouse gas (GHG) regulations, increase domestic oil production, and create domestic jobs by means of CO_2-EOR. CCUS also is necessary to assure a diversified domestic energy portfolio for energy security. It also helps minimize future rapid escalations in electricity prices, allowing a real "All of the Above" energy portfolio that includes our most abundant domestic resources – clean fossil energy from coal, oil, and natural gas.

Studies have verified that implementation of CCUS technology is necessary to comply with EPA's proposed New Source Performance Standard (NSPS) regulation and meet the GHG targets necessary for limiting CO_2 emissions to our atmosphere. However, commercial CCUS technology currently is not available to meet EPA's proposed rule. The cost of current CO_2 capture technology is much too high to be commercially viable and places the technology at similar economic thresholds of alternative clean, carbon-free energy alternatives currently being subsidized.

CCUS is also necessary to achieve President Obama's June 25th Climate Action Plan, a comprehensive program of domestic GHG emission reductions, adaptation measures, and international activities to address climate change. Global climate change, as the name indicates, must be addressed globally in order to make a difference. The world is and will remain dependent on fossil fuels for many decades to come to provide low cost, readily available and reliable energy.

The President's Plan can only be achieved through the broad global deployment of low cost, commercially viable technology for capturing and permanently and safely storing/utilizing CO_2 from all fossil energy sources. Technology exists for separation and capture of CO_2 at the plant, but it increases the cost of generated electricity by about 80%. CO_2 pipeline technology is mature, but can face siting issues. While injection of CO_2 into deep geologic storage formations is being evaluated, it has only been done successfully on a relatively small scale at a few sites around the globe. And the Department of Energy's (DOE) Regional Carbon Sequestration Partnerships are still developing the needed data base to help analyze the success of its deployment. Saline injection also faces regulatory barriers, such as liability for leakage extending 50 years beyond the time injection ceases, and unresolved property rights issues. CO_2 injection into oil bearing geologies for Enhanced Oil Recovery (EOR) has been practiced safely for over 50 years. Although the geologies are known to have permanence for storage, the long-term measurement, monitoring, and verification of these geologies has not been practiced for CO_2 storage.

DOE, in partnership with industry, is pursuing a research, development, and demonstration (RD&D) program to address all of these issues, especially CO_2 capture cost reduction, but affordable solutions may be decades away with the current level of funding and resultant R&D strategy. Moreover, the timing of retirement of existing coal-fired units, based on age and regulatory pressures, and the modest amount of new domestic power plant capacity resulting in part from the weak economic recovery, could lead to further delays in commercializing this necessary technology in our country. Internationally, however, the drive to provide electricity to those in developing nations is in full force and the year-over-year demand for coal globally is up 20% due to the pressure to eliminate energy poverty.

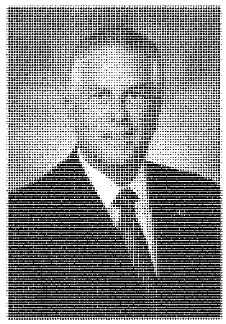
The DOE's coal research and development funding levels must be increased to enable the pursuit of demonstration projects to move transformational, low cost CCUS technology from the laboratory to the commercial marketplace in a timely manner. The sequester and persistently low budget request numbers have resulted in cuts to coal R&D at rates significantly lower than other DOE programs. An additional $100 million per year directed at low-cost, transformational CCUS could enable the demonstration of commercially viable CO_2 capture technology within ten years. While a considerable amount of technical risk would be required to undertake a program with this short of a schedule, it can be done.

Such risk could be made manageable through the build-out of DOE's extensive scientific and engineering CCUS database, along with the scaling and system integration experience provided by the major CCS demonstration projects – such as the Kemper Project, scheduled to go on line in 2014.

These demonstration projects were funded with stimulus dollars. However, the stimulus dollars were focused on near term jobs creation and had associated "sunset clauses" not typically part of demonstration program funding. Sunset clauses force the demonstration of first of kind technologies on an "artificial" legislated schedule – not a schedule determined by the management of risks associated with the scaling and integration of complex new technologies and the acquisition of financing for multi-billion dollar first-of-a-kind plants. While a large amount of stimulus monies were provided, they were sufficient to cover only about 20% or less of the costs of many of the major fossil/CCS/CCUS power plant demonstration projects. This required DOE's project partners to acquire billions of dollars in financing for technically and financially risky projects during a period that the U.S. was going through a deep recession – not easily done. This takes much time and effort to accomplish. The stimulus funding sunset provisions scheduled for September 2015 allow for very little time to secure such financing and many good projects could be lost as a result. The Congress may wish to consider extending the sunset provisions and also allowing DOE to transfer stimulus funding between ongoing projects to maximize success.

It is obvious that there is a need for continued funding as is defined by technologies that are not deemed to be "commercially available." To summarize, in my opinion, it is disingenuous to state that the technology is "ready" and it is wrong to underfund to assure failure if the true goal is "All of the Above."

Charles D. McConnell



Charles D. McConnell is Executive Director of Rice University's Energy and Environment Initiative, a university-wide integration of science, engineering, economic analysis, policy and social sciences to address the diverse issues and challenges associated with energy security, affordability and environmental sustainability. The effort is designed to partner with industry and external stakeholders and position Rice as an impartial broker that combines technology and policy to create a sustainable energy platform for excellence in resource utilization and environmental stewardship.

A 35-year veteran of the energy industry, McConnell joined Rice in August 2013 after serving two years as the Assistant Secretary of Energy at the U.S. Department of Energy.
At DOE, McConnell was responsible for the strategic policy leadership, budgets, project management, and research and development of the department's coal, oil and gas, and advanced technologies programs, as well as for the operations and management of the U.S. Strategic Petroleum Reserve and the National Energy Technologies Laboratories.

Prior to joining DOE, McConnell served as Vice President of Carbon Management at Battelle Energy Technology in Columbus, Ohio, where he was responsible for business and technology management, including leadership of the Midwest Regional Carbon Sequestration Partnership.

McConnell also spent 31 years with Praxair, Inc., providing business leadership and strategic planning to the global hydrogen business, refining and chemicals markets, enhanced oil recovery, carbon dioxide management and the full range of energy technology R&D activities.

McConnell has held a number of board positions including chairmanships of the Gasification Technologies Council and the Clean Carbon Technology Foundation of Texas. McConnell holds a bachelor's degree in chemical engineering from Carnegie-Mellon University (1977) and an MBA in finance from Cleveland State University (1984).

Chairman STEWART. Thank you, Mr. Secretary.

Our second witness today is Dr. Richard Bajura, Director of the National Research Center for Coal and Energy at West Virginia University. And Doctor, did I pronounce your name correctly?

Dr. BAJURA. Yes, sir.

Chairman STEWART. Thank you. He has spent the past 21 years facilitating research programs in energy at West Virginia University, and during this time he developed and managed eight major interdisciplinary and interinstitutional research programs addressing a wide range of energy applications from research extraction to alternative fuels. And Doctor, we turn the time over to you now.

TESTIMONY OF DR. RICHARD BAJURA, DIRECTOR, NATIONAL RESEARCH CENTER FOR COAL AND ENERGY, WEST VIRGINIA

Dr. BAJURA. Thank you, Mr. Chairman. Thank you for inviting me.

I consider coal to be a valuable resource and I believe we should maintain technology options to keep it as part of our energy future. As proposed, I think the EPA regulations will stifle coal's continued involvement.

I will summarize my comments in terms of lessons and observations that we have gained over the years of using coal technologies. Pulverized coal technologies are mature, integrating gasification and combined cycle technologies. There are only nine of them operating on coal in the world and only four in the United States. We have also learned that performance degrades with scale-up. What we learned in the laboratory doesn't always hold true when we go into the full-scale system. Many gremlins occur. Also, we have observed that delays in implementing projects, financing, technology costs and meeting schedules are important in determining the deployability of a technology.

The next topic deals with first-of-a-kind and nth-of-a-kind technologies. Over the years, we have developed what I will call learning-curve theory. What we find is the most expensive plant occurs on the first edition. By the time we get to the nth edition, the technology is mature and costs are reduced. Learning-curve technology for coal uses a factor that they call .06, which means that by the time you get to mature technology, you have reduced the cost by 25 percent. In the case of the Kemper plant, a $4 billion program, 25 percent reduction is $1 billion. Also in the case of Kemper, we are talking about $8,000 a kilowatt for the cost of the plant versus $1,000 a kilowatt for a natural gas combined cycle plant.

Coal is different from gas. Coal comes in three typical forms: bituminous, subbituminous and lignite. Natural gas, you can buy it anywhere. It is the same thing. Also, when you look at the deployment of technologies, what I learned on my technology is different from what you learn on your technologies. I don't share my results. As a result, while we might say we have different examples of technologies, they are almost first of a kind because they don't share the technology, they have different systems they apply to different coal. Technology integration is also important. We have to integrate a plant that has a new component with a pipeline, with a reservoir, and in many cases with the grid because we have to integrate the up-and-down performance of coal plants that might need changed from baseload to intermittent or peaking time of the situation.

In terms of the demonstrations that we have talked about that relate to this hearing, there are nine demonstrations that are referenced. Three relate to chemicals production. Two are IGCC plants. One is them is based on the Kemper plant, which has not demonstrated, and the other one is a first of a kind as well. Saline aquifers are the kind of aquifers that I think we are looking at with future-gen deployments, and there is only one example of that, and that future-gen plant is not going to be onboard until 2017.

We have heard that capture technology is very expensive for coal plants. Capture technology for the most part is based on amines. We know that works. But these technologies were developed for chemical plants where the products that you sell can justify the extra cost they would need to use those technologies. It is very expensive for a standalone coal plant.

Also, we have issues concerned with legal and societal issues that also affect the cost of a plant and must be addressed. Cost and feasibility are not necessarily demonstrated. We can't find guarantees for the projects that we would want to put in place, and I am concerned with the legislation in the way it is proposed, it will stifle development and planning for new plants, and without a driver, there will be no technology developed. Our friends in China are very interested in developing coal-based technologies, they have strong government support and they are ahead of us in chemicals production, in power generation, and in their next five-year plan, they will be ahead of us in CCS deployment. We require strong Federal support to maintain coal's presence in the marketplace, and I believe Congress and the Federal Government and the Executive Branch should be more supportive of coal and maintaining it as part of our mix.

In summary, I don't think the technologies that we are discussing are ready for deployment in the sense of being fundable by financiers or getting guarantees. I believe that if we are not keeping coal in our future mix, we will run out of workforce. People like me are getting older. And I believe Federal support will help us to achieve the kind of goals that we want in introducing new technologies. Thank you.

[The prepared statement of Dr. Bajura follows:]

West Virginia University

Office of the Director
National Research Center For Coal and Energy
Richard A. Bajura

October 27, 2013

Representative Chris Stewart
Chairman
Representative Suzanne Bonamici
Ranking Member
Subcommittee on Environment
Committee on Science, Space
and Technology
U. S. House of Representatives
2321 Rayburn House Office Building
Washington, D. C. 20515-6301

Representative Cynthia Lummis
Chairman
Representative Eric Swalwell
Ranking Member
Subcommittee on Energy
Committee on Science, Space
and Technology
U. S. House of Representatives
2321 Rayburn House Office Building
Washington, D. C. 20515-6301

Testimony on

Technological Requirements for Meeting New Source Performance Standards (NSPS) for Emissions of Carbon Dioxide from Electric Generating Units (EGU)

Presented by
Richard A. Bajura
Director
National Research Center for Coal and Energy
West Virginia University

October 29, 2013

Members of the Subcommittees on Environment and Energy:

Thank you for the opportunity to offer testimony on the New Source Performance Standards (NSPS) being considered by the U. S. Environmental Protection Agency (EPA) under Section 111 of the Clean Air Act of 1970.

EPA identified the following key factors in their criteria for the proposed rulemaking:

- Feasibility – whether the system of emissions reduction is technically feasible
- Costs - whether the costs of the system are reasonable
- Size of the Emissions Reductions – amount of CO2 emissions reduction resulting from the system
- Technology Development – whether the system promotes implementation and further development of technology

Suite 113 385 Evansdale Drive West Virginia University P. O. Box 6064 Morgantown, West Virginia 26506
NRCCE Director's Office Phone: 304 / 293-7030 Bajura Direct Line: 304 / 293-6034
NRCCE Director's Office Facsimile: 304 / 293-3749 Web Address: http://www.nrcce.wvu.edu
NRCCE Main Switchboard Telephone Number 304 / 293 2867

My testimony will focus on coal-fired electricity generation. Topics discussed are lessons learned about technology development, the stage of development of CCS (carbon capture and storage) technologies, technology development in other nations, and the need for federal support for research and demonstration projects.

Lessons Learned in Technology Development

Coal Plant Deployments and Performance

Thomas Sarkus of the National Energy Technology Laboratory (NETL) provided an overview of the U. S. Government's program in developing Clean Coal Technologies in a presentation at the 2013 Pittsburgh International Coal Conference. [1]

He noted that pulverized coal boilers were commercialized in the 1920s and 1930s, and that there are about 5,000 units operating world-wide with approximately 1,100 operating in the U. S. Fluidized bed coal combustion boilers were commercialized in the 1970s-1980s, and there are around 500 units operating world-wide with about 150, mostly small, units in the U.S. However, for Integrated Gasification Combined-Cycle (IGCC) coal power plants, there are only nine units operating world-wide and only four in the U. S.

He also shared his experience as a project manager for demonstration projects. He observed that technology performance often degrades with scale-up. In other words, a technology that looks promising in a small laboratory setting may not achieve the predicted operating performance at commercial scales. We often discover that new factors arise in larger systems that were not apparent in laboratory experiments. Also, project financing, cost of a system, and meeting construction schedules are all important considerations in determining if a technology is ready for commercial deployment.

First and N^{th} of a Kind Plants

In studying the development of technology for full scale systems that are deployed in large numbers such as the 5,000 pulverized coal plants referenced above, engineers have been able to quantify concepts that are called technology learning curves. Typically the highest cost for a full scale unit is the first of a kind (FOAK). As more copies of the same design are built and debugged, the performance of the design will generally improve and the cost for construction and operation will decrease. EPA is counting on the learning curve effect in making its projections for future performance and cost of CCS-based coal plants in establishing the proposed emissions limits on coal systems.

Care is needed, however, in in defining FOAK units and NOAK (N^{th} of a kind) units. Large scale units are usually based on a particular manufacturer's technology. Observations in the DOE/NETL-34/042211 report [2] illustrate the example that although gasification technologies are similar, it is unlikely that one vendor will share its experience with rivals. They comment that the E-Gas IGCC system (Conoco-Phillips technology) proposed for the Excelsior project is only a second of a kind

[1] Thomas Sarkus, Lessons Learned from U. S. Government Support of Clean Coal Technologies, International Pittsburgh Coal Conference, 2013, Beijing
[2] Quality Guidelines for Energy System Studies – Technology Learning Curve (FOAK and NOAK), DOE/NETL-341-042211, January, 2012 National Energy Technology Laboratory

IGCC based on the Wabash project experience. Little or no benefit will accrue to the E-Gas designers from the Pinion Pines (KRW technology) plant that failed, the Polk (GEE technology) in Florida, or the Buggenum and Puertollano (Shell) projects. Since the Excelsior project did not go forward to construction, of the nine IGCC plants cited by Sarkus above, it is possible they could all be FOAK plants. In this case, we would have only one, high-cost demonstration of each type that still has many major design parameters to be worked out to bring costs down and performance up to the values for an Nth of a kind plant.

We must also recognize that, unlike natural gas that is readily available nationally as a uniform commodity, coal varies from region to region in its characteristics. Coal power plants must be designed to accommodate the particular characteristics of the coal supplied. Hence, a large number of plants must be tested over a range of coals to bring a technology to a state of commercial readiness whereby a financial backer is willing to provide financing and a technology vendor is willing to guarantee system performance under penalty of paying the costs for operation of underperforming units.

Traditional pulverized coal plants have achieved demonstrated technology status. New designs such as ultra-supercritical systems or oxygen fired (oxyfuel) systems have not achieved that level of performance attainment given their relatively new introduction as a next-generation technology. Some of EPA's criteria in the NSPS proposal are based on only a FOAK system rather than a NOAK system. Experience has shown that FOAK systems are not commercially available and additional iterations on the technology are required to achieve commercial status.

Technology Integration

Technology learning curve theory also includes the proposition that some plants may have components of a technology that can be considered as Nth of a kind, but have critical components that are new and first of a kind. Hence, a pulverized coal technology plant that uses a new technology for carbon capture, such as a membrane, could be considered as a FOAK kind of a plant for the following reason. Control and operational problems usually have to be overcome due to the difficulties of integrating the new component with an older component that was not originally designed to be a good interface with advanced technology systems.

Integrating CCS with a power generation plant introduces complexities. The full system must be designed to handle contingencies that may occur. What if access to the carbon storage reservoir becomes unavailable - what happens to the CO2 captured? Alternatively, if the plant goes off line and the reservoir performance is based on continuous injection of CO2 to avoid damage to the long term performance of the reservoir, where does the plant or reservoir operator get the CO2 needed?

CO2 injection studies into geologic reservoirs have only been carried out at scales of tens of thousands of tons of CO2 per site. Larger scale studies are underway. For a full scale operating plant, a million tons of CO2 per year may be generated and would need to be injected to handle the plant's output. We need to validate geologic storage at this scale to prove out an integrated system with a CO2 capture plant. FutureGen, which is scheduled to be on line in 2017, will integrate the operation of the Meredosia plant with the storage reservoir operations. Integration of all components will be a challenge. This experiment will be a FOAK kind of plant in the context of the present discussion. Since this plant is still not in operation, we have not yet achieved a FOAK status with regard to developing a lessons learned notebook on demonstrating the technology.

Status of Carbon Capture Technologies

Many of the currently discussed post-combustion carbon capture technologies are based on the use of amines or chilled ammonia (recent technology developed by Alstom). The amine technology was originally developed for the chemical industry. In a chemicals plant, it is often necessary to remove CO2 from the process stream. Amine systems have high operating costs. Energy is required to disassociate the captured CO2 from the amine in order to use it again in the process stream. Chemical plants producing high value products can afford the extra expense since costs are recovered in the price of the product.

The price of the electricity is one of the lowest "value-added" components of a multi-product plant – i.e, for a polygeneration plant. Here fertilizer could be made, the captured CO2 sold for enhanced oil recovery (EOR) and process steam sold for district heating. Electricity is a smaller component of the overall outputs of the plant. The Summit and HECA plants referenced in the EPA proposal are plants of this type.

The cost of operating an amine technology for carbon capture in a stand-alone power plant is relatively more than in a chemicals plant. In a plant dedicated solely to generating electricity, the cost of using the traditional amine technology is generally summarized as:

- 45-70% increase in the cost of electricity
- 35-110% increase in capital costs
- 15-21% decrease in the plant's electricity output compared to operations before carbon capture equipment was added

While it has been demonstrated that carbon capture using amines will work technologically, this type of technology is not cost competitive for a stand-alone power generation plant as compared to a chemical refinery or a polygeneration plant. Using newer advanced technologies such as membranes or ionic liquids, or revised power cycles that minimize the steps required to separate and capture CO2 are ways to reduce costs. However, these are newer technologies that have not been demonstrated at commercial scales.

Legal and Social Issues

The large number of legal and social issues associated with developing a carbon sequestration site can delay construction and must be factored into the assessment of a technology's readiness for deployment. Data from many sources show that the cost of electricity from new natural gas plants would be low compared to new coal fired plants. Around 22% of the total cost of electricity for a natural gas combined-cycle plant is the capital cost, whereas capital costs could be as much as 50% of the total cost of electricity for a coal IGCC plant. Given the large fraction of a coal plant's cost that is tied up in debt service for financing and the long operating time over which payback may occur (typically 30-40 yeas), it is important that project construction occur on a timely basis. Otherwise, the increased cost of capital over the delay period would raise the cost of electricity even higher for the coal plant.

Practice has shown, however, that the following factors often add to cost increases that affect financing, technology development, and timeliness for the construction of coal plants:

- Regulatory Issues - permitting, treatment of CO2, ...

- Infrastructure Development – pipeline construction and permitting, ...
- Human Capital – need for developing a new workforce skilled in building and managing the equipment inside the plant boundary and handling the transport and storage of CO2 in the field, ...
- Legal Framework – liability for the CO2 once it is injected, ownership of the pore space under ground, ownership of the CO2 once injected, legal hassles between states over cross-boundary transport of CO2 underground, ...
- Public Acceptance – NIMBY → NUMBY perception by the general public
- Uncertainty – uncertainty about future legislation on CO2 emissions, ...

Carbon storage in geologic reservoirs must also overcome the concerns about injecting fluid into a space that is already crowded as compared to EOR injections. Using CO2 injection for enhanced oil recovery has been ongoing for a long time. In EOR, the injection of CO2 can be likened to re-pressurizing the reservoir to an original condition and thereby counterbalances the subsidence that could occur from removing the oil. For geologic storage in saline aquifers, the injection amounts to over-pressurizing the formation, promoting migration of fluids to other areas. This result generates more concerns than for EOR processes. These factors lead to delays in permitting and construction, and hence must be considered as a part of the cost and technical readiness of a technology. These issues have not been adequately resolved to attract power plant financers to invest money in projects with CCS.

Demonstration Status of CCS Technologies

The following comments address the theme of the present hearing, namely, has the commercial deployment of CCS technologies been "adequately demonstrated" to meet the key criteria of EPA cited above.

Feasibility

As noted above, the feasibility of using amine solutions for capturing CO2 has long been demonstrated in the chemicals industry. While technically feasible, the cost of the amine solution process is very expensive for power generation. The use of these amine solutions over extended duty cycles in coal gas atmospheres needs further development.

System integration issues are also a concern with regard to the operation of amine towers. The process works by trickling the solution down a wall that is exposed to the CO2 gas. Most chemical plants operate with one tower where instabilities in the falling film of amine caused by the upward rush of the CO2-laden air can be managed based on operating experience. For a large scale power plant, multiple amine towers will be required. Fluid flow instabilities in one tower can affect the operation of adjacent towers due to switching air flows in reaction to the tower upsets. This situation is one example of integration studies that need to be performed on large scale demonstration units before the technology can be said to be adequately demonstrated at commercial scale.

Coal-based IGCC systems have not been demonstrated in sufficient numbers as noted above, especially in carbon capture applications. Many of the examples cited in the EPA proposal have been for polygeneration systems. Additional research and demonstration is needed for stand-alone IGCC power generation systems.

Long-term storage of CO_2 in geological reservoirs has not been demonstrated for large volumes of injected fluid on a continuous basis.

Cost

As noted above, costs associated with amine capture are high compared to costs that are expected to be realized when advanced carbon capture technologies come to fruition.

Additional costs are incurred due to the social and legal aspects of permitting a CCS power plant – storage field operation. These factors must be considered in assessing the cost of compliance with the 1,100 pounds of CO_2 per megawatt hour standard proposed by EPA.

The latest pulverized coal plant that is an indication of the state of pulverized coal technology is the Turk plant, which is estimated to operate at a rate of 1,800 pounds of CO_2 per megawatt hour. A significant cost and performance penalty will apply to reduce the emissions to 1,100 pounds per megawatt hour. Large scale operations of a coupled plant and storage system have not been operated sufficiently long to develop cost estimates of a combined operation.

The cost of using currently available carbon capture technologies is considered to be too expensive to be competitive for coal based systems.

Size of Emissions Reductions

Given the uncertainties associated with questions of feasibility and costs as noted above, it is likely that few if any coal plants will be deployed in the time frame proposed by EPA. Hence, the present proposal will not lead to significant reductions as stated by EPA.

However, if the proposal could be modified to delay the lower CO_2 emissions requirement, there may be opportunities to propose new plants based on technologies that could be developed in the near future. Therefore, emissions reductions could result from a delay in implementing the standard.

Technology Development

As above, if no new plants would be built, there is no driver for developing technology for CO_2 capture and storage. It is desirable to maintain a diverse portfolio of fuels to meet our energy needs. Programs that would encourage technology development are essential. Phasing in the standards over a longer time would provide a window for developing advanced technologies that could be demonstrated on a timely basis to achieve the goals of the EPA proposal.

Comments on Global Technology Development

The use of coal for power generation and chemicals production (liquid fuels, fertilizer, chemical products, ...) in China has passed the U. S. usages and the gap between the U. S. and China will continue to widen with respect to coal technologies.

Chinese planners have been willing to make investments in new technologies through support of fundamental and engineering scale research, and development of coal-based systems from large pilot plant operations to full scale development. These investments have been made by the government or by government-owned industries.

As a result, China has taken a leadership role in coal-to-chemicals and coal-to-liquid fuels production technologies, and is rapidly developing technologies for advanced power generation with coal systems and carbon storage. Their next Five Year plan will include a focus on government supported CCS activities, with active involvement in geological storage research and demonstrations.

Federal Support for Research and Demonstration Projects

The U. S. research and development program for coal-based technologies has made progress in developing advanced pulverized coal and gasification systems that include higher efficiency processes and carbon capture and storage applications. However, more progress needs to be made to achieve the goals proposed by EPA. A robust federal research, development and demonstration program is needed.

Advances in fundamental research in developing new materials, new control and integration technologies, and advanced cycles offer promise for higher efficiency in terms of power generation and in carbon capture and storage. Demonstration programs are more-or-less at the first of a kind status in developing ideas to the scale where their commercial viability and performance can be evaluated. In both of these areas, we need continued and strong support from Congress to ensure continued development of coal as a viable fuel for our nation.

Efficient coal technologies will ensure our energy and economic security by maintaining diversity in our portfolio of fuels. As a nation, we can show global leadership by developing and exporting technologies that address mounting concerns about carbon emissions. A risk we take by not acting in a strong leadership manner is that we will be buying our technology from other nations who are more aggressive in developing their technology base.

Closing Comments

Without the building of new plants, no technology advancement would occur to demonstrate the commercial readiness of new carbon capture and storage plants. Investments in a strong research, development and demonstration program, coupled with a delayed phase-in of the standards proposed by EPA would provide improved opportunities for technologists to meet the challenges proposed to us by EPA to improve our environment and economic competitiveness through advanced coal technologies. I recommend your consideration for both of these approaches.

Richard Bajura, Director
WVU National Research Center for Coal and Energy

For the past 28 years, Richard Bajura served in various roles facilitating, leading, and managing energy and environment programs in research and technical outreach at West Virginia University. During this time, he led seven major interdisciplinary - inter-institutional research programs and multiple WVU campus-wide interdisciplinary programs addressing a wide range of energy applications from resource extraction to alternative fuels. He is skilled at coordinating and managing research programs involving interdisciplinary groups of faculty members. As the Director of the NRCCE, he oversees a research enterprise with total annual budget averaging approximately $10 million. As an administrator, he has been instrumental in facilitating over $50 million in support for research faculty members at WVU. The NRCCE has developed financial and administrative management expertise to coordinate the efforts of faculty researchers working on joint programs.

In his earlier career as an active faculty member and researcher, Bajura's research interests included fluid dynamics and energy processes. His professional service included leadership in the Fluids Engineering Division of ASME where he also served as Vice President for the Basic Engineering Technical Group, representing one-sixth of the ASME membership and over 40% the Society's technical programs. He is currently active on the ASME Energy Committee, and is a member of the National Coal Council, the Coal Utilization Research Council (CURC), the Pittsburgh Coal Conference Advisory Board, and the Washington Coal Club Board of Directors. He is the Group Leader for the fuels program on the CURC Technical Committee for developing a technology road map for coal R & D programs. He serves as a technical program coordinator for WVU programs under the US-China Clean Energy Research Center.

January 2013

Chairman STEWART. Thank you, Dr. Bajura.

Our third witness is Mr. Kurt Waltzer, Managing Director at the Clean Air Task Force. In this role, he provides oversight and support of organizational management as well as ongoing development and implementation of organizational strategy. Mr. Waltzer has led the development of incentive policies for carbon capture that have been included in Federal legislative proposals and helped lead the NGO support for several carbon capture projects. Mr. Waltzer.

TESTIMONY OF MR. KURT WALTZER, MANAGING DIRECTOR, THE CLEAN AIR TASK FORCE

Mr. WALTZER. Chairman Stewart, Chairman Lummis and Ranking Members Swalwell and Bonamici, thank you for the opportunity to testify today. My name is Kurt Waltzer, and I am the Managing Director of the Clean Air Task Force, an environmental nonprofit dedicated to catalyzing the development and global deployment of low-carbon energy technologies.

First, let me explain why we believe CCS is needed. The world's power sector annual emissions are expected to double from 12 to 24 gigatons by mid-century. By 2015, China will have added 900 gigawatts of coal plants on top of our roughly 300 gigawatts of coal plants in the United States. India and other developing countries are following suit. Without significant CCS deployment, we simply will not be able to achieve the deep reductions in CO_2 emissions that are necessary to reduce the risk of catastrophic climate change.

Returning to the question in front of the Committee, CCS is technically feasible in the context of this rule because the rule requires partial, not full CCS, and because the rule allows a plant up to eight years to meet this standard. The 40 percent capture level is well within the experience of the technology. Moreover, if a plant intends to capture CO_2 on the day it opens and can't because of unforeseen issues with, for example,, completion of a CO_2 pipeline, the air compliance flexibility provision allows the plant to meet the standard over a longer time frame. The partial capture and sequestration requirement and flexibility provisions along with the ability to store CO_2 in conjunction with enhanced oil recovery, or EOR, helps ensure the rule can be met at reasonable cost, even before any Federal subsidies are considered.

CATF undertook an analysis of the initial NSPS rule first proposed in April of 2012. As we can see by figure one on page 8 of my testimony, the cost of electricity at a new coal plant that meets the partial CCS standard with EOR and takes advantage of the regulatory flexibility provision is only 13 percent higher than that of a new coal plant without CCS. CCS has been adequately demonstrated over its 40-year history in the United States. Since the 1970s and 1980s, large industrial plants have captured and stored large amounts of CO_2 on a per-plant basis up to 7 million tons per year. This experience is migrating to power plants. Nearly all new coal plants plan to have some level of CCS installed when they open. These include projects like the 582-megawatt Kemper plant in Mississippi, the Texas Clean Energy project and the Sask Power's coal retrofit project in Canada, known as Boundary Dam.

Each of the components of CCS have had a long history of use in the United States and around the world. Over 850 megatons of CO_2 have been stored underground in Texas for EOR operations over the last 30 years. There are currently 4,000 miles of CO_2 pipeline connecting CO_2 with enhanced oil recovery projects. Pre-combustion capture technology has been commercially available since the 1950s and 1960s with over 200 plant applications across the world, and post-combustion capture has been successfully applied to natural gas and coal plants with commercial guarantees offered from several vendors.

Does CATF also support incentives for CCS? Absolutely. Many technologies such as SO_2 scrubbers that have been deployed based on emission limits have continued to receive subsidies in order to make the technology more efficient and less costly. The EPA has long recognized that such subsidies are appropriately considered in evaluating the real cost of a standard. CATF is a member of the National EOR Initiative, an unusual coalition of advocacy groups, industry and labor organizations that are coming together in support of self-financing production tax credits for CO_2 EOR sourced by power plants and industrial sources.

I should note that in addition to EOR's value in reducing cost, it also provides significant potential scale. The National Energy Technology Laboratory estimates the technical potential to sequester CO_2 through EOR in the United States is as high as 80 million barrels, or 4 million barrels a day, and require 20 gigatons of CO_2. That represents about half of the total U.S. power sector emissions for the next 30 years.

We believe that EPA's rules on sound legal and technical footing is not the end of coal. Instead, it is the beginning of CCS worldwide.

I appreciate the opportunity to testify this morning and look forward to answering your questions.

[The prepared statement of Mr. Waltzer follows:]

**BEFORE THE HOUSE SUBCOMMITTEE ON ENVIRONMENT
AND THE SUBCOMMITTEE ON ENERGY OF THE
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY**

**TECHNOLOGIES TO MEET EPA'S PROPOSED NEW SOURCE
PERFORMANCE STANDARD FOR CARBON DIOXIDE
EMISSIONS FROM ELECTRIC GENERATING UNITS**

**TESTIMONY OF KURT WALTZER
MANAGING DIRECTOR
ON BEHALF OF THE CLEAN AIR TASK FORCE
OCTOBER 29TH, 2013**

Chairman Stewart, Chairman Lummis and Ranking Members Swalwell and Bonamici, thank you for the opportunity to testify today. My name is Kurt Waltzer and I am the Managing Director of the Clean Air Task Force. The Clean Air Task Force is an environmental non-profit dedicated to catalyzing the development and global deployment of low carbon energy technologies, and other climate protective technologies, through research, public advocacy leadership, and partnerships with the private sector.

The purpose of this hearing is to explore the technological requirements of EPA's proposed New Source Performance Standard. Before addressing this topic specifically, I'd like to make some general points.

First, wide-scale deployment of CCS technology is vital to averting the worst aspects of climate change. Almost two-thirds of the roughly 30 gigatons of CO_2 emissions released from human activity can be addressed through CCS technology. That's because CCS can be applied to two key emissions sectors—power plants and large-scale industrial plants. My remarks today will focus on the power sectors, where global emissions from fossil fuel power plants total about 11.9Gt per year. If no action is taken, annual power plant emissions will nearly double (24 Gt) by 2050. In developing countries, new coal plants are being built at an astounding rate. By 2015, 900 GW of coal power plants will be in operation in China—three times the size of US fleet. The vast majority of these plants are new. The vast majority of these plants are new. It is extremely important to drive controls on these plants, in the US and abroad, because plants such as these regularly last for fifty years or more, and if such development occurs without any control, we simply will not be able to achieve the deep reductions in CO2 emissions that are necessary to reduce the risk of catastrophic climate change.

Second, wide-use of CO_2 captured from power and industrial plants is vital to driving expanded use of enhanced oil recovery (EOR) in the US that will increase US oil production and decrease dependence of foreign oil. EOR recovers oil from aging oil field by injecting CO_2 deep into oil formations. The CO_2 mixes with the oil, freeing it from tight pores in the rock, and moving it to producing wells. EOR currently accounts for about 6% of US oil production. But new estimates from DOE suggest that there is enough capacity in US oil fields to store half the CO_2 emissions from the power sector over the next 30 years. That would produce almost 80 billion barrels of oil, or about 4 million barrels a day, which is over 50% of current US oil production.

Third, despite what some in industry have said, EPA's proposed CO_2 NSPS regulations are not the end of coal, but the beginning of CCS. In examining the proposed EPA's rules, the committee should consider the flexibility in the rule's structure and implementation, and how the rule helps drive CCS technology adoption. The flexibility of the proposed rules includes these features:

- An emission limit of 1100 lbs/MWh that can be met through partial, rather than full CO_2 capture. Partial capture is less expensive to implement than full capture (90% or more) on power plants.

- The proposed rules allow up to eight years to meet the rule's emission standard. This flexibility has a profound and positive impact on new coal plants. It means that a new plant can go into operation and if delays with establishing storage sites or pipelines are encountered, the plant can continue to run.

So as the subcommittees consider the status of CCS to meet the proposed EPA standards, it's key to focus the discussion within the context of the proposed rule. The rule is based upon partial, not full capture. The rule provides ample flexibility to meet this standard. And as I will describe later, at today's low natural gas prices, it is unlikely that any form of new coal plant will be built in the next decade whether or not it has CCS controls. Taken together, EPA's proposed rule is clearly a "Best System of Emission Reduction" for new coal plants[1].

I'd like to turn now to the status of CCS technology.

Status of CCS Technology

Large, integrated CCS projects began in the United States in the 1970 and 1980s at industrial facilities[2] where CO_2 was sold for enhanced oil recovery (EOR). Some of these projects capture and store 1 million tons CO_2 per year, 5 million tons CO_2 per year, and 7 million tons of CO_2per year. From its beginning in industrial facilities, CCS has migrated to power plants where it can reduce CO_2 emissions by greater than 90%. This combined industrial and power plant experience is significant. In the US we have over 4,000 miles of existing CO_2 pipelines and 40 years worth of experience with injecting managing and ultimately geologically trapping nearly a billion tons of CO_2 due to CO_2 enhanced oil recovery.

Because the component pieces of what we call CCS systems have been in widespread and safe use, separately, for 40 years or more, they are more than adequately

---

[1] section 111(a)(1) of the Clean Air Act (CAA) directs EPA to set standards of performance that: [R]eflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. 42 U.S.C. § 7411(a)(1).

[2] These include Val Verde natural gas processing plant, Enid Fertilizer project, Shute Creek natural gas processing plant, Great Plains Synfuels plant, Century natural gas processing plant

demonstrated to form the basis for an emissions standard for power plant combustion of fossil fuels. Indeed, the component parts of CCS systems are not only "adequately demonstrated" they are commercially available.

The absence of a U.S. regulatory driver has hampered the expansion of this technology. It is hard to convince an investor to put money into controls that are not required, or to convince a utility commission to grant rate recovery for investment in pollution controls that aren't required. That is true even though the enormous potential for future carbon emissions reductions associated with CCS systems makes investment in these systems very cost-effective. We need these systems to be the norm in the future, if our country is to continue to generate electricity using coal. We are not talking about an expensive technology with only marginal benefits. Instead, simply put, CCS systems are the only currently available technology that can permit the use of coal and gas for the production of electricity, at *near zero* carbon – and conventional air pollution -- emissions levels.

The migration of CCS technology to the power sector has started, and with stronger regulatory drivers, this migration will accelerate. Key projects for coal CCS include:

- The Dakota Gasification Plant (a lignite coal to Synthetic Natural Gas plant) located in North Dakota has been using pre-combustion capture technology since 2000, capturing 90% of its emissions and shipping it to permanent EOR sequestration in oil fields in Canada. The plant converts 18,000 tpd of lignite to SNG using gasification technology, capturing 1.8 MT $CO2$/yr using Rectisol. The plant has been fully operational since 2000.

- In Kemper County Mississippi, Plant Radcliffe is a new 582 MW coal power plant currently under construction. When it opens in 2014, the plant will capture 65% of its CO2 and sequester them deep underground through EOR activity. The emissions from this plant are estimated at 550 lb/MWWh (gross).

- In Odessa Texas, the Texas Clean Energy Project (TCEP) is expected to break ground later this year. The 400 MW project will turn coal into base load power, and fertilizer, and will produce CO2 that will be sequestered deep underground through EOR activity. TCEP will capture over 90% of the CO2 it would otherwise emit. The carbon dioxide emission rate for this plant when it goes into operation in 2015 will be 228 lb/MWWh (gross).

- FutureGen 2.0 is an oxy-combustion plant that will use Babcock & Wilcox (B&W) and Air Liquide technology. The 200MW plant will capture 90% of its carbon dioxide resulting in 1 MT/yr CO2 captured, and will sequester all of that CO2 in deep saline (non oil-producing/non-EOR) geologic layers in the Mt. Simon formation. The plant is expected to come online mid-2016.

- Plant Barry, Alabama- This post-combustion capture demonstration captures a slip stream of about 150,000 tons of carbon dioxide per year which is injected in a saline formation about 16 miles from the plant.

- Boundary Dam, Saskatchewan, Canada (Sask Power)- This retrofit of capture and sequestration technology onto an existing 110 MW pulverized coal unit will capture 90% of its CO_2 (1 million tons per year) for EOR and saline permanent sequestration. Start-up of the CCS controls will begin in late 2013 and go into full operation in spring of 2014.

Clean Air Act Frame and Costs

The Clean Air Act's framework recognizes that new sources of air pollution are generally in the best position to integrate pollution controls into project designs and to invest in new pollution controls. That is why the statute takes a forward looking and technology forcing perspective on performance standards, and requires every 8 year reviews to accommodate advances in technologies that have occurred in response to the standards. This approach has been an important contributor to the fact that U.S. air quality has gotten consistently better throughout the 40 years since the statute was passed in its current form. And it remains true, for CCS technology, although the Sask Power retrofit also shows that where an existing unit can accommodate it, CCS retrofits on older plants also are possible.

As noted above the Act directs EPA to set allowable pollutant emissions rates/standards of performance that take into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements.[3]

The courts also have articulated this inquiry as ensuring that the costs imposed by the standard are not "greater than the industry could bear and survive" but instead are costs to which the industry can "adjust" in a "healthy economic fashion to the

[3] The D.C. Circuit has fleshed out this mandate through a series of cases decided across several decades. *See, e.g., Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427 (D.C. Cir. 1973); *Nat'l Lime Assoc. v. EPA*, 627 F.2d 416 (D.C. Cir. 1980); *Lignite Energy Council v. EPA*, 198 F.3d 930 (D.C. Cir. 1999). For instance, the court in *Essex* held that the standard must be based on a system of pollution control that: [H]as been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control *without becoming exorbitantly costly in an economic or environmental way.* 486 F.2d at 433 (emphasis added).

end sought by the Act as represented by the standards prescribed." *Portland Cement Assoc. v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975).

Thus, the statute requires EPA to balance the environmental and economic and energy related costs of requiring emissions rate-base performance standards. EPA is given a good deal of discretion to do this, although that discretion is not unbounded. The cost-effectiveness of any particular standard is particularly relevant to EPA's ultimate evaluation of whether the industry can bear the costs, as are questions about what the investment in new units in an industry looks like even before the standard has issued.

Here, the fact that CCS offers the opportunity for near zero emissions from coal generated electricity production, combined with the fact that the industry, as a matter of pure market economics, is now not investing in coal, are going to be significant factors. Courts have said that in situations like this, EPA's decision-making based on the future of the industry during the regulated period will be upheld. Additionally, EPA's past standards have required significant investments in controls representing, for example, 12 percent of the full investment in plant, and 5-7 percent annual operating cost increases, and in other instances 10s of billions ov dollars over a 20 year period, and have been upheld as reasonable given the pollution benefits to be achieved (and that we today benefit from). So, the relevant points in this inquiry are how much reduction in the pollution in question is available through application of the standard, and what the relevant price impacts of the standard will be where the industry is one that produces a commodity.

With this frame in mind, and to investigate the price impacts of partial CCS on a mid-western coal plant, CATF published a whitepaper in December, 2012 analyzing the potential cost of EPA's then-proposed 1000 pounds per megawatt hour standard for CO2, coupled with a longer time frame for compliance.[4] The analysis is based on cost estimates developed by NETL, but considers the flexibility mechanisms in terms of longer term compliance periods included in the initial proposed rule and as well as potential income from enhanced oil recovery. The current proposal also contains flexibilities, which are tied to the regulatory period of 8 years between review cycles for NSPS, whereas the original proposal included a 30 year averaging period for compliance, under which the CCS system needed to be operating in year 10. So, while our 2012 report is based on the 30 year

---

[4] "How Much Does CCS *Really* Cost? - An Analysis of Phased Investment in Partial CO_2 Capture and Storage for New Coal Power Plants in the United States", Clean Air Task Force, December 20, 2012. In its initial proposal, the Agency allowed for CCS phase in over a 30 year averaging period, wherein the partial capture and sequestration system did not need to be operational until year 10 of the plant's lifetime, and the emissions rate needed to be met over a 30 year annual averaging period. The current proposal also includes a longer time frame, which is tied directly to the "regulatory period" of 8 years between reviews.

averaging provision, it still requires immediate work on construction and near term operation of the CCS systems.

CATF's Modeled Cost Estimates Based on Performance Standard

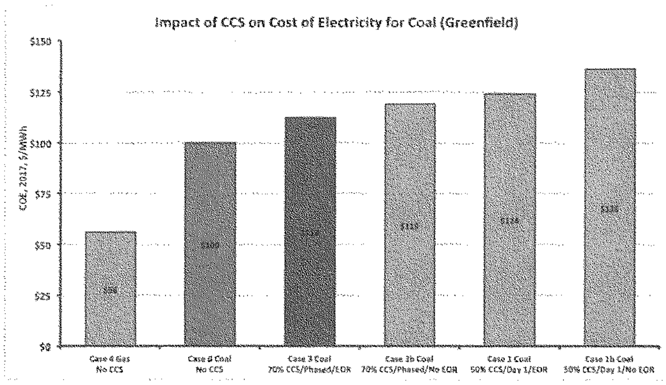
CATF published a whitepaper in December, 2012 analyzing the potential cost of EPA's first proposed NSPS rule from April, 2012[5]. The analysis is based on cost estimates developed by NETL, but considers the flexibility mechanisms included in the proposed rule as well as potential income from enhanced oil recovery. It's important to note these cost estimates included scenarios where developers delayed the installation of CCS for up to a decade, based on the proposed rule flexibility. Under the current proposed rule, developers would likely delay installation seven or eight years at most. Thus while the cost numbers will directionally stay the same, they may be somewhat higher than is outlined below. CATF will update this analysis based on the most recent proposal in the future.

The results are summarized in Figure 1 below. We found that the 2017 COE for a new natural gas combined cycle plant would be $56/MWh (Case 4), while that for a new supercritical coal power plant without CCS would be $100 per MWh (Case 0), and that for a new supercritical coal power plant with enough CCS to meet EPA's Day 1 standard would be $124 per MWh (Case 1, including revenue from sales of CO_2 for EOR). $124 per MWh represents roughly a 24% premium on the price of power the facility owner must charge in order to comply with the proposed Day 1 standard by using CCS, if it is assumed to get full rate recovery in the investment in the technology. If, however, the investment in CCS is delayed by 10 years, and the appropriate anticipatory work is done, a new supercritical coal power plant with CCS might be constructed which meets EPA's Phased standard for only $113 per MWh, representing only a 13% power price premium over the uncontrolled coal case (again after accounting for revenue associated with selling the CO2 for EOR sequestration).

For Case 1 (50% CCS from Day 1), without EOR
For Case 1 (50% CCS from Day 1) without EOR revenue the COE premium is 36% (versus 24% with EOR revenue). For Case 3 (70% CCS, Phased approach) without EOR revenue the COE premium rises is 19% (versus 13% with EOR revenue). These cases are labeled Case 1b and Case 3b, respectively in Table 2. Relative power costs for our primary cases are indicated in Figure 1 below.

[5] "How Much Does CCS *Really* Cost? - An Analysis of Phased Investment in Partial CO2 Capture and Storage for New Coal Power Plants in the United States", Clean Air Task Force, December 20, 2012

Figure 1



Cost Relationship to NSPS

The Clean Air Act's framework recognizes that new sources of air pollution are generally in the best position to integrate pollution controls into project designs and to invest in new pollution controls. That is why the statute takes a forward looking and technology forcing perspective on performance standards, and requires every 8 year reviews to accommodate advances in technologies that have occurred in response to the standards. This approach has been an important contributor to the fact that U.S. air quality has gotten consistently better throughout the 40 years since the statute was passed in its current form. And it remains true, for CCS technology, although the Sask Power retrofit also shows that where an existing unit can accommodate it, CCS retrofits on older plants also are possible.

As noted above the Act directs EPA to set allowable pollutant emissions rates/standards of performance that take into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements[6].

---

[6] The D.C. Circuit has fleshed out this mandate through a series of cases decided across several decades. *See, e.g., Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427 (D.C. Cir. 1973); *Nat'l Lime Assoc. v. EPA*, 627 F.2d 416 (D.C. Cir. 1980); *Lignite Energy Council v. EPA*, 198 F.3d 930 (D.C. Cir. 1999). For instance, the court in *Essex* held that the standard must be based on a system of pollution control that: [H]as been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control *without becoming exorbitantly costly in an economic or environmental way.* 486 F.2d at 433 (emphasis added).

The D.C. Circuit has also articulated this inquiry as ensuring that the costs imposed by the standard are not "greater than the industry could bear and survive" but instead are costs to which the industry can "adjust" in a "healthy economic fashion to the end sought by the Act as represented by the standards prescribed." *Portland Cement Assoc. v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975).

Thus the statute requires EPA to balance the environmental and economic and energy related costs of requiring emissions rate-base performance standards. EPA is given a good deal of discretion to do this, although that discretion is not unbounded.

The cost-effectiveness of any particular standard is particularly relevant to EPA's ultimate evaluation of whether the industry can bear the costs, as are questions about what the investment in new units in an industry looks like even before the standard has issued. Here, the fact that CCS offers the opportunity for near zero emissions from coal generated electricity production, combined with the fact that the industry, as a matter of pure market economics, is now not investing in coal, are going to be significant factors. Courts have said that in situations like this, EPA's decision-making based on the future of the industry during the regulated period will be upheld. Additionally, EPA's past standards have required significant investments in controls representing, for example, 12 percent of the full investment in plant, and 5-7 percent annual operating cost increases, and in other instances 10s of billions ov dollars over a 20 year period, and have been upheld as reasonable given the pollution benefits to be achieved (and that we today benefit from). So, the relevant points in this inquiry are how much reduction in the pollution in question is available through application of the standard, and what the relevant price impacts of the standard will be where the industry is one that produces a commodity.

With this frame in mind, and to investigate the price impacts of partial CCS on a mid-western coal plant, CATF published a whitepaper in December, 2012 analyzing the potential cost of EPA's then-proposed 1000 pounds per megawatt hour standard for CO_2, coupled with a longer time frame for compliance.[7] The analysis is based on cost estimates developed by NETL, but considers the flexibility mechanisms in terms of longer term compliance periods included in the initial proposed rule and as well as potential income from enhanced oil recovery. The current proposal also contains flexibilities, which are tied to the regulatory period

[7] "How Much Does CCS *Really* Cost? - An Analysis of Phased Investment in Partial CO_2 Capture and Storage for New Coal Power Plants in the United States", Clean Air Task Force, December 20, 2012. In its initial proposal, the Agency allowed for CCS phase in over a 30 year averaging period, wherein the partial capture and sequestration system did not need to be operational until year 10 of the plant's lifetime, and the emissions rate needed to be met over a 30 year annual averaging period. The current proposal also includes a longer time frame, which is tied directly to the "regulatory period" of 8 years between reviews.

of 8 years between review cycles for NSPS, whereas the original proposal included a 30 year averaging period for compliance, under which the CCS system needed to be operating in year 10. So, while our 2012 report is based on the 30 year averaging provision, it still requires immediate work on construction and near term operation of the CCS systems.

Carbon Capture

CCS is demonstrated and available for use at new coal- (and gas-) fired power plants and its core processes (CO_2 capture, transportation and sequestration) have already been utilized at large scale.

Pre-combustion capture of CO_2 is the process by which CO_2 is removed from the syngas of a gasification plant so that the remainder is mostly hydrogen. A 2010 U.S. DOE database of gasification projects lists 125 individual coal gasifiers (and 2 petcoke gasifiers) at 19 commercial projects which are used to produce either ammonia, substitute natural gas (SNG), or gaseous feedstock for liquid fuels production.[8] All three of those processes (ammonia production, SNG, and liquid fuels production) entail significant amounts CO_2 capture as a part of a purification process of the industrial gas products. *The total thermal capacity of these projects exceeds 20,000 MW, and some have been operating for decades.*

As noted above, CO_2 captured at the Dakota Gasification project is transported by pipeline to Canada, where it is used for enhanced oil recovery (EOR) and sequestered (see more below). CO_2 from the Coffeyville project is currently vented, but reportedly agreements have been signed to transport the CO_2 to Oklahoma for EOR and sequestration.

Summit's TCEP coal IGCC project in Texas will also use Rectisol®, and it was the basis for the CO_2 emission limits in a May 7, 2012 Indiana Department of Environmental Management (IDEM) air quality permit for a proposed gasification plant in Rockport, Indiana that would manufacture substitute natural gas from coal.[9]

In the coal gasification to power process, the CO2 must results in elevated-hydrogen syngas, which must be burned in a combined cycle combustion turbine to produce electricity for sale. This change presents no unreasonable technical challenges to the turbine, however. By 2006 Siemens had already accumulated more than 750,000 hours of operation with elevated- hydrogen fuels in

---

[8] CATF analysis of DOE data. The DOE data is available at http://www.netl.doe.gov/technologies/coalpower/gasification/worlddatabase/index.html..

[9] *See* Permit IDEM No. T147-30464-00060, Condition D.4.9 (Available at http://permits.air.idem.in.gov/30464p.pdf).

combustion turbines,[10] and GE had accumulated over 900,000 hours.[11] Another turbine and gasification vendor, MHI, also offers an IGCC with Selexol™ to achieve 60-65 percent CCS.[12] As a result, in their evaluation of high-hydrogen combustion turbines for the HECA IGCC project with 90 percent CCS, HEI determined that "commercial guarantees for F class turbines operating on high-hydrogen fuels would be likely."[13]

Post-combustion capture is based on aqueous solutions of amines (a family of nitrogen compounds similar to ammonia) that are commonly employed in industrial processes outside the power generation industry. These systems have been applied successfully to exhaust from natural gas (including a combined cycle power plant) and coal plants.

Table 1

Vendor	**Location**	**Exhaust Stream**	CO_2 **Use**
ABB	Searles Valley,	Coal Boiler	Chemicals Industry
ABB	Warrior Run, MD	Coal Boiler	Food Industry
ABB	Shady Point, OK	Coal Boiler	Food Industry
TPRI	Shanghai, PRC	Coal Boiler	Food Industry
TPRI	Beijing, PRC	Coal Boiler	Demonstration, Food
MHI	Kedah Darul Aman, Malaysia	NG fired SR flue gas*	Urea production
MHI	Aonla, India	NG fired SR flue gas*	Urea Production
MHI	Phulpur, India	NG fired SR flue gas*	Urea Production
MHI	Kakinada, India	NG fired SR flue gas*	Urea Production
MHI	Vijaipur, India	NG fired SR flue gas*	Urea Production
MHI	Bahrain	NG fired SR flue gas*	Urea Production
MHI	Phu My, Vietnam	NG fired SR flue gas*	Urea Production
MHI	Fukuoka, Japan	NG fired SR flue gas*	General use
MHI	Abu Dhabi , UAE	NG fired SR flue gas*	Urea Production
MHI	District Ghotoki,	NG fired SR flue gas*	Urea Production

[10] HEI, *HECA Feasibility Study Report #2 – Power Block Gas Turbine Selection* (May 29, 2009) (citing Brown, P., *Siemens Gas Turbine H2 Combustion for Low Carbon IGCC*, (Oct. 2007)).
[11] Shilling, N., Testimony of Norman Shillingon Behalf of Joint Petitioners in Cause No. 43144 Before the Indiana Utility Regulatory Commission (Oct. 24, 2006).
[12] Sakamoto, K., "Commercialization of IGCC/Gasification Technology for US Market", Oct. 7, 2008.
[13] HEI, *HECA Feasibility Study Report #2 – Power Block Gas Turbine Selection* (May 29, 2009).

MHI	Kedah Darul Aman, Malaysia	NG fired SR flue gas*	Urea production
MHI	Plant Barry, AL	Coal Boiler	Demo (amine)
Fluor	Bellingham, MA, USA	Gas Turbine Exhaust	Food Industry
Fluor	Lubbock, TX, USA	Natural Gas	Enhanced Oil
Fluor	Carlsbad, NM	Natural Gas	Enhanced Oil
Fluor	Santa Domingo, DR	Light Fuel Oil	Enhanced Oil
Fluor	Barranquilla, Columbia	Natural Gas	Food Industry
Fluor	Quito, Ecuador	Light Fuel Oil	Food Industry
Fluor	Brazil	NG / Heavy Fuel Oil	Food Industry
Fluor	Rio DeJanero, Brazil	Steam Reformer	Methanol Productio
Fluor	Sao Paulo, Brazil	Gas Engine Exhaust	Food Productio
Fluor	Argentina	Steam Reformer	Urea Plant Feed
Fluor	Spain	Gas Engine Exhaust	Food Industry
Fluor	Barcelona, Spain	Gas Engine Exhaust	Food Industry
Fluor	Bithor County, Romania	Heavy Fuel Oil	Food Industry
Fluor	Cairo, Egypt	Light Fuel Oil	Food Industry
Fluor	Israel	Heavy Oil Boiler	Food Industry
Fluor	Uttar Pradesh, India	NG Reformer Furnace	Urea Plant Feed
Fluor	Sechuan Province, PRC	NG Reformer Furnace	Urea Plant Feed
Fluor	Singapore	Steam Reformer	Food Industry
Fluor	San Fernando, Philippines	Light Fuel Oil	Food Industry
Fluor	Manila, Philippines	Light Fuel Oil	Food Industry
Fluor	Osaka, Japan	LPG	Demo Plant
Fluor	Yokosuka, Japan	Coal/Heavy Fuel Oil	Demo Plant

Fluor	Botany Australia	Natural Gas	Food Industry
Fluor	Alton, Australia	Natural Gas	Food Industry
Alstom	Mountaineer, WV	Coal Boiler	Demo (ammonia
Alstom	Mongstad, Norway	NG turbine/refinery	Demo (ammonia
Aker	Mongstad, Norway	NG turbine/refinery	Demo (amine)

All of these vendors above, except perhaps for ABB, offer commercial PCC systems for coal power projects. In fact, Fluor has said "[t]he Econamine FG+ technology is ready for full scale deployment in: Gas- and Coal-fired Power plants,"[14] and recent commercial activity supports their assertion. A January 2012 front-end engineering and design (FEED) study for Tenaska Trailblazer Partners LLC for a 760 MW (gross) pulverized coal power plant with 85 to 90 percent carbon capture to be located in Texas concluded that "Tenaska and Fluor achieved the goals of the [carbon capture plant] FEED study, resulting in ... establishment of performance guarantees which, after the addition of an appropriate margin, were consistent with the expected performance in Fluor's indicative bid."[56] Regarding their post-combustion CO_2 capture, technology, MHI says "[i]t must also be reinforced that MHI is NOW ready to provide large scale, single train commercial PCC plants for natural gas fired installations (with completed basic design for a 3,000 [tons per day] plant train) and intends to leverage this experience for application to large scale CO_2 capture for coal fired flue gas streams."

CO2 Pipelines

There are presently approximately 4000 miles of CO_2 pipeline connecting naturally mined and anthropogenic sources of CO_2 with enhanced oil recovery projects.[15] In total, this system now carries approximately 50 million metric tons per year of CO_2 throughput. The Denbury "Green" pipeline, completed in 2009, extends from Jackson MS to Houston TX, collecting and delivering both naturally mined and anthropogenic CO_2.

Based on IGCC and industrial coal gasification projects that were planned in the Ohio River Valley, Denbury had proposed 320-mile long extension of the Denbury Green pipeline to southern Illinois. While the CO_2-source projects failed to

---

[14] Reddy, S., *Econamine FG Plus Technology for CO2 Capture at Coal-fired Power Plants* (August 2008).

[15] Advanced Resources International, *U.S. Oil production potential from accelerated deployment of carbon capture and storage* (2010) (Available at http://www.adv-res.com/pdf/v4ARI%20CCS-CO2-EOR%20whitepaper%20FINAL%204-2-10.pdf).

materialize (due to several factors including low gas prices and withdrawal of state support) the extension would have connected these Midwest anthropogenic sources to fields in Mississippi, Louisiana, and Texas. Advanced Resources Inc. has estimated that three 800 mile-long pipelines could result in the storage of 30 years of Ohio River Valley EGU coal plant CO_2.[16]

There are half a million miles of natural gas and hazardous liquids pipelines rights-of-way, of which some routes might also provide rights-of-way for the build-out of CO_2 pipeline network. Elliott and Celia (2012)[17] have analyzed the storage resources in the proximity of the largest U.S. CO_2 sources in the U.S. – they report that large sources emitting 2.2 Gigatons of CO_2 are located within 20 miles of a saline reservoir.

Geologic Storage

Decades of experience in enhanced oil recovery (EOR), wastewater injection, and natural gas storage, combined with very large geologic CO_2 storage capacities in the U.S., provide confidence that long term CO_2 storage is both available and a best system of emissions reductions (BSER).[18] While commercial-scale deep saline CO_2 injection and storage experience is more limited, deep geologic injections and storage of wastewater, natural gas and for enhanced oil recovery (EOR) are commonplace in the U.S. CO_2 injection technology is grounded in a half- century of oil industry CO_2 management expertise. Moreover, natural gas companies routinely use deep geologic storage for natural gas reserves at over 400 sites in the U.S. injecting and storing natural gas in saline aquifers, depleted natural gas reservoirs and salt deposits. Including geologic wastewater injections, billions of tons of fluids are injected each year in the U.S.[19] Capacities for deep geological storage of CO_2 amount to hundreds, if not thousands of years, of present day CO_2 emissions rates. The U.S. Department of Energy's North American Carbon Storage Atlas (NACSA) released in 2012 estimates that there are approximately 500 years

---

[16] Kuuskraa, V., Advanced Resources International, *Challenges of implementing large-scale CO_2 enhanced oil recovery with carbon capture and storage* (2010) (Available at http://web.mit.edu/mitei/docs/reports/eor-css/kuuskraa.pdf).

[17] Elliot T.R. and Celia M.A., *Potential restrictions for CO2 sequestration sites due to shale and tight gas productioni,* 46 Environmental Science and Technology, 4223-4227 (2012).

[18] Benson, S., *Monitoring carbon dioxide sequestration in deep geological formations for inventory verification and carbon credits*, Society of Petroleum Engineers SPE paper 102833 (2006) (Available at http://www.energy.utah.gov/government/docs/forum/dec2006/spe102833.pdf).

[19] Wilson, E. *et al.*, *Regulating the ultimate sink: managing the risks of CO2 storage*, 37 Environmental Sci. & Tech 3476-3483 (2003).

of storage capacity for CO_2 emissions in North America.[20] Geologic formations that can accept CO_2 are widespread in the U.S., particularly in states that are rich in coal reserves. This means that where power plants are built close to coal resources, they will also be proximal to deep geologic storage resources. Furthermore, substantial capacity and transportation and injection infrastructure are currently available in EOR fields in the parts of the Rocky Mountains, Midwest, Southeast and parts of California. Cooperative research in the western U.S. is wisely evaluating development of storage resources near existing CO_2 pipelines.

Seismicity

An MIT report from April 2012 assessed the availability of geologic storage in the U.S., taking into account both geology and the fluid mechanics of injected CO_2, concluded that CCS is a geologically viable climate change mitigation option and that CCS can play a "major role" within the portfolio of climate change mitigation options even when taking into account pressure limitations[21]. MIT's model-based assessment of storage capacity for CO_2 captured from the power sector serves to counterbalance some of the broad, poorly supported assertions concerning pore pressure-based limitations and related seismic risk of large scale CCS made by Zobrak and Gorelick in their June 2012 piece. Such pressure limitations were also identified as a potential – but unknown – risk factor for induced seismicity in the National Academy of Science's June 2012 Report entitled "Induced Seismicity Potential in Energy Technologies". The MIT Report's analysis demonstrates that ample storage capacities are available for current and future power sector CO_2 emissions, even taking into account the purported pore pressure limitations.

Unlike Zobrak and Gorelick's commentary, which based its analysis solely on the Illinois basin, the MIT Report's analysis is based on storage supply curves for 11 sedimentary basins across the U.S., utilizing a model that accounts for CO_2 migration and trapping physics during the injection and storage process. Exh. Supp-2 at 5186. The MIT Report estimates that pressure-limited storage capacity for existing and future fossil fuel-fired power plants (including coal and natural gas) in the eleven identified basins would be adequate to stabilize CO_2 production from power generation for a century or more. This will continue to be true even if fossil fueled energy production continues to increase at current rates. Moreover, and

[20] Press Release: "Energy Department Announced New Mapping Initiative to Advance North American Carbon Storage Efforts" (May 1 2012) (Available at http://energy.gov/articles/energy- department-announces-new-mapping-initiative-advance-north-american-carbon-storage. The 2012 North American Carbon Storage Atlas is available at: http://www.netl.doe.gov/technologies/carbon seq/refshelf/NACSA2012.pdf.

[21] Szulczewslki, M., et al., Lifetime of Carbon Capture and Storage as a Climate-Change Technology, PROCEEDINGS OF THE NATIONAL ACADEMY OF SCIENCES Vol. 109, No. 14, at 5185-89 (April 3, 2012).

significantly, the eleven basins identified in the MIT report do not make up the entirety of potential saline storage basins in the U.S. Because the MIT Report describes only the sequestration potential capacity in those eleven U.S. basins, it underestimates U.S. CO_2 storage potential, as it does not take into account either the capacity available in offshore geologic formations or from next generation EOR projects.

Storage Regulations

A national regulatory framework now exists to support a determination that CCS is the best system of emissions reduction for any industry using that technology, and that CCS will be deployed in an environmentally protective manner. In 2010, EPA established a well class specifically designed for the geologic sequestration of CO_2 under the Federal Underground Injection Control program (UIC). *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells,* 75 Fed. Reg. 77,230 (December 10, 2010). These wells, deemed "Class VI" wells, are designed to ensure that injected CO_2 remains in a specified area and that CO_2 is properly monitored. EPA has also issued multiple guidance documents for Class VI wells that cover a variety of topics including, monitoring and testing, site characterization, area of review evaluation and corrective action, well construction, and financial responsibility.[22]

CO_2 sequestration may also concurrently occur in enhanced oil recovery (EOR) operations. UIC Class II injection permits are required for injections of CO_2 for EOR, and a process is available to obtain Class VI permit coverage for full-scale sequestration after oil production operations cease. *See* 40 C.F.R. §144.19 (2012).

Furthermore, under the U.S. Tax Code, 26 U.S.C. §45Q(d)(2), tax credits are available for those owners or operators who successfully sequester CO_2 from atmospheric release.

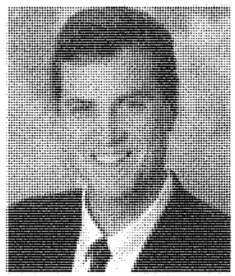
Therefore, facilities that utilize CCS must do so within a regulatory framework that ensures the CO_2 is properly accounted for, and has been isolated from atmospheric release, as well as that sequestration is occurring in a way protective of underground sources of drinking water. Where operators opt to conduct geologic sequestration of CO_2, as a part of or after conclusion of EOR operations, monitoring and reporting occurs pursuant to EPA's Greenhouse Gas Reporting rule under Subpart RR, 40 C.F.R. §98.440 *et seq.* (2012) (Geologic Sequestration of Carbon Dioxide).

The SDWA UIC Class VI and CAA Subpart RR rules, taken together, provide protection of underground sources of drinking water (USDW) and an accounting

---

[22] *See* EPA, Geologic Sequestration Guidance Documents (available at http://water.epa.gov/type/groundwater/uic/class6/gsguidedoc.cfm)

mechanism for measuring and crediting a source with the amount of CO_2 that is sequestered from atmospheric release.



Kurt Waltzer is the Managing Director for the Clean Air Task Force. He is responsible for ensuring that CATF has the capabilities it needs to carry out its vision and mission, and that these capabilities are deployed with consistent excellence. In this role, he oversees and supports organizational management and administrative activities, as well as the ongoing development and implementation of CATF's strategy and development of new efforts.

In addition to management responsibilities Kurt also spends a dedicated portion of his efforts focused on the goals and strategies of CATF' Fossil Transition Program. He bas been a long-time advocate for advanced fossil and CCUS in the environmental NGO community and has been working to promote it over the last 12 years within the US and globally. Kurt has led the development of incentive policies for CCUS that have been included in federal legislative proposals. He's also helped develop a powerful informal network of companies and experts on advanced fossil and CCUS, and helped facilitate private sector collaborations in this space.

Kurt has authored and co-authored several reports and articles and managed economic analyses on climate technology and air pollution. He's presented at and participated in several CCS/CCUS technical and policy working groups, and testified before legislative committees and regulatory agencies.

Prior to CATF, Kurt worked for the Pew Center on Global Climate Change in the area of state-based clean energy business development policy, coordinated a campaign of Midwestern ENGOs focused on the reduction of coal power plant pollution for the Izaak Walton League of America, and led the clean energy program for the Ohio Environmental Council from 1997 to 2002. He has served on the Keystone Energy Board and the Technical Advisory Committee for the Ohio Coal Development Office. He has a Masters in Business Administration from the University of Michigan and holds B.S. degrees in both Economics and Biology from the Ohio State University.

Chairman STEWART. Thank you, Mr. Waltzer.

Our final witness then is Mr. Roger Martella, Partner of Sidley Austin Environmental Practice Group. He rejoined Sidley Austin LLP after serving as General Counsel of the United States Environmental Protection Agency, concluding ten years of litigation and handling complex environmental and natural resource matters at the Department of Justice and EPA. Mr. Martella served as EPA's Chief Legal Advisor, supervising an office of 350 attorneys and staff in Washington and 10 regional offices. Mr. Martella, welcome.

TESTIMONY OF MR. ROGER MARTELLA, JR., PARTNER, ENVIRONMENTAL PRACTICE GROUP, SIDLEY AUSTIN

Mr. MARTELLA. Thank you, Chairman Stewart, Chairman Lummis, Ranking Member Bonamici and Ranking Member Swalwell for the opportunity. I am honored to be before you today with my distinguished witnesses, speakers as well.

I am going to try to very briefly discuss the intersection of how these technical issues connect with the legal framework and try not to give you an entire legal dissertation on this but just hit the high points, and I will be happy to answer any questions you have.

Very briefly, the whole reason we are here arises out of a 2007 decision called Massachusetts versus the EPA by the Supreme Court, and in that decision, the Supreme Court said that EPA had to consider greenhouse gases alongside the other air pollutants in the Clean Air Act. I was general counsel at the time when the decision came down and was tasked with working with the EPA lawyers, most of whom are still there, and other talented lawyers in the Federal Government on coming up with a full range of legal options on how to implement the mandate in the Supreme Court's decision, and one of the things we looked at very closely, which was in a 2008 document released by EPA at the time, is the New Source Performance Standard program. If you look at, you know, the limited tools EPA has under the existing Clean Air Act to address greenhouse gases for stationary sources, the New Source Performance Standard program clearly stands out. It is the most flexible of the provisions. It has a history of driving environmental results. It considers cost-benefit considerations, and of course as we have talked about today, I think as everyone is familiar with, Congress directed EPA to focus on standards that were adequately demonstrated.

So it is pretty obvious if you look at the 2008 document and work that has been done since that the highlight, the focus of attention on addressing greenhouse gases under the Clean Air Act has been on the New Source Performance Standard program when it comes to stationary sources, and so my critique is not with that as a general proposition, my critique is how EPA specifically proposed to go about this in September based on some of the technical concerns you are hearing today, and I am just going to again focus on the two words that matter the most for today's discussion, the words "adequately demonstrated."

There is a maxim the law that when Congress uses specific words, it has to mean something, that you have to actually pay attention to the specific words that Congress provides in the statute, and I recognize that that is never necessarily a black-and-white thing, that everything is a continuum and even something such as "adequately demonstrated" does not lock anyone into any one interpretation but a continuum of interpretations unless you otherwise say that we shall do something or have to do something. So the question here is, where on the continuum does EPA's approach fall, and it is my position, it is my opinion that given the technical expertise of the folks here and other people that I have spoken to, that this does fall past the end points of what is considered adequately demonstrated, the notion of requiring a technology is adequately demonstrated that is not currently in operation by EPA's own record where EPA has said there is not a single facility in commercial operation today. About 18 months ago in April 2012 in the predecessor proposal they said that this technology was not likely to be adequately demonstrated for another ten years, that even if we look back on the last 30 months of EPA's experience in granting permits for greenhouse gas emissions across the country, that it has actually rebuffed arguments by certain groups that CCS is currently adequately demonstrated. It came as a surprise to me, and I think it is past the continuum for them to say back in September that currently carbon capture and sequestration is within the realm of options they can consider in saying something is adequately demonstrated.

Now, having said that, there has been some conversation already today about what is the precedent of this and what is the effect of this, does this really affect anyone, and I think the concern as a whole is from the precedential perspective for a few reasons. First of all, the result of this rule, if this rule is finalized as it exists, and I think it is fair to say that no coal-fired power plant could be built in the United States unless they could really demonstrated carbon capture and sequestration of the magnitude EPA requires, and the experts to my side here, some of them seem to think that is not possible. So the precedent of that is basically that this rule would have the effect of preventing an entire source of energy from being used in new facilities in the future, and so I think one of the questions that comes up is, is that within the legal authority of the Clean Air Act? Can the Environmental Protection Agency—did the Congress intend for EPA to have that kind of authority to say we are going to basically phase out this type of energy going into the future. And while I recognize there is not an apples-to-apples comparison in terms of how this rule could impact existing sources or even sources in other sectors, I think it also has to be understood that there is no doubt that everyone is going to be looking to this rule as the baseline for how EPA will approach existing sources and how they might approach other sectors. I don't think they are going to start with a clean drawing board but they are going to be looking to other approaches here, even if it is not carbon capture and sequestration. So I think there is little debate that this will have precedent on how they are going to approach other issues, others types of facilities.

So thank you for that, and I look forward to answering any questions you might have.

[The prepared statement of Mr. Martella follows:]

EPA's New Source Performance Standard for Electric Generating Utilities: Dissecting the Legal Rationale for a Policy Driving Rule

Roger R. Martella, Jr.
Sidley Austin LLP

Chairman Stewart, Chairman Lummis, and Ranking Members Swalwell and Bonamici, thank you for providing me the opportunity and the honor to appear before you today.

The subject of today's hearing is critically important because it addresses both the technical and legal basis for what I believe is the most important and impactful regulation of the Obama Administration's Environmental Protection Agency: The New Source Performance Standard for Greenhouse Gases from Electric Generating Units (hereinafter, the EGU NSPS). I commend the Subcommittee for addressing this issue at a key time, and look forward to assisting your ongoing efforts.

We should be exceedingly proud that in the more than 40 years since Congress enacted the Clean Air Act, the United States simultaneously has promoted the healthiest skies and the strongest economy in the world. Congress in the Clean Air Act provided EPA specific mechanisms and tools to achieve the policy and science based goals the Agency deems necessary to fulfill its environmental mandate, but within the context of a specific and strict legal framework that the law's provisions delicately articulate. As EPA proceeds to address climate change using a law that was enacted without consideration for the unique and fundamentally distinct circumstances of greenhouse gas (GHG) emissions, these existing legal authorities are being put to new tests. While, as a general proposition, I do not take issue with EPA's authority under the New Source Performance Standard program to address GHG emissions under appropriate circumstances, the Agency's chosen path in the proposed EGU NSPS, by EPA's own admissions, surpasses the bounds of its legal authority into the realm of arbitrariness and capriciousness. Congress, in enacting the Clean Air Act, and Section 111 in particular, strictly limited the Agency's authority to control air emissions from stacks and did not authorize EPA to do what it proposes to do here and phase out an entire source of energy in the United States.

By way of background, I am both a lifelong environmentalist and a career environmental lawyer. I am very proud to have spent the majority of my career in public service, as a trial attorney in the Justice Department's Environment Division, as the General Counsel of the United States Environmental Protection Agency, and as a judicial law clerk on the Tenth Circuit Court of Appeals. In my current capacity as a private practitioner, I am privileged to work with a plethora of stakeholders including private companies and trade associations, environmental organizations, and the government, to develop creative solutions that advance environmental protection while also enabling the United States to retain economic competitiveness in a trade sensitive, global environment where very few economies provide even the faintest glimmer of our own environmental controls and public process protections.

In both my government and private careers, I am very proud of the opportunities I have had to participate in and advance environmental rule of law initiatives, working to help develop the enactment of environmental and public participation laws in growing economies. In particular, I am proud to serve as the co-chair of the International Bar Association's Climate Change Justice and Human Rights Task Force and vice-chair of the American Bar Association's Sustainable Development Task Force. Last year I was honored to have served as one of five American Bar Association delegates to the United Nations at the Rio+20 sustainable development conference in Brazil, and this year was one of five ABA delegates to the World Justice Forum on environmental and climate change justice issues.

During my tenure as EPA General Counsel, the Supreme Court decided the landmark case *Massachusetts v. EPA*. In brief, the 5-4 decision compelled EPA to consider the regulation of greenhouse gases alongside other "air pollutants" under the Clean Air Act. Shortly after the decision, President Bush and the White House tasked me to oversee the development of legal options and authority for promulgating the first-ever national GHG controls in the United States under the Clean Air Act. Working with the talented group of lawyers in EPA's Office of General Counsel and other federal agencies, I formulated a full range of legal options, along with associated pro and con considerations.

As part of this assessment, I came to appreciate certain advantages of utilizing Section 111 of the Clean Air Act—the New Source Performance Standards provision—over the various options available to address GHGs from stationary sources. When applied appropriately, NSPS can be the most effective tool for driving environmental results and emission reductions while considering the costs and benefits on those subject to such controls, the economy, energy security, and, ultimately, consumers. In fact, I advised that if EPA were compelled to regulate GHGs from utilities, NSPS should be the preferred mechanism to pursue among the existing Clean Air Act options given its flexibility, its history of realizing environmental results, and the statutory mandate to consider demonstrated technology and weigh costs and benefits of the promulgated standards.

Thus, given my history, experience, and perspective regarding Section 111, it is with regret that I offer my opinion that the NSPS EGU proposal EPA released in September steps beyond the legal bounds of the authority Congress established in the Clean Air Act.

As other witnesses have testified today, the approach EPA proposed in the EGU NSPS raises numerous technical and policy concerns for coal and pet coke fired EGUs. In setting a performance standard of 1,100 pounds of CO2/MWh, the proposed NSPS relies on two technical assumptions: (1) that the single best-performing Integrated Gasification Combined Cycle (IGCC) facility in the nation is the representative baseline for the coal and pet coke EGU industry as a whole; and (2) that carbon capture and storage is "adequately demonstrated" technology today. Relying upon these technical assumptions, EPA's proposed NSPS establishes the 1,100 pounds CO2/MWh performance standard, a standard which no commercial coal or pet coke facility in the United States if not anywhere in the world can come close to meeting. Thus, as a policy ramification, the proposed NSPS has the practical effect of being as much an energy regulation as an environmental regulation given its impact of phasing out any new coal or pet coke facilities from being built in the United States.

I defer to today's witnesses to address the technical and policy ramifications of this proposal, and instead focus on several key legal deficiencies based strictly on the record upon which EPA relies in the Rule. (The EGU NSPS raises numerous legal questions beyond the scope of this testimony, but given the focus of today's hearing I am focusing specifically on the legal ramifications of the technology questions that are at issue today.)

Let's start with the language in the Clean Air Act itself. The opening provision of Section 111 defines a "standard of performance" as

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been **adequately demonstrated**. (emphasis added)

Although the intersection of this text with EPA's proposal raises scores of legal questions and issues, for today's purposes my focus entirely is on two simple words: "adequately demonstrated." Although lawyers frequently deserve a reputation of making simple things more complicated than they need to be, I will resist that temptation today. "Adequately demonstrated" simply means what it says, and there is no need to go further to understand the fundamental and fatal flaw in EPA's proposal.

First, to base an emissions standard for all coal facilities on IGCC technology runs counter to a long standing EPA precedent that EPA cannot require facilities to "redefine the source." In other words, EPA itself long and consistently has recognized that it is not the Agency's role to dictate or switch the type of facility and energy source any given project is to utilize, but instead to identify the best system of emissions reductions for the type of source that is proposed by the project developer. IGCC units, which use combustion turbines, have significantly different designs than coal-fired boilers. Thus, EPA departed at the outset from established past precedent in utilizing a baseline that mandates the type of source facilties are required to build.

Second, and the primary focus of today's hearing, EPA clearly erred in requiring CCS under Section 111 given that, by the Agency's own admissions, the technology is not "adequately demonstrated." To be clear, EPA itself in the proposal concedes that no coal fired boiler has ever been in commercial operation with CCS or achieved the proposed limit. Simply stated, EPA in the record does not point to a single operating facility in the United States ~~or~~ in the world ~~that~~ is currently utilizing the technology that it says is "adequately demonstrated." It similarly fails to point to any commercial source that even comes close to meeting the standard that it requires as "adequately demonstrated." Importantly, EPA's prior proposed rule from April 2012 did not project CCS to be adequately demonstrated for another 10 years. This proposed rule claims that CCS is currently demonstrated, but provides no explanation of why EPA changed its outlook so dramatically in less than 18 months. Finally, beyond the record of this specific rulemaking, EPA's proposed standard also is entirely inconsistent with the Agency's last 30 months of issuing GHG permits for new facilities under the Prevention of Significant Deterioration program.

To address these legal inconsistencies, EPA provides an extensive legal justification for utilizing NSPS to develop "evolutionary" new technologies. I do not dispute that one element of many environmental standards is a technology-driving consideration, even if such technology comes with a significant cost for the regulated community, and that such standards legitimately can serve dual purposes simultaneously of driving emissions reductions while promoting the development of important new technologies. However, even when EPA is allowed to promote technology driving standards to some extent, Section 111 does not delegate carte blanche authority to simply mandate new technologies that do not satisfy the statutory mandate of "adequately demonstrated." Those two words are explicit, intentional and cannot be disregarded. It is not necessary to look any further than EPA's record in the proposed NSPS to conclude that the technologies EPA would require are not "adequately demonstrated" today, and thus violate the letter and the law of Section 111. A lengthy and complex legal justification in and of itself cannot compensate for a disregard of the plain language of the text of the statute, and EPA's legal advocacy cannot fix a conclusion that is arbitrary and capricious under the Act.

Finally, beyond the legal ramifications of this proposal on new EGUs, it is critical to anticipate and appreciate the potential precedent of this Rule on other types of facilities. First, once EPA finalizes this rule, certain groups are likely to argue that this standard "sets the floor" for so-called Best Available Control Technology (BACT) standards for facilities that are required to obtain a pre-construction permit under the Prevention of Significant Deterioration (PSD) program. Thus, this standard has the potential to cascade to other sources not directly regulated by the NSPS and where IGCC and CCS bear even less relevance.

Second, EPA has committed to regulating GHG emissions from existing EGUs no later than June, 2016. If EPA were to apply a similar legal interpretation to existing facilities of requiring retrofits of technology that is not adequately demonstrated, existing EGUs may be required to fuel switch given that Administrator Gina McCarthy has recognized that CCS is not an available retrofit technology for existing sources. Such decisions will be unpractical and uneconomic for many existing facilities, leading to shut downs, reliability concerns, and cost increases. Notably, there is a very strong legal argument that EPA has authority to avoid the regulation of existing sources under the NSPS program in the first instance and thus avoid triggering the ramifications of imposing an energy efficiency standard on the nation's existing utility fleet. This argument—that EPA is precluded under Section 111(d) from regulating existing sources that are subject to Section 112's controls for Hazardous Air Pollutants—is the straightforward reading of the text of the Clean Air Act and would enable EPA to address GHG emissions from new sources while regulating other emissions from existing sources pursuant to established programs such as the PSD permitting system and National Emissions Standards for Hazardous Air Pollutants.

Third, it is critically important to consider the impact of the EGU NSPS on other NSPS source categories. EPA has signaled—if not committed—that it plans to regulate the GHG emissions of other source categories through NSPS. However, such other source categories—which largely represent the nation's manufacturing sectors—are fundamentally distinct from EGUs. First, EPA must make separate and distinct "endangerment" determinations for each source category and decide, under Section 111, whether the emissions from a specific source category pose a "significant" contribution to endangerment. Second, unlike utilities, the processes employed by most manufacturing source categories are unique and distinct for each facility, prohibiting across the board regulation of energy use or efficiency. Third, most other source categories are trade exposed, meaning that the impact of GHG regulations on a particular source category could merely lead to such industry being located to other areas of the world that are less energy efficiency, resulting in net increases in GHG emissions globally. For these reasons, EPA should clarify that nothing it does regarding utilities shall serve as precedent for other source categories that are fundamentally distinct.

Thank you for the opportunity to share my views on this important topic. I would be happy to answer any questions.

ROGER MARTELLA is a partner in the Environmental Practice Group at Sidley Austin LLP. He rejoined Sidley Austin LLP after serving as the General Counsel of the United States Environmental Protection Agency, concluding 10 years of litigating and handling complex environmental and natural resource matters at the Department of Justice and EPA.

Mr. Martella's practice focuses on three primary areas. First, Mr. Martella advises companies on developing strategic approaches to achieve their goals in light of rapidly developing demands to address climate change, promote sustainability, and utilize clean energy. Second, Mr. Martella handles a broad range of environmental and natural resource litigation and mediation. Third, Mr. Martella advises multinational companies on compliance with environmental laws in the United States, China, the European Union, and other nations.

Mr. Martella counsels approximately 40 of the world's leading conventional and renewable energy, industrial, transportation, agricultural, forestry, and technology companies on bet-the-company environmental issues, regulatory matters, and litigation including transitioning to an era of legal controls addressing greenhouse gas emissions, increasingly stringent pollutant controls, alternative and clean energy, hydraulic fracturing, and sustainability both in the United States and abroad.

The 2013 edition of The International Who's Who of Business Lawyers lists Mr. Martella as one of the ten leading environmental lawyers in the world. The 2013 edition of Chambers includes Mr. Martella among its top-tier Washington, DC's environmental and national Climate Change lawyers and Chambers Global recognizes Mr. Martella as one of the top Climate Change lawyers globally.

Mr. Martella graduated from Vanderbilt Law School, where he was Editor in Chief of the Vanderbilt Law Review, and Cornell University, where he studied environmental science. Following law school, he clerked for the Hon. David M. Ebel of the Tenth Circuit Court of Appeals.

Chairman STEWART. Thank you, Mr. Martella.

To all of the witnesses, thank you for your testimony. I would like to remind Members that Committee rules limit the questioning to five minutes, and the chair at this point will open up the round of questions, and the chair recognizes himself for five minutes.

Mr. Martella and Mr. McConnell, I would like to come back to some comments that both of you have made. Mr. Martella, you said something I think a little more graciously than I would have in the sense of the meaning of words. I think that this all started a few years ago perhaps when we heard that famous phrase, "It depends on what the meaning of the word is is." Redefining words away from their original and their obvious intent opens up just a Pandora's Box of craziness. Who knows where it will end, and who knows what the outcome eventually is going to be, which is the main point of this hearing. This isn't about climate change. This hearing isn't about the government shutdown and effects of that. It is not even about the costs of implementing this rule. This is about—and by the way, I have enormous concerns with the costs of implementing this rule, but we are not there yet. This is about one thing and one thing only: is the EPA being honest in their claim that a certain procedure has been adequately demonstrated. And in that, it is not adequately modeled, it is not adequately hypothesized, it is not adequately wished for. Is it adequately demonstrated? And demonstrated in the real world and demonstrated in a way that could be replicated somewhere else and in fact replicated in a lot of different places because it is going to have to be in order for it to be implemented like that.

So with that, Mr. Secretary, I would like to come to you for just a minute. Let me ask first just some background. When did you leave your position at DOE?

Hon. MCCONNELL. February this past year.

Chairman STEWART. And how long did you work for the current Administration?

Hon. MCCONNELL. Two years.

Chairman STEWART. Okay. And I am sure that was a great experience for you, working for the Administration, and being here today, I suppose, you and I had a chance to have a short conversation before the hearing, and I recognize it may be somewhat uncomfortable for you in the fact that you have taken a position that is contrary to the current Administration.

Hon. MCCONNELL. Oh, I don't find it difficult at all. It is a truth that we are pursuing here, and the commercial viability and technical demonstration is all about what we were doing and continue to do with a pretty sizable Federal funding of the R&D that is going on. Now, it seems to me to be a little difficult to balance the fact that if something is already technically demonstrated and commercial available, why we would continue to fund R&D in that regard, it is a bit of a conundrum and it is puzzling to me.

Chairman STEWART. Well, I appreciate that. That is a great point.

To any of the witnesses, are any of you aware of any commercial-scale power plant in the United States that is using CCS right now, anywhere in the United States?

Mr. WALTZER. Mr. Chairman, Plant Berry at First Southern Company supplies CCS on their units, a 25-megawatt project, and they are capturing about 100, 150,000 tons per year.

Chairman STEWART. Okay, and 25-megawatt, is that a small- or a large-scale power plant?

Mr. WALTZER. It is a slipstream project from the power plant.

Chairman STEWART. So it is a very small production of power that is generated from there relatively speaking?

Mr. WALTZER. From that unit, yes.

Chairman STEWART. And that is really one of the primary concerns we have, and that is, the demonstrated scalability. You know, I was a pilot for a long time. I was the type of pilot at one point where we few test flights, and I am telling you, you can't take something and say it works here on this scale and then increase that scale by many factors and just assume that it is going to work exactly the same way; it won't, which is again one of our primary concerns here.

Dr. Bajura, you mentioned that as well, the scaling up of technology. I would be interested in your thoughts on that and your concerns about trying to apply something that is as unique and complicated as it is and just assume—and if I could, and then I will allow you to answer this. Quoting from the EPA's own findings from just several year ago, a typical power plant, "there is considerable uncertainty,"that is their word, "considerable uncertainty associated with capacities at volumes necessary." Doctor, do you have comments on that?

Dr. BAJURA. Yes. We often test technologies from test tube size in a laboratory to pilot plant sized to commercial size. The comment you made earlier about the size of plants, we have put in place 12 plants in the last six years. The average size is one gigawatt. That is 1,000 megawatts. We don't do that casually. We do it by building up, and the reason we do that is, we learn things as we go from one size to another, the integration being the very important part.

Chairman STEWART. Thank you. And again, I think the point there is stated in one fashion or another by the EPA themselves, that there is enormous concerns with the scalability on this, and with that, my time is expired.

We now turn to the Ranking Member, Ms. Bonamici.

Ms. BONAMICI. Thank you very much, Mr. Chairman, and thank you all for your testimony.

Mr. Waltzer, I wanted to talk a little bit with you about the different standards that we have been hearing about today. We have heard commercially available, technically ready, but the EPA really does look at whether the technology is adequately demonstrated, which of course is different in legal terms. Do you agree with that?

Mr. WALTZER. Absolutely. The Clean Air Act very clearly allows EPA to consider how the technology applies and other related industries, and I think in some areas there is a bit of a gray area relating to your earlier question, Mr. Chairman. So for example, Dakota Gasification is an excellent example of a project which is a very large scale, captures 2 million tons of CO_2 per year and sends it up a pipeline to Saskatchewan for EOR and sequestration. The methane that comes out of that coal gasification project is delivered in the pipeline to power plants. It is very similar to a power plant that was proposed by Tanaska, which would have simply taken that same industrial configuration and put the power plant closer to that methane, the coal-to-methane project. So from a practical perspective, it is not—the Dakota Gasification plant, I believe, clearly demonstrates that one could develop a power plant today with commercial guarantees with CCS. In fact, even though Kemper does have commercial guarantees, I think the Dakota Gasification plant clearly demonstrates that CCS at a power plant configuration is in operation today.

Ms. BONAMICI. Thank you. I am going to follow up on that a bit. If finalized, the rule would require that all new coal plants meet an emission rate between 1,050 and 1,100 points of CO_2 per megawatt-hour. So that is an approximate 40 percent reduction below uncontrolled emission levels, as I understand it.

Mr. WALTZER. That is right.

Ms. BONAMICI. But in addition, the rule allows for up to eight years to meet the standard. Can you discuss how that provision was considered in EPA's determination of feasibility and cost?

Mr. WALTZER. Sure. That provision is, from our perspective, one of the key aspects that makes this rule— the design of this rule very smart and speaks to the technical feasibility of being able to comply with the rule. With that eight-year provision, that allows a project developer to do two things. First, it allows them to have flexibility as their building their first, second, third or nth-of-a-kind project. It also allows the developer market flexibility to be able to take advantage of operating the plant in the early years without CCS and adding CCS later, which might provide financial value. In fact, it is that second component which allows, as our cost analysis shows, for a project to be able to comply with that standard and have the cost of electricity at that coal unit be 13 percent above the baseline cost of electricity for an uncontrolled coal unit.

Ms. BONAMICI. Thank you. I have another question I want to get in. So there was a project that American Electric Power was doing. Their chairman in 2011, Michael Morris, said that "As a regulated utility, it is impossible to gain regulatory approval to recover our share of the cost for validating and deploying the technology without Federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund industry share." So I wanted you to address briefly the—unless we require carbon emission limits on new coal power plants, does the technology stand as much of a chance of wider deployment, and why?

Mr. WALTZER. Well, I do agree with that, but let me address one important aspect of what you just raised. I would urge the Committee to consider that in fact this rule is good for the coal industry, and let me explain that counterintuitive view. First, the rule provides both certainty and flexibility for new coal plants regarding CO_2 emissions. If you don't have that certainty, you are not going to be able to finance new coal plants. No financing, no plants. It is basically that simple. Second, the rule does something that might have been hard to imagine 30 years ago. For the first time, new coal plants and new gas plants are going to have the same emissions profile. That is important for coal's long-term sustainability. And third, gas prices are so low that no one is building new coal, and that is true without CCS, but this rule helps catalyze technology advancements so that when fuel prices are more advantageous, coal is even better positioned within the market.

Ms. BONAMICI. Thank you, and I see my time is expired. Thank you, Mr. Chairman.

Chairman STEWART. Yes, Ms. Bonamici. And Mr. Waltzer, you almost by yourself require that we come back to a second round of questioning because I can't wait to engage you with your comments there about this is good for the coal industry.

With that, then we turn to the chairwoman of the Subcommittee on Energy, Ms. Lummis.

Chairwoman LUMMIS. Thank you, Mr. Chairman.

Secretary McConnell, does it make any sense to you that EPA is concluding that CCS is adequately demonstrated or proven when the DOE modeling assumes carbon capture technology is unproven at commercial scales?

Hon. MCCONNELL. No, it doesn't make any sense to me, and in fact, in 2010, a roadmap was put forth that with demonstration projects and the development of the fossil program would produce a commercially ready, technically deployable CCS value proposition for the marketplace by 2020, and the expectations were that the demonstration projects, the knowledge, the understanding and the learnings that would be accomplished through all of that would produce something that would be marketplace-ready by 2020. And declaring it ready now, I don't see as something that makes any sense to me, no.

Chairwoman LUMMIS. Mr. Waltzer, you mentioned this eight year period. Is that what Mr. McConnell is referencing? Should I be drawing a connection between the eight years that you mentioned and Mr. McConnell's statement about the year 2020 applicability?

Mr. WALTZER. Madam Chairman, from our perspective, just a quick reference. The original proposal actually had a ten-year delay. That was in the revision that was made eight years because that comports with the eight-year review period that relates to New Source Performance Standards. So I think that is really what is the—what is driving the eight-year review or flexibility provision within this rule.

Chairwoman LUMMIS. Okay. So they are very different. I am trying to compare apples to oranges here.

Mr. WALTZER. Right.

Chairwoman LUMMIS. That is helpful. So if the technology is ready today, why the eight years again?

Mr. WALTZER. From our perspective, we think it is valuable because we want to see projects built, and we think that kind of flexibility encourages projects. It reduces their costs. It provides them flexibility as they are developing pioneer projects. We like to say we want to avoid pioneer penalties. We want early-adopter rewards, and this, I think, is in vein with that concept.

Chairwoman LUMMIS. Okay. So it is a pioneer situation?

Mr. WALTZER. For any project that—well, there are multiple pioneer situations. For example——

Chairwoman LUMMIS. But how does the word, your use of the word "pioneer" comport with the EPA's definition of "adequately demonstrated"?

Mr. WALTZER. Well, "adequately demonstrated" as I mentioned before can be related to—or can refer to related industries. So, for example, I would consider—even though we have a fully commercial-scale gasification project at Dakota Gasification that is taking CO_2 and sending it up to Alberta—excuse me, Saskatchewan. Locadia proposed a substitute natural gas program in Indiana, which is very similar. And we were supportive of that project because even though it wasn't a power project, it would have created a pipeline from the Midwest to the Gulf Coast. I would consider them a pioneer even though that technology is commercial.

Chairwoman LUMMIS. I think you said CCS is being used today on natural gas units?

Mr. WALTZER. CCS—well, CCS has been used on natural gas units for power plants.

Chairwoman LUMMIS. Okay. So why not require this rule be applied to gas? Why is it just applied to coal?

Mr. WALTZER. We are actively supporting CCS on natural gas projects. So, for example, Summit Power has a——

Chairwoman LUMMIS. So why did the EPA just require it for coal?

Mr. WALTZER. Well, from our perspective, and I will speak from our perspective, we see—we don't see this rule as the last step; we see it as the first step. So——

Chairwoman LUMMIS. Oh, okay. That is helpful.

Mr. WALTZER. For the eight year review, we would——

Chairwoman LUMMIS. Dr. Bajura—excuse me because I have one more question. Dr. Bajura, the Interagency Task Force on CCS identified five barriers to commercial deployment of CCS. What has changed in the two years since their conclusion?

Dr. BAJURA. We have done some experiments to demonstrate storage at larger scale but we haven't done any integration to show how we could put that together with a power plant nor have we addressed the issue of long-term liability: who owns the CO_2 for 50 years, who is going to take the responsibility for certifying that the technology was correct when it was put in the ground.

Chairwoman LUMMIS. I want to thank all of our panelists. I hate to interrupt but my time is expired. Thank you all for being here.

I yield back, Mr. Chairman.

Chairman STEWART. Thank you, Madam Chairwoman.

The chair now recognizes Mr. Swalwell.

Mr. SWALWELL. Thank you, Mr. Chairman, and actually, if we could put slide number one back up there, and Mr. Waltzer, good morning, thank you to you and all of our witnesses for being here. Slide one, I held it up earlier, and it will be on the screen in a moment, depicts about 600 coal plants across the country. Are you familiar with this map and these plants, and would you agree, Mr. Waltzer, that the proposed regulations that the EPA have put out will not affect a single plant that is on that map?

Mr. WALTZER. Absolutely. Even before this rule was contemplated and even before gas prices went through the floor, there was no new coal plant that was proposed without CCS. Any new coal plant today that has been seriously proposed will meet the new coal plant standard. For existing units, this rule doesn't apply so it is not going to have any effect on them.

Mr. SWALWELL. And Mr. Waltzer, how many jobs at existing coal plants will be lost because of these regulations for future plants?

Mr. WALTZER. There will be no—I think it is simple logic that if the rule does not apply to existing units, it will not affect jobs at existing jobs, so no jobs.

Mr. SWALWELL. And Mr. McConnell, would you agree that these regulations will not affect a single job at a currently existing plant?

Hon. MCCONNELL. No, I wouldn't.

Mr. SWALWELL. Okay. Would you agree—so it is your position that if I have a job today at a coal plant that is already in existence, I am at risk of losing my job at that plant because of rules for plants that have not been built?

Hon. MCCONNELL. I think if we focus the argument strictly on one particular pollutant criteria, we could build an argument around it but it is much more complex than that. It is the future uncertainty of rulings. It is the combination of NOX, SOX, sun particulates, mercury, all of the criteria pollutants and the landscape associated with that uncertainty going forward. You see a tremendous amount of retirements going on across the country today, some 50 gigawatts of retirement.

Mr. SWALWELL. But Mr. McConnell, the 600 plants that are in existence, you agree, these rules do not directly affect those plants?

Hon. MCCONNELL. No, I don't. Again, as I go back to the interconnection of all the rulings and the future uncertainty of it, that has a multiplying effect to the future of all of those coal plants.

Mr. SWALWELL. But you can't give me an accurate number as to how many jobs are going to be lost at a current plant because of regulations for future plants, can you?

Hon. MCCONNELL. No, I am not able to provide that kind of information, no, sir. Again, it is all part of the future that you or I can't predict.

Mr. SWALWELL. And you would agree, though, that 120,000 jobs lost in 16 days during a government shutdown, that is probably greater than the amount of jobs we can say will be lost at existing plants?

Hon. MCCONNELL. I am not in a position to comment on that.

Mr. SWALWELL. I would hope, though, Mr. McConnell, that you could comment on something I think you and I may agree upon, which is that sequestration has affected our ability to make necessary investments in technology when it comes to carbon capture, use and storage technologies. Would you agree that that is not helping us learn more about what that technology could do?

Hon. MCCONNELL. What I could agree on was that when I took the job in 2010, and we projected for the next ten years that we would stay at a certain level of funding for fossil energy, to move forward and to achieve a commercially demonstrated technology by 2020, and then seeing the fossil budget cut year over year with the Administrator's requests going down while the overall Department of Energy goes up, that made it very difficult to achieve those targets, and makes it all the more difficult to understand how we can get demonstrated technology in place any earlier than 2020 certainly.

Mr. SWALWELL. Thank you, Mr. McConnell.

And Mr. Waltzer, can you just go into detail for us about the current competition between the coal and natural gas industries and whether that competition is at least a partial reason, if not the primary reason, for the retirement and lack of construction of new coal plants across the country? And then can you just let us know what would the cost of doing nothing be? Suppose we threw out these regulations and just did nothing, what would the cost to the environment and economy be?

Mr. WALTZER. So here is what I would say. Project developers today are building natural gas plants instead of coal plants, primarily because of where gas prices are. That is what is happening in the market. In terms of existing units, gas prices had gotten so low that we for the first time ever had seen coal power switch over to natural gas, which many of us thought would ever happen, but that is starting to come back. So as gas prices are going up, we are starting to see coal—existing unit coal generation come back on the system. But because of where gas prices are, we don't foresee, or at least looking at the market, the market tells us there are no plans for developing new coal projects because of where gas prices are today.

Mr. SWALWELL. Thank you, and Mr. Chairman, I yield back the balance of my time.

Chairman STEWART. Thank you, Mr. Swalwell. You know, regarding your question about existing power plants and will they be affected, I think Mr. Waltzer, you answered that question in the previous round, and that is when you said you view this as just the beginning, and I think that is many of the fears that so many of us have.

With that, to the Vice Chairman, Mr. Bridenstine.

Mr. BRIDENSTINE. Well, thank you, Mr. Chairman. I can tell you there are two coal-fired power plants in Oklahoma that are being shuttered because of EPA regulations, and I can also tell you that my constituents are facing 25 percent increases in their prices because of it, and these coal-fired power plants have, like, 30 years left in their useful lives and we are shuttering them because of these regulations.

I would like to talk to Mr. Waltzer. You mentioned early-adopter rewards. Can you talk about that for just one second?

Mr. WALTZER. Sure. We would like to see—from our perspective, we want to see CCS move forward and we would like to see a suite of policies that help both deploy the technology and drop its costs rapidly.

Mr. BRIDENSTINE. Is the Kemper project one of those projects where you have seen early-adopter rewards?

Mr. WALTZER. Well, in some respects, Kemper has received incentives, Federal incentives, to move forward. So in that context, it has gotten——

Mr. BRIDENSTINE. I would like to read you an article from the Wall Street Journal, and this is just a few weeks ago, Monday, October 14th, as a matter of fact. Mississippi Power's 186,000 customers who live in one of the poorest regions of the country are reeling at double-digit rate increases, and even Mississippi Power's parent, Atlanta-based Southern Company, has said Kemper shouldn't be used as a nationwide model. Do you agree with that?

Mr. WALTZER. I believe that the cost overruns associated with Kemper are not related to CCS. It is related to the fact that there are commercializing a new gasification technology, and so from that perspective, I believe Kemper could be a model for integrating CCS onto power systems.

Mr. BRIDENSTINE. It is interesting you should say that. They said that their cost overruns are from labor costs, steel pipe, concrete, other materials, and certainly if it wasn't for CCS, a lot of these materials wouldn't be required. Is that correct? And labor.

Mr. WALTZER. I think most of the labor costs and piping that you are referring to really is based on the fact that they are effectively developing a refinery technology, which is not what power companies are used to doing.

Mr. BRIDENSTINE. So these costs, do you know how they are affecting not just—I mean, we are talking about some of the poorest people in America being affected by this. They spend a good portion of their budgets more as a percentage of their income on their electric bills, and their electric bills are going up. Do you have sympathy or empathy for them?

Mr. WALTZER. I think that it is important to make sure that anytime we are moving technology forward, that we try to have the least amount of impact on the people who can least afford it. I think that is true in the United States and I think that is true globally. That is why we are supporting not just these performance standards but incentives at the Federal level that will help reduce the costs——

Mr. BRIDENSTINE. Real quick, I want to talk about these incentives. I am a Navy pilot and I flew in Meridian, Mississippi. I lived there for a period of time. I can tell you this, Meridian, Mississippi, just south of Kemper County, is not a wealthy part of the country. Mr. Newburn Atkinson, a gentleman, says that his Lucas Road art and jewelry gallery hasn't recovered from the recession. "I am already on a shoestring budget and this economy," the 66-year-old says, "and this may be the deciding factor in me staying open." So here we have people saying that power plants are not being shuttered; in fact, they are. We have people saying that this is actually an early-adopter rewards program, which it isn't. It is punishing people. It is punishing the poor people. It is also punishing the investors, which prevents investment in further technologies like this, and then you talk about incentives. Let us talk about incentives.

We have a chart—do we still have that chart, the Department of Energy chart about incentives for R&D for different areas? Do we have that chart? Well, while we are waiting for the chart to come up, I will share with you what is on this chart. On this chart, you have incentives for natural gas and liquid petroleum on the left. It is almost nothing. It is 64 cents per megawatt-hour. Nuclear is $3.14 per megawatt-hour. Wind, $56 per megawatt-hour. And then solar on the far right, if the chart were big enough, it would go through the roof. For wind, it's $775 per megawatt-hour, or 64 cents for gas. Now, do you think it would be a good idea to maybe shift some of those incentives from wind and solar maybe over to the gas and fossil fuel side?

Mr. WALTZER. We think we should have more incentives on the fossil fuel side, absolutely.

Mr. BRIDENSTINE. But you don't think it should be taken from—you know, it is 1,400 times more on solar energy. Do you think that that might be a good place to start?

Mr. WALTZER. We are not—here is what I can say what we support. We support, as I mentioned before, the National EOR Initiative, which is focusing on a production tax credit for CO_2-enhanced oil recovery from coal plants, gas plants, industrial sources, and what is really unique and interesting about that proposal is that because you are generating petroleum through EOR in the United States, you are also displacing foreign-oil production. That potentially could add new revenue to the U.S. Treasury, and so that is a really unique and interesting opportunity, and we think we should pursue that.

Mr. BRIDENSTINE. I am out of time, Chairman. It is your mic.

Chairman BRIDENSTINE. Thank you. I am going to return time now to Mr. Takano.

Mr. TAKANO. Thank you, Mr. Chairman.

Improving air quality and reducing greenhouse emissions is a matter that is vitally important to my constituents in Riverside County, which is located in southern California. I represent an area that has some of the worst air quality in the Nation. I remember days growing up when we weren't allowed to play outside on the playgrounds during my elementary and high school days for physical education class because the air pollution was so bad. It is because of the Clean Air Act and the work by the EPA that my region has seen a tremendous improvement in air quality. In fact, a study by the EPA shows that by 2020, the benefits of the Clean Air Act will outweigh the costs by more than 30 to one. The Clean Air Act has helped improve public health, and by 2020 it is expected to prevent 17 million lost workdays.

I appreciate hearing from our witnesses today about EPA's latest effort to limit greenhouse gas emissions under the Clean Air Act. My first question is for Mr. Waltzer. Mr. Waltzer, do you know of any other nations that are investing in CCS technology?

Mr. WALTZER. Yes, several. The United Kingdom, for example, has a competition for what they call a contract for differences to build at least two large-scale CCS projects. But probably the most interesting and notable is China. They are investing quite a bit in CCS. In fact, Huaneng Power, their largest power company, has developed their own CCS technology that they are currently doing a feasibility study with Duke Energy on one of the Gibson units in Indiana to examine how those costs of CCS in China, which they claim are fairly low, about $30 a ton, would equate in the United States.

Mr. TAKANO. And can you tell me about the overall budget for R&D for all of these all-of-the-above technologies? I mean, I understood that chart presented by my colleague from Mississippi about the distribution of R&D investment but what has been the size of that budget over the last 3 or four years and has it been increasing or decreasing?

Mr. WALTZER. Well, the overall size of the DOE budget has been increasing but I would echo what Secretary McConnell said with respect to CCS. We believe that the DOE's budget on CCS should be increased.

Mr. TAKANO. Now, you used the word "pioneering" in your answer to my colleague from Wyoming. Would you say that the strategy of the Department or the EPA is really about birthing this technology, that when we say we have an adequately demonstrated technology that really the rule is designed to birth it?

Mr. WALTZER. That has been a role that the Clean Air Act has played through several pollution control technologies, and we feel that this is a role it can play here. Just to clarify some earlier remarks I made, we do see this as the first step. We do think CCS ought to be applied on natural gas units and another opportunity to do that will be in the eight-year review as well as looking at best available control technology through individual permits after the New Source Performance Standards are finalized. So we do see this as the beginning of a process. We don't necessarily anticipate that this is going to apply to existing units through any rules that are going to be put forward but we do hope and expect and we would advocate for in the future that this technology would be applied to natural gas.

Mr. TAKANO. Now, real quickly, the Kemper plant is a coal gasification plant, but the existing coal plants, which will not be affected by this rule, are not attempting to gasify. They just strictly use the coal directly into the production of electricity. Is that correct?

Mr. WALTZER. Right. Most existing units are coal combustion units.

Mr. TAKANO. So when you talked about the increased costs at Kemper, it has to do with this newer attempt, this attempt to try to gasify the coal, but if coal plants in the future were to be straight combustion plants, you are contending that the CCS technology has been demonstrated in other areas and could work in the context of newer coal combustion plants?

Mr. WALTZER. Well, actually, yes. In fact, the Boundary Dam plant is an interesting example because, in fact, it is a retrofit, but it is using the same technology that one would use if one were building a new coal combustion plant. Similarly, NRG in the United States is currently developing a retrofit, a CCS retrofit project, that could also apply to new coal combustion units.

Mr. TAKANO. Thank you, Mr. Chairman. My time is up.

Chairman STEWART. Thank you, Mr. Takano.

Now Mr. Weber from Texas.

Mr. WEBER. Thank you, Mr. Chairman.

I think we are going to affect coal plants because as that technology gets so expensive, more plants won't be built and older plants will retire, employees will lose their jobs, so that is a given. And look, I think it was Mr. Martella that said when Congress uses words, it means something. I think that was you that said that. Is that right, Mr. Martella?

Mr. MARTELLA. Yes.

Mr. WEBER. I appreciate that. It is kind of like, if you like your doctor, you can keep your doctor. If you like your insurance, you can keep your insurance. That is kind of what you are driving at, I suspect, and I guess that oil sequestration is an okay word, or carbon sequestration is okay, but when you talk about budget sequestration, that is a bad word. So it is interesting that we see a lot of word games going on up here.

Let me ask you, are any of you familiar with the Valero plant in Port Arthur, Texas, in my district that has a carbon sequestration facility? Mr. McConnell, are you aware of that plant? Do you know the cost that was involved? Do any of you all know the cost of that plant? Let me give it to you real quickly. The Valero project cost $431 million, okay? The Department of Energy, through the stimulus, or what I call the spend-from-us, kicked in $284 million. Now, that is 66 percent of the cost of that plant. Does that sound it is capable of being duplicated? Does the government have to spend 66 percent of these facilities and these plants? Does the taxpayer get to be on the hook? Does that sound like it's capable of being duplicated? That is a rhetorical question. I will get back to you.

Ed Holland, the CEO of Southern Energy, the owner of the plant built in Kemper, Mississippi, came and spoke to the House Energy Action Team, which I am a member of, about a month ago, and here is what he—let me tell you something about Southern Energy and the plant they are building. Four billion dollars. It creates 12,000 direct and indirect jobs for construction, 1,000 direct and indirect permanent jobs. The project construction will create $75 million in state and local taxes, $30 million annually in state and local taxes. So this is a project that is extremely important and valuable to the community, and yet because of CCS, which Texas is a pioneer. One of you, I think it was you, Mr. Waltzer, or it might have been Mr. Martella that said there was already EOR underway. In other words, what you really said without knowing it was, industry was already on this. Industry was already on this without the mandate from the EPA because they will get it to work efficiently. They will make it work efficiently.

Now, when Ed Holland from Southern Energy came and spoke to the House Energy Action Team, he said CCS is not capable of being duplicated. The cost overruns were enormous, and he attributed it to CCS. Now, to their credit, the company agreed to pick up all the cost overruns, and you don't see that very often when the government mandates something. That is a rarity. But the cost overruns were attributed to CCS. He told us that in the House Energy Action Team.

Now, with what you know about Valero's costs, 66 percent picked up by the DOE, the taxpayers, and the cost overruns at Kemper, is there anyone on this panel that thinks that is really capable of being duplicated? Mr. McConnell, yes or no?

Hon. MCCONNELL. Well, I believe that is the reality of where we are today because it is not technically demonstrated and commercially available.

Mr. WEBER. Thank you. Dr. Bajura?

Dr. BAJURA. I support Secretary McConnell's comment.

Mr. WEBER. What he said. Mr. Waltzer, what they said?

Mr. WALTZER. Can you clarify?

Mr. WEBER. Do you think those two experiences demonstrate that CCS of that magnitude, on the scale that the EPA is mandating here, is capable of being duplicated?

Mr. WALTZER. I think we have seen CCS on the scale of 7 million tons per year at projects like Valero.

Mr. WEBER. Does the cost or the cost overruns not even come into the EPA's——

Mr. WALTZER. That is a purely commercial project.

Mr. WEBER. That is a purely commercial project, so when it comes, EPA is real big about attainment; we don't want noxious gases and we want most of the country to be in attainment, but they don't use the common sense of determining from a cost basis whether it is going to negatively impact industry and jobs. So would you agree with me then, Mr. Waltzer, that in that instance, EPA might themselves when it comes to common sense be in non-attainment?

Mr. Martella, do you think that is duplicable?

Mr. MARTELLA. I have to put my lawyer's hat back on, and as a lawyer, you can only look at the record and what EPA itself relies upon in making these determinations, and I go back to my original opinion. Looking simply at things that they said in this record in the past 18 months or so, I think it is their own admissions that show none of these facilities are in commercial operation to the——

Mr. WEBER. Was that admission or emission?

Mr. MARTELLA. Admission.

Mr. WEBER. Okay. Well, they are putting out some emissions all right, the EPA is. But I appreciate that opinion, and I am overrun on my time.

Chairman STEWART. Thank you.

We now have Ms. Edwards.

Ms. EDWARDS. Great. Thank you, Mr. Chairman, and to our Ranking Members as well for holding this hearing, and thanks to our witnesses.

I just have a couple of questions I want to try to get to, but I want to point out that contrary to some suggestions that have been made here today, the President's energy strategy in fact has embraced the all-of-the-above approach. He said that on many occasions, even when some of us didn't want him to say all of the above. Indeed, the rulemaking envisions, I think, a 21st century approach to fossil fuel power plants with the goal of reducing CO_2 emissions in new power plants, and I think it is important to point out the word "new." In the Recovery Act, the President committed $1.4 billion to this technology, even in the face of some of us who questioned frankly the technology, but that being as it might, the EPA has come up with a rule. It has a specific responsibility, a particular responsibility to protect our health and environment, and while industry considerations are interesting, that is not the principle responsibility of the EPA. But I happen to think that we can do both, that we can both protect the environment and we can grow jobs and we can grow an energy strategy that really embraces all of those responsibilities.

My question, first question, goes to Mr. McConnell. Something you said kind of caught my attention about the jobs question. Were you referring to a specific empirical study, university study, industry study, that points to the number of jobs that would be lost by applying standards to new power plants versus old?

Hon. MCCONNELL. I can't quote any specific study here, only that I have been exposed to a number of studies from several different sources.

Ms. EDWARDS. If you can get back to us on that and give us the particular studies, because I am a data person and I like to see the data that backs up your conclusions that jobs would be lost by applying the rule to new power plants versus old ones, and I would like to see those numbers.

And then my next question goes to Mr. Waltzer. I notice that in the industry, the oil and gas industry receives subsidies to the tune of about $7.5 billion a year. Exxon Mobil made $7.5 billion in profits in 2012, Occidental, $7.1 billion. The numbers are really huge. It seems to me that if we have an interest in doing what Mr. McConnell points out in his testimony is the need to add $100 million a year into demonstrating these projects and research and development that $100 million could come out of that $7.5 billion in subsidies that the industry receives, and so I wonder, Mr. Waltzer, if you could tell us what the additional needs you see in terms of investment in R&D and whether we have made the kind of investments we need to go into the commercial side with these coal plants and the new regulations? Because if, for example, we needed to find more money, perhaps my colleagues on the other side in this very constrained environment would be willing to remove those oil and gas subsidies so that we could put the money into demonstrating new technologies.

Mr. WALTZER. Thank you. Let me first go back to what we think is the most important objective. We think that CCS needs to be deployed globally and it needs to be affordable. So we need to move the technology forward as quickly as possible. So that brings us back to with respect to the oil industry, enhanced oil recovery as an opportunity in the United States. We could potentially have 100 gigawatts of coal plants, about a third of our coal plants, supplying CO_2 for EOR that would produce domestically produced oil if we met the technical potential for EOR in this country. We believe that a self-financing tax incentive is a very smart and effective way to move that technology forward.

What is interesting about that number, 100 gigawatts, is, if you look with the history of scrubbers and other technologies, that—you can significantly push the cost down the cost curve of that scale. It is also going to bring new technologies into the market. So in terms of research and development, two interesting technologies, just an example. One is called chemical looping, which would dramatically increase the efficiency in coal plants and dramatically reduce the cost of CCS. Another would be advanced natural gas turbines. There is at least one company that has a design that would significantly drop the cost of CCS to the point they think they can compete in the market today. So it is that sort of mix of performance standards and incentives that could pull those new technologies into the market while getting the learning curve moving forward, and that is our vision for how we think we move this technology in the United States and how we think—and the value that that is going to have globally.

Ms. EDWARDS. Thank you, and my time is expired, and so I would really love to see us move to a point where we are making investments through our tax code that are about new technologies and not just supporting an old industry that is making record profits. Thank you.

Chairman STEWART. Thank you, Ms. Edwards.

We now turn to the former full Chairman, Mr. Hall.

Mr. HALL. I thank you, Mr. Chairman, and I really do think if we are having this hearing and working together, and if I understood your purpose, it is a little bit different to the five minute dissertation that Mr. Waltzer just gave us. It is not about gigawatts or anything else that he wants to decide but I think yours is about honesty and whether or not the EPA has been honest with this Committee and honest with the people. That is the first thing I say.

I also admire Mr. McConnell, who chose truth as his purpose and his pursuit, and he is here with us today, and I want to point out that we did have hearings from the EPA during the time of my chairmanship. I think, Mr. Rohrabacher, we had them two or three times before us, and each time they testified for days and went all over the country looking for someone that would testify that fracking was ruining the drinking water, and if you are looking for honesty you can check them on that because either Mr. Rohrabacher or I asked the four who were administrative witnesses that came here, each of them testifying to the dangers of that, and the liberal press talking about the dangers of it. We asked this question in closing: can you tell us anywhere in the United States where fracking has ruined one glass of drinking water. Each of the Administration witnesses said no, all four of them. That is a record. You don't have to have somebody come in here and testify to that again. It is a record. They themselves said that. So they are not being honest with us, and I think if we get a President that will appoint a secretary of some of his administrations that will follow the law, why, we will take a good look at some of their testimony when they come before us and testify under oath, and they were reminded that they were under oath, that they were operating from the best science.

Let me get to something a little more. This hearing sheds light on the technological basis for the EPA's conclusion that CCS has been "adequately demonstrate" in its proposal that CCS should be required for new coal-burning plants. Once again, the testimony has shown that the EPA's proposed mandate reflects flawed judgment again. I might ask you, Mr. McConnell, if you would like to expand on that.

Hon. MCCONNELL. Well, just to be brief, when something is mandated and determined to be technically demonstrated, commercially available and it isn't, that makes it impossible for industry to make an investment, and by virtue of that, it will eliminate the ability to build new coal generation in this country. And maybe more importantly, as we think about a global word that the energy is going to double over the next 50 years, to get that technology to other places in the world is incredibly important because this is a global issue, not just a U.S. issue.

Mr. HALL. And I thank Chairman Lummis, who wished the EPA could be here and be here and testify again for you all to hear. I don't know how much time I have left, Mr. Chairman, or I have run out of time——

Chairman STEWART. You have got about a minute and a half.

Mr. HALL. All right, sir. Mr. McConnell, we in Texas are very proud to be leaders. Mr. Weber got onto that, and I certainly agree with his approach. I like the way he identified some of the President's promises. But the Texas Clean Energy project is a "now gen." It is integrated classification combined cycle facility that will incorporate CCS as a commercially clean coal power plant, and it is my understanding, and I may be wrong, that this project received a $450 million award in the 2010 from the Department of Energy's Clean Coal Power Initiative and received a final air quality permit from the Texas Commission on Environmental Quality in 2010. My question, I guess, once again, is to you, Mr. McConnell. Has this project begun?

Hon. MCCONNELL. No, sir. There has been no ground broken and no construction.

Mr. HALL. What are some of the challenges associated with it?

Hon. MCCONNELL. The commercial viability as well as the concerns about the demonstrated technology have made it incredibly challenging to enable commercial realization, and that has delayed the start of that plant and construction for a considerable amount of time.

Mr. HALL. And my last question. What about the status of other plants, CCS projects around the country? How far along in construction are they?

Hon. MCCONNELL. Outside of the Kemper plant that has been mentioned several times, none of them are operational or in construction, and every one of them require government subsidies at this point because of the technology readiness and commercial availability.

Mr. HALL. Once again, I thank you, and Mr. Chairman, I thank you very much for having this hearing based on seeking honesty from people who come before us to testify. Thank you. I yield back.

Chairman STEWART. Thank you, Mr. Chairman.

We now turn to Mr. Massie.

Mr. MASSIE. Thank you, Mr. Chairman.

I have just a quick question for all of the witnesses. For given kilowatt-hour or gigawatt-hour production plant, if we had a typical state-of-the-art coal-fired plant and we had the same plant but hypothetically with CCS technology, and I say hypothetically because it doesn't exist yet, the two plants producing the same amount of energy, one has CCS and one does not. For each of the witnesses, which one burns more coal? Mr. McConnell?

Hon. MCCONNELL. To produce the same amount of electricity, the one with the CCS facilities obviously because of the parasitic load.

Mr. MASSIE. Dr. Bajura?

Dr. BAJURA. I concur with the Secretary.

Mr. MASSIE. The one with CCS burns more coal?

Dr. BAJURA. Yes.

Mr. MASSIE. Mr. Waltzer?

Mr. WALTZER. Yes, I agree.

Mr. MASSIE. What do you agree with?

Mr. WALTZER. The one with CCS burns more coal.

Mr. MASSIE. And Mr. Martella?

Mr. MARTELLA. I agree.

Mr. MASSIE. So we are all in agreement that CCS technology makes a coal plant less efficient. Do all the witnesses agree with that?

Hon. MCCONNELL. Yes.

Mr. MASSIE. So I think that is important to start out there. Now, the coal companies—and let me tell you why I am motivated to ask these questions. I am from Kentucky. We are very proud of our electric generation in Kentucky. I don't have any coal mines in my district yet we have two electric arc furnaces. One produces stainless steel, one produces steel. Kentucky is a big producer of aluminum. And so this is not about coal for me per se, this is about affordable domestic energy, and this is a very serious step when we increase the cost of domestic energy.

Mr. Waltzer, how much more costly per kilowatt-hour would it be to produce electricity with CCS?

Mr. WALTZER. Our study that we submitted in testimony indicated that to comply with this rule, a new coal plant today would be about $100 per megawatt-hour, and the——

Mr. MASSIE. On a percentage basis, what would it be? How much higher to produce?

Mr. WALTZER. Well, and that was without CCS, and then the one with CCS would be 113, so it's 13 percent higher.

Mr. MASSIE. You are saying 13 percent. We had a witness just about a month ago from the DOE say it was about 50 percent higher, and so is that because it burns more coal? Is that one of the reasons?

Mr. WALTZER. So yes, and I can explain the difference between those——

Mr. MASSIE. That is all right. I just wanted to check. And how much more coal does it burn to do CCS?

Mr. WALTZER. Well, you—I would have to go back——

Mr. MASSIE. At the 40 percent level, the Administration would receive reduction, correct?

Mr. WALTZER. Depending on if it is 13 percent or 50 percent, which number you are looking at, the amount of coal you have to burn is proportional to the percentage of energy penalty that you are paying.

Mr. MASSIE. So what is the number to achieve the 40 percent reduction?

Mr. WALTZER. I would have to go back and do the math but it is—it could be—I don't know. I don't want to speculate. I would have to go back and do the math.

Mr. MASSIE. So the coal-fired generation plants in my district have done a tremendous job of decreasing sulfur emissions. Particulate, mercury, all of these things have gone down by probably a couple orders of magnitude in the last 3 decades. But it still remains a fact, does it not, that those emissions are proportional to the amount of coal burned?

Mr. WALTZER. If I understand your question correctly, is there an energy penalty on those pollution controls? Absolutely.

Mr. MASSIE. What I am saying is, when you burn more coal, do you emit more sulfur for any given plants?

Mr. WALTZER. It depends on the pollution control.

Mr. MASSIE. Let me ask that question to Mr. McConnell. For a given pollution control on a plant, if you burn more coal, does it emit more sulfur?

Hon. MCCONNELL. Yes, and it would require more handling and more treatment to process that sulfur, yes.

Mr. MASSIE. So all things being equal, the effect of implementing CCS technologies is, we are going to burn more coal, and with the same emissions controls on mercury, particulate, sulfur, NOX, we are going to be admitting more of those, given the Administration's goals?

Mr. WALTZER. That is not necessarily correct. In order to——

Mr. MASSIE. But given the same technology for all of those things, it looks to me like it would be the same. Let me also ask you—I want to move on. I have 26 seconds. Will we have to mine more coal to produce the same amount of power?

Mr. WALTZER. Yes.

Mr. MASSIE. So all of the externalities that the Administration associates with mining coal would be increased with CCS?

Mr. WALTZER. Potentially.

Mr. MASSIE. Mr. McConnell, would you like to comment on that?

Hon. MCCONNELL. I might suggest there may not be any coal mined at all because in fact, the plants will shut down and there won't be any need for coal.

Mr. MASSIE. That is my concern. We have a plant in Kentucky that is shutting down. It is going to affect 139,000 consumers of electricity in my district, so I think it is a very important point to make, that CCS is not without costs to the environment. Thank you.

Chairman STEWART. Thank you, Mr. Massey. We now turn to the gentleman from North Dakota, Mr. Cramer.

Mr. CRAMER. Thank you, Mr. Chairman, and thanks, members of the panel, for being here. It is hard almost to know where to begin. I have heard so many things this morning. But I am going to start with addressing from the North Dakota perspective this issue of whether or not New Source Performance Standards for new plants affects jobs in the existing plants, and let me assure you, it does because it is a further reflection of an attitude that has been pervasive by this Administration that tells anybody interested in fossil fuel development, we are going to punish you as much as we can, and so if you are considering building a new plant or retrofitting an old plant, the odds are against you, and it is not like it has been a hidden agenda. It has been a pretty far-out-there agenda.

I appreciate as well—I am going to use this opportunity to put a few things into the record—that Mr. Waltzer has referenced several times the Dakota gas syn fuels plant at Beulah, North Dakota. I had the opportunity as an energy regulator for ten years not only to oversee electric rates but coal mining and pipeline development, and I sited the CO_2 pipeline, much of it, that goes to Saskatchewan, and we are very proud of that project. The company that owns it, Basin Electric Power Cooperative, which is one of the largest G&T cooperatives in the country, also owns a lot of electric generation, coal combustion generation, right near Beulah, and they engage with their own money in a demonstration project, 50 percent funded by Basin Electric's members and 50 percent funded by the State of North Dakota through a tax on coal, and concluded after the feed study that it was in fact not demonstrated to be economical to do a carbon capture and sequestration project at this time, and this is in a community right on the edge of the Balkan where there is a lot of commercial application for CO_2 should it enhance oil recovery. Obviously, all the incentives are there, and yet even at that, they concluded by their study that it was in fact not feasible to do it. So I want to put into the record, Mr. Chairman, with your permission and the permission of the Committee, a number of documents referencing this feed study by Basin Electric, if that is acceptable.

And then I have a question for the panel because I think there is some premise for this. When we talk about this adequately demonstrated standard and other standards in previous Clean Air Act rules, whether it is SOX, NOX, mercury, that have applied certain standards, has there been a different or is there a benchmark or some historical lesson we can learn from previous rules and the availability of technology at that time versus what we are facing today? Is that a fair characterization for a reasonable question, Mr. McConnell, and would you be able to answer?

Hon. MCCONNELL. I think there is an interesting model to look back into the 1970s when we were all concerned about SOX, NOX, mercury and suspended particulate. The government and industry formed a successful partnership together, not at odds with each other but partnered with each other, to develop technology to reduce those criteria pollutants by 90 percent over the next 40 years while we increase the amount of coal-generated power in this country by 200 percent, and that is through the miracle of technology. And in fact, I would hope that as we look to the future, we don't get simply bounded by what we know today in terms of performance and capabilities but we are mindful of the fact that the investment for the future is really where we will be and will need to be, and I certainly hope that rulings such as this don't promote a partnership between government and industry. They promote an adversarial circumstances and tends to block out an opportunity to advance coal, not promote it.

Mr. CRAMER. Doctor, would you agree?

Dr. BAJURA. I have concerns about the scale that we are talking about. I don't think the earlier technologies were as expensive as what we are discussing here, the earlier commentary about an energy penalty of 30 percent. It costs a lot of money when you are talking about a billion dollars per plant in excessive coal use. I agree with the Secretary. We need to find a way to move forward if we are going to solve this problem, and I think government support is essential.

Mr. CRAMER. With just the few seconds I have, Mr. Waltzer, if you could just answer this. You made reference to making coal cost more, and I am going to paraphrase it. You are going to have to straighten it out for me. But you are saying that this actually benefits the coal-generated electricity by positioning it well for when gas prices rise. Could you elaborate a little bit on that, how making it cost more positions it better should gas prices rise?

Mr. WALTZER. So let me be clear. I don't know what gas prices are going to do. They may go up, they may go down, but if we take this first step to begin the process of deploying CCS technology and pushing it further down the cost curve, that will benefit coal in the future.

Mr. CRAMER. I see. I am out of time. Thank you, Mr. Chairman.

Mr. WEBER. [Presiding] Thank you, Mr. Cramer.

Mr. CRAMER. If I could, Mr. Chairman, I don't think it has been ruled on, my request to place into the record these documents from Basin Electric.

Mr. WEBER. Without objection.

Mr. CRAMER. Thank you.

[The information appears in Appendix II]

Mr. WEBER. We are going to get our act together up here Dana. We just don't know when, but the gentleman from California is recognized for five minutes.

Mr. ROHRABACHER. Thank you very much. I have been running back and forth between hearings today. As usual, they schedule two of the most important hearings that I am interested in at exactly the same time, so I am sorry if I ask something that is repetitive that had been asked earlier.

I would like to ask Mr. Martella, you had mentioned earlier in your opening statement that there was a court decision, Massachusetts, that the Supreme Court decided that the EPA has to consider or may consider CO_2. You said "has to consider." Does it say that they have to consider the CO_2 or just may?

Mr. MARTELLA. The way I interpreted the decision is, they have to consider greenhouse gases but they do not have to regulate them. The court made it clear, it was not forcing EPA to regulate greenhouse gases but it did have to consider——

Mr. ROHRABACHER. That is really an important distinction, and certainly, the Court did not mandate that they take steps to take the CO_2 out of energy production, did they, or did they say that has to be considered but they didn't say they have to do it? Is that right?

Mr. MARTELLA. You are absolutely right. It is an important distinction. The Court said the EPA can't ignore the consideration of greenhouse gases but the Court also explicitly said we are not telling EPA it must regulate greenhouse gases, just that it has to look at——

Mr. ROHRABACHER. So this is not a mandate by the Court. That is something we have to understand. What we are talking about is a policy that has been determined that this is the direction that the Executive Branch wants to go because that is what they have determined is consistent with their policy goals, not necessarily with what the Court is saying, not in contrast to the Court but not in direction mandated by the Court.

Carbon sequestration—now, I know you have had this question a number of times so I am assuming that you all agree that the CCS costs a lot more than if you didn't have to do that. Is that correct? I mean, everybody agrees to that. And let me note, our colleague, Ms. Edwards, who I deeply respect, from Maryland—I wish she was here now—talked about the EPA's responsibility for public health and environment. Well, most of the people who support this idea that we are going to do something about the CO_2 and sequestration are thinking that it is being done, it is a pollutant and they are doing this in the name of protecting health. Now, am I correct that CO_2 is not a threat to public health? Does the panel agree with that? CO_2 does not affect human beings in the process of producing electricity. Is that correct? Is there some disagreement on that? I have been through many panels on this now. You would be the first one.

Mr. WALTZER. So CO_2 is not toxic but the temperature increases associated with greenhouse gases——

Mr. ROHRABACHER. That is a different matter, okay? So CO_2 is not toxic. It is not a pollutant. But we are going to spend a lot more money on it because we have the global warming theory that basically CO_2 will affect the climate of the planet. But most of the people and the public who are looking for more. They are looking at expenses now, especially when we are in this deficit. They are actually operating under the thought that what is happening with sequestration, etc., is being done to protect their health. Well, that just isn't the case. That is not the case what we have just heard. It is based on a world climate theory, not on a personal health concept, that we have to protect people's health.

Let me just note that what we have just heard with the talk from Mr. Massey is that not only is this whole sequestration not being done in order to protect public health, but by his questioning, he made it clear, and from what your answers were, that it is actually detrimental to the public health because you are increasing the level, the amount of sulfur, mercury and other particulates, etc. that are going into the air because now you are actually——

Mr. WEBER. Will the gentleman yield?

Mr. ROHRABACHER. Yes, I certainly will.

Mr. WEBER. And I will give you some extra time. Unless the end goal is to do away with the coal industry. I yield back.

Mr. ROHRABACHER. All right. Well, I think that sometimes people are not totally upfront about what their end goals are, but we have to look at the policies they are advocating today, but I would say that what we have heard at this hearing today indicates that the Administration is rushing forward full steam ahead on this CO_2 sequestration as part of an energy production guide states in a way that will actually damage public health but is consistent with their goal of trying to have a policy that affects the climate of the entire world, which I might add, is a very questionable theory and is getting more skeptics every day on that theory.

So thank you very much, Mr. Chairman.

Mr. WEBER. Thank you.

And I thank the witnesses for being here today, and that concludes——

Ms. BONAMICI. Mr. Chairman, if I may? Thank you very much for yielding for just a moment. There were some documents that were introduced today at the hearing that we did not see before, staff was not given ahead of time, and I would like to request that all staff remind Members that it is helpful to get those ahead of time so that we can raise appropriate objections, if any. So I just wanted to put that reminder on the record, that it is important for us to see the documents ahead of time rather than for the first time at a hearing. Thank you very much.

Mr. WEBER. Thank you, Ms. Bonamici. I appreciate that.

And with that, this hearing is concluded.

[Whereupon, at 12:07 p.m., the Subcommittees were adjourned.]

Appendix I

ANSWERS TO POST-HEARING QUESTIONS

ANSWERS TO POST-HEARING QUESTIONS

Responses by The Honorable Charles McConnell

Chuck McConnell QFRs

Questions from Chairman Stewart:

1) **In 2008, the FutureGen project was nearly scuttled due to skyrocketing prices, including steel prices. Should we be concerned that the federal government is mandating use of a technology that DOE itself has had so much trouble developing at full commercial scale?**

We should be concerned that taxpayer dollars are continuing to be used to support FutureGen. The cost-creep that has occurred with this project is staggering, and none of industrial participants has shown a willingness to put any more of their own equity into its development. But the federal share of this project continues to increase. In fact, industry is pushing for more federal support. Last year when I served as the Assistant Secretary for Fossil Energy at DOE, I refused to sign a novation agreement because I did not believe that increasing the federal share up to 99 percent was appropriate.

The biggest reason why the FutureGen project does not have industry support is because it does not include any utilization of the CO2 being captured. Instead, the CO2 is stored as a waste product, which increases costs. Without enhanced oil recovery or utilization, the project economics are horrible and continue to get worse. The economics of power produced are bad and completely out of scope with the rest of the market. I do not believe the project has any chance of being completed as originally conceived. Absent political forces and given the dismal business plan, the project should have been dead several years ago.

The EPA NSPS regulations mandate a use of technology that essentially sets performance standards at the current level of natural gas combined-cycle plants. Alternate technologies, like the coal gasification in FutureGen, will be required to achieve the same standard. Several other coal gasification projects are performing well because they employ CCUS technology. The flaw for FutureGen is not wholly in the technology. A large part of the flaw is in the business development that does not take into account the low cost of traditional coal-fired plants in Illinois. One of the lessons learned from FutureGen is that we must develop workable business models, which right now require EOR and utilization of CO2, and second- and third-generation technologies to lower costs and make CCS/CCUS viable in the marketplace.

We should be concerned that with the NSPS regulations, the EPA has essentially picked winners and losers. EPA has chosen a technology and a means of power production for our country that defies the Administration's purported "All of the Above" strategy.

2) **EPA claims it can mandate CCS because the "components" have been demonstrated at facilities other than power plants. Yet, just two years ago, EPA co-authored a report that concluded, "Since the CO2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment." Which EPA is right – the one that concluded there is substantial uncertainty concerning CCS at power plants, or the one that is now mandating CCS at power plants?**

Two years ago, the EPA got it right when they made the statement about the uncertainty of commercial deployment. There is absolutely no question that there is considerable concern with mandating CCS technology – a technology that is not employed at scale anywhere in the world. To mandate its use with any level of assurance that the technology is ready for commercial deployment is ludicrous.

3) **What is the difference between regulations that incentivize carbon reductions and regulations that mandate CCS? Does the latter push coal technology beyond where companies can feasibly use it?**

There is a huge difference in approach between regulations incentivizing and mandating CCS. The latter is punitive. Mandating CCS assumes the technology is demonstrable and ready, but it is not. Mandating a standard that requires the use of a technology that is not commercially viable makes it impossible for industry to choose that source as an option. In fact, such a mandate requires industry to choose another means of producing power. It is environmental manipulation of the marketplace that takes part of our energy mix off the table, which is not healthy for energy security or an energy portfolio that is fixed on "All of the Above."

Currently, many believe that natural gas can replace coal as a cheap, clean source of power production in this country. Historically, natural gas prices have fluctuated, and they will continue to do so in the future. The power industry is not choosing to use natural gas as a source because it is cheap. They understand the expected price fluctuations. Industry is choosing natural gas because it cannot chose coal due to this type of regulation.

On the other hand, regulations that incentivize carbon reduction will drive technology choices and commercial pathways to better performance. Those regulations will push industry to achieve more creative processes and projects that will benefit the marketplace and environment, giving us more options for cheap, clean power production.

4) **EPA's cost-benefit analysis that accompanied this proposed rule stated that these standards "will result in negligible CO2 emission changes, energy impacts, [and] quantified benefits…" President Obama's executive order on regulations requires that for any regulation, the benefits must justify the cost. In light of the absence of benefits associated with this proposal, do these new standards meet the President's cost-benefit requirement?**

No.

5) **Are there any states or districts in this country in which using carbon capture and sequestration for the purpose of enhanced oil recovery is not feasible?**

Yes. There are geology issues that will either allow certain areas to be receptive to EOR or exclude certain areas from EOR use. CCS is not a solution that can be universally applied, nor should it be thought of as such. In the same manner that solar, wind, and nuclear energy sources are not a suitable fit for all 50 states, neither is EOR. However, it is an important component of a real All of the Above strategy. We need to ensure that there are suitable regional options for best choices in power production and supply of market across the country. No technologies or sources are the answer for all 50 states – including CCS. For instance, EOR will not work in the geology of the Northeastern United States. Similarly, hydro is not a viable choice for Florida. But solar might work there, when it will not work in Maine. Giving up pieces of our country's energy portfolio narrows options and forces our country into less attractive long-term cost and energy security choices.

6) **In your testimony you referenced the complicated series of interrelated EPA rules and regulations currently being enforced, promulgated or contemplated. What specifically were you referring to, and what is the risk these actions may pose to coal-fired plants?**

INSERT EPA REGULATORY TIMELINE CHART

The attached diagram illustrates my point. The mix of rules (in place, being promulgated, or contemplated for regional, national and adjacent state areas related to

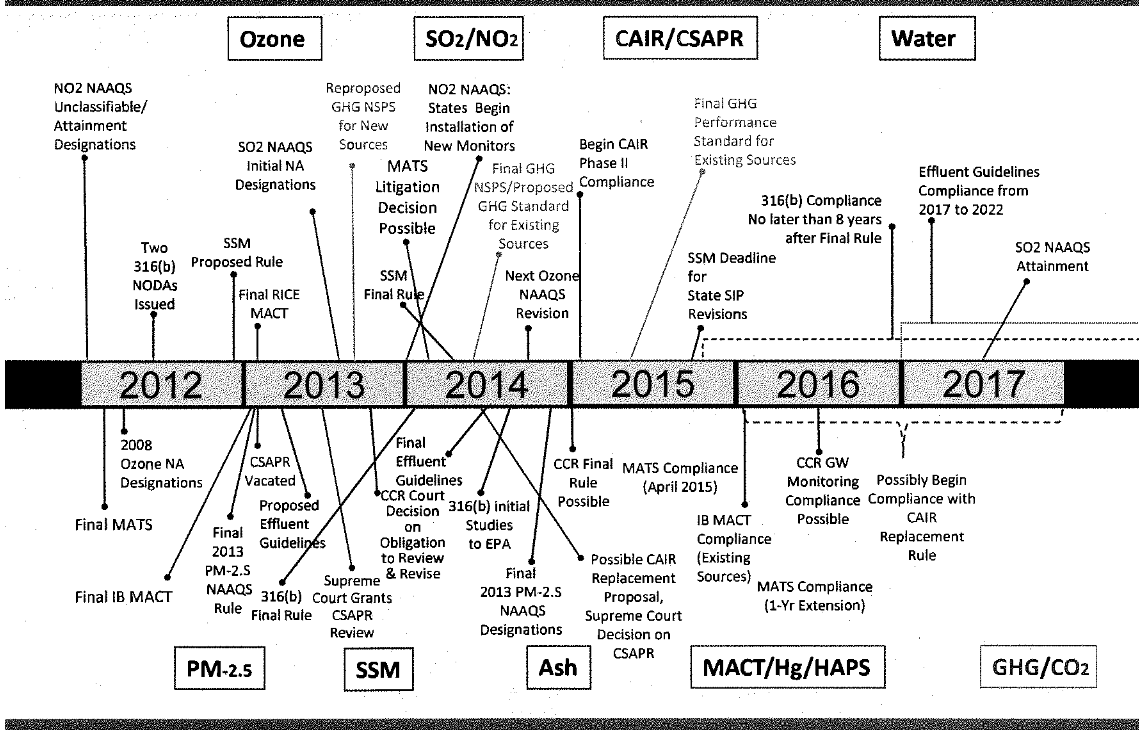
NOx, SOx, Mercury, particulate, CO2, and ash, among others) places an extreme burden for industry to plan for or calculate risk for new coal-fired power plants. This burden pushes them to pursue other technologies and will lead to an end of coal as a source for power in this country.

Questions from Representative Neugebauer:

1) **In July, I asked Mr. Chris Smith, the Acting Assistance Secretary of Fossil Energy at the Department of Energy, about the timeline for the development of CCS technology. At that time, he could not give me a set timeline for when this technology would be truly ready for commercial use. Numerous states have determined that CCS is not economically or technically feasible for power plants, and the EPA itself stopped short of saying CCS was adequately demonstrated in April of 2012. What has changed substantively in CCS development in the last year and a half?**

   The only thing that has changed substantively in the last few years is this Administration's willingness to abide by its own plan for the development and deployment of CCS technology. The Administration is cutting its internal budget for the programs outlined in the 2010 CCS R&D Roadmap. But the technical steps laid-out in the Roadmap necessary for the development of scalable CCS technology have not changed. The 2010 Roadmap called for a ten-year funding and development program with demonstration plants utilizing today's technology. The Roadmap planned for second generation technology to be deployed beginning in 2020. In 2025/2030, third generation/transformational technology would further drive cost down and make it commercially viable. To achieve the targets envisioned for technology deployment, specific research and development funding requirements must be met, but the R&D budget supporting this work has been cut by 40 percent. This underfunding threatens our ability to achieve adequately demonstrated CCS technology – which the Administration's plan, if perfectly implemented, expects would not occur before 2020. The EPA apparently failed to read the 2010 Roadmap before issuing its NSPS proposed rule, and it certainly did not take into account the underfunding of federal R&D efforts, which will only further delay our ability to achieve the 2020 goal.

EPA Regulatory Timeline



Responses by Dr. Richard Bajura

U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY
Subcommittee on Environment
Subcommittee on Energy

Hearing Questions for the Record
The Honorable Chris Stewart

EPA Power Plant Regulations: Is the Technology Ready?
Dr. Bajura

1. Dr. Bajura, help me better understand what you mean by "Scaling up technology?" What are the challenges in moving from a demonstration to full-scale commercial applications?

2. The EPA contends that use of the "component pieces" of CCS in various applications means the technology is adequately demonstrated for power plants. Can a technology system be considered adequately demonstrated and commercially available if the entire system has never been used at commercial operating scale before?

3. EPA cites three studies in the "literature" section of the new standard's "technical feasibility" discussion of CCS. Yet, EPA leaves out that one of those studies concludes that "there is truth to the often heard assertion that CCS has never been demonstrated at the scale of a large commercial power plant," another assumes carbon capture is "unproven technology" and the other – which EPA co-drafted, no less – says that carbon capture has "not been demonstrated at a scale necessary to establish confidence for power plant application." Does EPA accurately portray the science on CCS when it cherry-picks from studies in this manner?

4. In your opinion, is CCS technology today directly comparable to the technological development of scrubbers in 1980 when their use was first mandated by EPA by rule?

5. Has EPA ever adopted an emission standard that depends on ancillary activities that are not part of the normal operation of an emission source?

<u>Responses</u>

Question 1: Scale-up of Technology

In advancing a technology based on a constructed facility from its initial formulation to commercial deployment, much experimentation must be done. The first such experiments are usually done in a small laboratory apparatus to validate that the base hypothesis about the operation of the technology is sound. A laboratory reactor for testing a chemical reaction, for example, may be in a confined space with a volume of a pint of fluid. A commercial reactor may operate in a facility where the volume of the reactor space is five hundred barrels or more. The pint-sized reactor may cost $10;

the five hundred barrel reactor may cost a billion dollars. Before building the billion dollar reactor, the process is usually demonstrated in facilities of varying sizes from pints to quarts to gallons to barrels to hundreds of barrels in size. The process of proceeding from a small reactor to a commercial reactor by building test systems of larger and larger sizes is called scaling.

Testing the process in a reactor of each of the sizes discussed above is a demonstration of sorts. The larger the scale, the more other factors come into play. For example, how would the plant owner manage the waste generated daily from a large scale process compared to small amount generated over the testing of the smaller system? What kind of safety precautions need to be taken when a large vessel is exposed to high pressure requiring a large wall thickness versus a small vessel at low pressure where a thin wall tube is sufficient protection? What are the economics of the large scale system compared to competing technologies? In some cases, the performance of the full scale system may be reduced compared to the smaller versions due to the extra complexities that come into play for larger systems.

Proceeding from a small scale to a demonstration scale (usually one-third or smaller in size than the commercial version) involves taking into account factors that are non-existent or can be handled by over-building a small scale system but become large factors regarding weight, safety, or economics in a larger system. In the end, if the commercial system cannot demonstrate that it will operate economically, that it will meet performance guarantees, and will meet environmental regulations, such a system will not achieve commercial status.

Question 2: Component Testing versus System Testing

As discussed above, the larger the scale of a device, the more complex the system becomes. Many components in industrial systems were designed and tested for particular applications. These components operate effectively in the environment for which they were designed.

However, if a component is placed into another system operating with different inputs to the device and different output requirements, the device may not operate to the specifications required for the overall process. The performance of all components in a system must be effectively integrated into the overall system in order to assure an overall acceptable system performance. An effective design must have not only acceptable performance from each component, but acceptable performance of the overall system.

When a technology has not been demonstrated to perform effectively under the conditions required of a commercial system, it is difficult to find fabricators who will guarantee performance since the fabricator will pay the buyer each day over the lifetime of the unit for extra costs to the owner for performance metrics that were not met. If a fabricator will not build the device due to uncertainty in performance, it can be said that the technology is not yet developed to a commercial scale.

Question 3: Data Used by EPA in Setting Standards

I have not studied all the reports reviewed by EPA nor the general literature in the area of carbon capture for CCS applications. Often times studies appear to be similar in nature, but on inspection of all the parameters tested, there may be small differences in design or operating conditions which can change the performance of a system as discussed with respect to Question 2 above. It is necessary to carefully review the conditions under which a technology has been tested or demonstrated to be able to accurately predict its performance in a different application.

Question 4: Status of CCS Technology Compared with Scrubber Technology

Engineering studies have been performed on devices that are called First-of-a-Kind systems versus Nth-of-a Kind Systems, where N is a number much larger than one. These studies show that as one constructs newer and newer versions of a technology device, lessons are learned about the basic operation, or the construction schedule, or the material properties needed, such that it is possible to reduce costs and improve performance over time. With investments in carbon capture technology and larger scale demonstrations, the performance of carbon capture technologies currently available will improve and costs will be reduced. These effects were shown to be the case for scrubber technology development and deployment.

When technology is mandated by rule, as in the case of regulations by EPA, it is important that sufficient time be given to develop technology with the required performance and that the performance goals be set at realistic levels given the time frames required to prove out technologies developed to meet the standards promulgated by the rule. The pathway to commercialization of CCS technologies should follow a similar pathway as was noted for the development of technologies for criteria pollutants. However, the time frame for development of CCS technologies is likely to be longer given the complexity of the process in needing both capture and storage technologies to be developed at large scales. These factors are reasons why I consider the state of development of CCS technologies to be behind the corresponding state of development of technologies such as scrubbers for sulfur or for other criteria pollutants at the time similar legislation was enacted mandating control of the given effluent emitted.

Question 5: EPA Standards

I am not sufficiently familiar with EPA's procedures for setting standards to provide a response to this question.

Richard Bajura

February 18, 2014

U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY
Subcommittee on Environment
Subcommittee on Energy

Hearing Questions for the Record
The Honorable Randy Neugebauer

EPA Power Plant Regulations: Is the Technology Ready?
Dr. Bajura

1. In July, I asked Mr. Chris Smith, the Acting Assistant Secretary of Fossil Energy at the Department of Energy about the timeline for the development of CCS technology. At that time, he could not give me a set timeline for when this technology would be truly ready for commercial use. Numerous states have determined that CCS is not economically or technically feasible for power plants, and the EPA itself stopped short of saying CCS was adequately demonstrated in April of 2012. What has changed substantively in CCS development in the last year and a half?

Responses

Question 1: Changes in CCS Technology Development

I consider there to be two important technology developments that factor into the use of the term "CCS", meaning carbon capture and storage. Carbon capture occurs at the power plant. Storage is usually done in an underground reservoir. These two aspects, capture and storage, employ two different technology approaches and are coupled in that once the CO2 is captured, it must be stored. The coupling is usually considered to be a pipeline that takes the CO2 from the source to the sink.

Carbon capture technology is well developed in the chemical engineering field. In the production of chemicals, it is sometimes necessary to remove CO2 from the process stream. Hence, CO2 removal technologies were developed by the chemicals industry. While the cost of these technologies is high, the value of the product manufactured is high enough that the capture cost can be recovered in the selling price. In the case of carbon capture in a power plant, the current technologies (e.g., amines or chilled ammonia processes) that are available can remove CO2, but the cost of operating systems is high and the resulting selling price of electricity is greatly increased. Recently, DOE Office of Fossil Energy personnel testified that capture costs could be as high as $90 per ton of CO2 captured and that the cost of electricity for such plants could be almost doubled. Electricity produced using these technologies is not cost competitive with electricity produced by, say, natural gas without carbon capture. Hence, while the technology is available to capture CO2, the cost is so prohibitive that systems based on these technologies will not be used commercially. Since commercial deployment for a technology is based on its effectiveness at performing the required task and its cost competitiveness compared to other processes, many states have determined that this part of the CCS requirement is not economically feasible.

Over the past several years, new technology pathways to capture CO2 have been proposed. One way to improve capture technologies is to improve cycles. Recent studies have shown that processes such as ultra-supercritical pressure coal power systems, oxygen-fueled combustion systems, and chemical looping systems offer promise to reduce the cost of capture compared to existing technologies. Additional research is needed for these technologies to validate their effectiveness in the commercial market. Other advanced cycles are also being studied which may result in even greater performance of the capture component of fossil fuel power generation. These new technologies have emerged in the past two years as having promise and worthy of further investigation. However, development of the technologies for commercial application is complicated by the absence of federal funding to do demonstration projects and the uncertainty of future construction of coal power plants in the face of the proposed NSPS rule for new coal plants. Hence, developing a timeline for deployment is a difficult task.

Turning to the issue of storage in the parlance of CCS, it is necessary to demonstrate that carbon can be injected into underground saline reservoirs, for example, in a manner that will not be detrimental to the environment in the near term and in the long term. Such research programs have not been conducted and evaluated for applications such as would be applicable to a large (600 megawatts) power plant operating over a long period corresponding to the typical lifetime of the plant. Injecting carbon underground is not cost effective – it costs money to do and there is no apparent benefit. Some offsets in cost can be obtained by injecting CO2 into oil reservoirs for enhanced oil recovery operations. But the costs of recovered oil do not offset the operational costs of capturing the CO2 at the power plant. We need additional work to prove out the safety and performance of underground reservoirs to gain acceptance by the general public while demonstrating the effectiveness of injection schemes. Proving out schemes for injection that need to be tested over a large number of years to demonstrate permanent, safe storage is not a program that can be completed in several months. Hence, timelines for deployment of commercial storage technologies is also difficult to predict.

Our nation needs a steady, robust program of technology development both for carbon capture and storage to prove out these new technologies. By supporting a strong program of research, we can develop cost-effective technologies for both capture and storage and then be able to confidently predict times for deployment of advanced technologies. I recommend continued support for coal based research programs to ensure that coal remains in the national energy mix since it is a highly abundant energy resource.

R. Bajura

N:\HEARINGS\ENVIRONMENT\113th First Session\10.29.13 NSPS\Responses QFRs\Bajura Responses.docx

Responses by Mr. Kurt Waltzer

U.S. HOUSE **OF REPRESENTATIVES**
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY
Subcommittee on Environment
Subcommittee on Energy

Hearing Questions for the Record
The Honorable Randy Neugebauer

EPA Power Plant Regulations: Is the Technology Ready?

Mr. Waltzer

1. In July, I asked Mr. Chris Smith, the Acting Assistant Secretary of Fossil Energy at the Department of Energy about the timeline for the development of CCS technology. At that time, he could not give me a set timeline for when this technology would be truly ready for commercial use. Numerous states have determined that CCS is not economically or technically feasible for power plants and the EPA itself stopped short of saying CCS was adequately demonstrated in April of2012. What has changed substantively in CCS development in the last year and a half?

Response:

We maintain that CCS is an adequately demonstrated technology today. As noted earlier in my written testimony, this is based on a long history of the technology and its components:

• Large, integrated CCS projects began in the United States in the 1970 and 1980s at industrial facilities where C02 was sold for enhanced oil recovery (EOR). Some of these projects capture and store 1 million tons C02 per year,5 million tons C02 per year, and 7 million tons of C02 per year.[1] From its beginning in industrial facilities, CCS has migrated to power plants where it can reduce C02 emissions by greater than 90%.

• In early 2012 there were 127 U.S. C02 EOR projects with approximately 7,100 C02 injection wells and 10,500 producing wells. According to the National Petroleum Council, approximately 3 billion cubic feet per day of C02 (57 Mt/yr) of newly purchased C02 are presently injected for tertiary EOR producing 286,000 barrels of oil per day (105 million barrels per year

• Nearly 1 billion tons of C02 have been stored underground in U.S. oil fields from EOR operations over the last 40 years. In its 2013 National Assessment of Geologic Carbon Dioxide Storage Resources, the U.S. Geological Survey assessed the technically accessible geologic carbon storage resources in 36 sedimentary basins in the onshore and beneath state waters of the United States. The assessment only inventoried geologic formations below 3,000 feet with adequate porosity and permeability to accept commercial volumes of C02. The assessment estimates that there are approximately 3,000 Gt of subsurface storage

[1] These include Val Verde natural gas processing plant, Enid Fertilizer project, Shute Creek natural gas processing plant, Great Plains Synfuels plant, Century natural gas processing plant

capacity. This represents more than 500 times the 2011 annual 5.5 Gt of energy-related CO_2 emissions in the U.S. today. In addition, DOE estimates that 500 to 7,500 Gt of CO_2 could be sequestered in all U.S. offshore formations on the outer continental shelf

• There are presently approximately 4000 miles of CO_2 pipeline connecting naturally mined and anthropogenic sources of CO_2 with enhanced oil recovery projects.

• Pre-combustion capture technology has been commercially available since the 1950s and 1960s. Two of the main technology options, Selexol and Rectisol, have over 100 plant applications each across the world.

• Post combustion capture has been successfully applied to exhaust gases from both natural gas and coal plants, with commercial guarantees offered from several vendors.

An adequate demonstration of the technology is different from the issue of whether or not a technology will be used absent regulatory or statutory requirements or incentives. For example, power companies will not add sulfur dioxide scrubbers unless they are required to do so, or it makes economic sense based on the sulfur dioxide cap and trade system.

In some cases, such as the addition of CCS at Southern's Kemper plant in Mississippi, the integration of CCS in the development of a new generation project and the use of enhanced oil recovery helped move the project forward. But even in states that clearly have a vested interest in CCS technology, a lack of clear regulatory limits creates deployment barriers. For example, in 2011, the West Virginia Public Service Commission considered AEP's request for rate-payers to cover AEP's portion (50%) ofthe cost associated with the 250 MW scale CCS retrofit project - with the remaining portion covered by a grant from the Department of Energy's Clean Coal Power Initiative. Unlike Kemper, the project was not integrated into a new power project, nor did it include EOR as a storage opportunity.

Nonetheless, the Commission did not reject the project outright, nor did it find that the project was not feasible based on economics or technology status. Instead, the PSC stated:

> "We are concerned about the future of CCS and the enormous potential that it might hold for West Virginia and our natural resources."

And,

> "... as the CCS project is operating at a nominal level and is in fact sequestering some of the CO_2 from the Mountaineer Plant, we are willing to allow a proportionate share of those expenses to be included in operating expenses in this case. To be fair, as discussed above, we believe that this operating cost also needs to be shared among all AEP operating companies."[2]

Thus the WV PSC recognized the importance of CCS and on that basis offered to cover a portion of the costs requested for recovery by AEP, but in AEP's view, that was not enough to make the project viable. A lack of regulatory certainty created a barrier for the PSC agreeing to cover the full costs. As AEP stated at the time:

---

[2] Public Service Commission of West Virginia, Case No. 10-0699-E-42T, March30, 2011.

"as a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place."[3]

While lack of regulatory certainty is a current barrier to CCS technology, it is encouraging to note that two CCS power propjets (Kemper, and SaskPower's Boundry Dam project) and one large-scale industrial project (Shell's Quest project in Alberta) are slated to finish construction and come on line in the Spring of2014. That CCS activity, just in the last year and half, is an example of an application of a technology based on a long history of industrial activity. Greater regulatory certainty is important for further technology deployment. Finalizing EPA's proposed New Source Performance Standards is a crucial and necessary step towards creating this certainty.

I will be pleased to provide any additional information or clarifications that you need, if any.

[3] "American Electric Power Puts $668 Million plan on hold", Charleston Daily Mail, July 15, 2011.

Responses by Mr. Roger Martella

SIDLEY AUSTIN LLP
SIDLEY

SIDLEY AUSTIN LLP
1501 K STREET, N.W.
WASHINGTON, D.C. 20005
(202) 736 8000
(202) 736 8711 FAX

rmartella@sidley.com
(202) 736 8097

BEIJING
BRUSSELS
CHICAGO
DALLAS
FRANKFURT
GENEVA
HONG KONG
HOUSTON
LONDON

LOS ANGELES
NEW YORK
PALO ALTO
SAN FRANCISCO
SHANGHAI
SINGAPORE
SYDNEY
TOKYO
WASHINGTON, D.C.

FOUNDED 1866

January 26, 2014

Honorable Chris Stewart
Chairman, Subcommittee on Environment

Honorable Cynthia Lummis
Chairman, Subcommittee on Energy

Committee on Science, Space, and Technology
2321 Rayburn House Office Building
Washington, DC 20515-6301

Re: Re: Response to Questions for the Record, "Hearing on EPA Power Plant Regulations: Is the Technology Ready?"

Dear Chairman Stewart and Chairman Lummis:

Thank you again for the honor to appear before your subcommittee to provide my views regarding the Environmental Protection Agency's New Source Performance Standards for Electric Generating Units. As I testified, I believe EPA's proposal raises significant legal and technical issues, and I commend the Subcommittee for addressing this issue at a critical time and look forward to assisting your ongoing efforts.

My responses to your questions for the record are below.

In your opinion, is CCS technology today directly comparable to the technological development of scrubbers in 1980 when their use was first mandated by EPA by rule? Has EPA ever adopted an emission standard that depends on ancillary activities that are not part of the normal operation of an emission source?

In short, the requirement in the proposed new source performance standard mandating carbon capture and sequestration (CCS) is unprecedented from both technological and legal perspectives. In the preamble, EPA itself acknowledges that CCS has not been demonstrated or operated at any commercial facility, regardless of scale. At the same time, EPA flatly contradicts itself by concluding this technology is "adequately demonstrated" for purposes of satisfying the legal standard in Section 111(b). Simply stated, both things cannot be true. While EPA fairly points out that case law over the years has added context to the meaning of "adequately demonstrated" technology under Section 111(b), it is arbitrary and capricious to interpret either the provision or the case law in such an extreme way to require technology that has not been put to use in any demonstrated scenario (and that EPA acknowledges has never been commercially demonstrated), let alone require it on a commercial scale of the magnitude anticipated by the proposed Rule. The analogy to scrubbers is inapposite. At the time EPA mandated scrubbers, the technology had been proven and was in commercial use at the scale required by the rule, even if not widely deployed. The situation with CCS stands in sharp contrast to that scenario, with EPA itself conceding not a single electric generating unit is operating in the United States that deploys CCS. There is thus no sound legal basis to conclude that CCS is "adequately demonstrated" within the meaning of Section 111(b).

States are required to incorporate new source performance standards into their state environmental permits. Therefore, do you believe states would have standing to challenge these NSPS in courts once it is finalized?

States through public announcements and letters to EPA already have announced that the proposed rule will cause severe harm to their economies, citizens, businesses, and energy reliability if finalized. Certain states have identified impacts to utilities directly, which would increase the cost and jeopardize the reliability of energy, to the suppliers, providers, and transporters of coal and petroleum coke, and to industrial and residential consumers of electricity. Indeed, recently the state of Nebraska cited harm from the proposed rule itself in bringing the first challenge to the revised NSPS in federal court. These harms are sufficient to establish standing under Article III of the United States Constitution. In addition, the Supreme Court has held that states have "special solicitude" in establishing standing, which should further cement states' ability to satisfy the standing requirements in challenging the NSPS.

What are the implications of this new definition of the "Best System of Emission Reduction" (BSER)? Might it be used in other rules?

As described above, EPA's determination that a technology that is not commercially viable is nonetheless "adequately demonstrated" itself is unprecedented under the language of the Act, applicable case law, and past EPA practice. At the same time, this approach could have precedential impact beyond EGUs in several ways. First, as described below, the extraordinary stringency of these standards may set precedent for EPA's approach to guidelines for existing sources under Section 111(d), meaning that EPA could use a similar technology forcing approach to existing facilities. Second, it is anticipated that EPA will begin developing GHG standards under NSPS for other industrial and manufacturing sectors in the near future. EPA likely will rely on the approach it adopted for EGUs in establishing analogous standards for other sectors. Third, beyond greenhouse gases, EPA's unprecedented technology forcing approach could be cited in other NSPS for other types of pollutants as well, mandating a wide range of technologies under Section 111 that are not commercially demonstrated today.

SIDLEY AUSTIN LLP
SIDLEY

Honorable Chris Stewart
January 26, 2014
Page 3

Given the current state of the technology, if EPA identifies CCS as BESR for coal-fired EGUs, what would prevent EPA from finding that CCS is BESR for natural gas plants?

As the question points out, in the proposed NSPS, EPA identifies CCS as the Best System of Emissions Reduction (BSER) for coal facilities but not natural gas facilities. In recent months, certain groups have identified campaigns targeting new gas facilities from being constructed, despite their significant favorable greenhouse gas profile compared to coal. It would not be surprising--if not anticipated--that groups opposed to natural gas will make precisely this argument that EPA should require the same CCS technology for gas facilities that it does for coal. Thus it will be critical for EPA in the final rule to establish a firm record foundation for why it affirmatively believes that CCS should not be required for gas facilities.

EPA is under a consent decree to also issue NSPS on greenhouse gases for refineries in the near future. Do you think there will be an impact from this rule's definition of BESR? How might this affect the standards for refineries or for other manufactures? Do you think the new definition gives standing to companies in the oil and gas sector, so that they may challenge this rule? How about entities already under a NSPS like hospitals, grain elevators, and manufacturers? Could those entities have standing to challenge the GHG NSPS?

There are very few things that EPA does in a given rulemaking that do not flow over to and create precedent for other sectors and regulations. Thus, as pointed out by many of the manufacturing and industrial trade associations, there is significant concern that EPA's approach in this utility rule will create precedent for other sectors. Indeed, certain groups already are challenging PSD permits issued by EPA and other permitting agencies on the grounds that they do not incorporate CCS as BACT. There are numerous distinctions between how GHGs can be controlled from utilities and other sectors, as well as the ramifications of such regulations for energy intensive, trade sensitive industries, that must be considered and documented in this rulemaking to avoid this rule from spilling over into other sectors. EPA in the record should make it clear why proposed controls on utility GHGs have no precedential impact on other sectors for the reasons identified by these groups in their comments. Finally, there is no debate that other sectors will be impacted and harmed by this rule, including those that produce and transport coal and petroleum coke and those industries that rely on affordable and reliable energy. These industries, should they decide to challenge the NSPS, should be in a position to demonstrate these harms in establishing standing.

Can you explain the relationship between this rule and EPA's upcoming standards for existing sources? As you know, states have primacy in implementing standards for existing sources. Can you explain what this rule might mean for the Clean Air Act's cooperative federalist approach to establishing performance standards for existing power plants under Section 111 of the Act?

SIDLEY AUSTIN LLP
SIDLEY

The relationship between Section 111(b) and 111(d) is largely unchartered waters. EPA has issued Section 111(d) guidelines for existing sources on only a handful of occasions. Both the Act and the limited precedent demonstrate that states are to have primacy in implementing the existing source standards in their states. First, the Act explicitly provides that states are the regulatory agencies that implement the 111(d) guidelines for impacted sources in their states and that states shall have sufficient flexibility in doing so. Second, unlike Section 111(b) standards for new sources, Section 111(d) requirements are guidelines, and not exacting standards, and thus EPA itself should have significant flexibility to offer states a toolbox of options in satisfying Section 111(d) as opposed to a one size fits all mandate. Third, it is also implicit—if not explicit—in Section 111(d) that states should have sufficient time to implement the Section 111(d) requirements once EPA issues its guidelines. Here, under the schedule announced by the Administration, the states will have one year to develop their Section 111(d) approach upon the release of the EPA guidelines in June 2015. That time likely will be inadequate for many if not most states, and these deadlines themselves could frustrate cooperative federalism if EPA decides to implement the guidelines directly if a state cannot meet the limited one year window. Finally, although not directly presented by the question, I would point out there is significant legal doubt that EPA has any authority to impose Section 111(d) standards for existing utilities. The plain text of the Clean Air Act says that EPA lacks authority to impose Section 111(d) standards for existing sources when those sources are subject to a Section 112 National Emission Standard for Hazardous Air Pollutants (NESHAP). Because EGUs are subject to the Utility NESHAP under Section 112, EPA lacks authority to impose Section 111(d) standards on them at the same time.

Has EPA resolved potential issues regarding the classification of compressed carbon dioxide as an acid gas under both Superfund and the Resource Conservation and Recovery Act?

Your question highlights one of the fundamental flaws in EPA's analysis for concluding that CCS should be required for new facilities as the "best system of emissions reduction." In the preamble to the proposed rule, EPA focuses exclusively on the technical feasibility of CCS without any discussion of regulatory, economic, and pragmatic roadblocks to deploying the technology on a broader scale. For example, as your question points out, there are significant unresolved issues regarding the regulatory and legal authority to inject carbon under national, state, and local laws. Similarly, EPA's analysis presumes that there are sufficient geological formations in proximity to new sources where CCS can be deployed. A "*system* of emissions reduction" means exactly that and requires the system and infrastructure to be in place for the required technology to be deployed. EPA should ensure that before it mandates new standards it considers not only the technological feasibility, but also the full suite and system of regulatory, economic, and pragmatic considerations that apply.

Response to Honorable Randy Neugebauer

SIDLEY AUSTIN LLP
SIDLEY

Honorable Chris Stewart
January 26, 2014
Page 5

> **In July, I asked Mr. Chris Smith, the Acting Assistant Secretary of Fossil Energy at the Department of Energy about the timeline for the development of CCS technology. At that time, he could not give me a set timeline for when this technology would be truly ready for commercial use. Numerous states have determined that CCS is not economically or technically feasible for power plants, and the EPA itself stopped short of saying CCS was adequately demonstrated in April of 2012. What has changed substantively in CCS development in the last year and half?**

Your question fairly points out the flat inconsistency between EPA's conclusion in April of 2012 that CCS is not adequately demonstrated for purposes of Section 111(b) and its proposal in September of 2013 that CCS can be considered BSER for these same sources. EPA does not explain in the record the sharp change in its position over such a short period of time. This inconsistency and lack of rationale for the change in the record suggests that the change was one more based on a policy rationale to require CCS as opposed to any dramatic evolution in technology over this time frame.

***

I hope these questions are helpful in your efforts to continue to promote fairness, transparency, and public participation in settlements and consent decrees. I would be honored to offer any additional assistance to you and the Subcommittee.

Sincerely,

Roger R. Martella, Jr.

Appendix II

Additional Material for the Record

SUBMITTED BY REPRESENTATIVE KEVIN CRAMER

Fresh tech, difficult decisions

Basin Electric has a history of trying new technology

By Daryl Hill and Tracie Bettenhausen

Basin Electric has been the first to try many technologies. Just think of the cooperative's very first power plant, Leland Olds Station. When it went online in 1966, it was the largest plant in the Western Hemisphere to use lignite coal as a fuel source. And throughout its lifetime, it has been the proving ground for using and developing lignite.

More recently, the cooperative was the first to use GE's LMS100® simple cycle gas turbine at the Groton Generation Station in South Dakota.

Basin Electric staff prides itself in finding the best technology available. However, not every technology makes it past the first phases of study. Here's a look at some of the cooperative's latest ventures.

Lessons learned from carbon capture project

While the carbon capture project at Antelope Valley Station won't be going into demonstration phase at this time, benefit has come in the form of information – the first detailed analysis of carbon capture from a coal-based power plant in the region.

Basin Electric's directors decided in December that a proposed demonstration project to capture emissions of carbon dioxide (CO_2) at the Antelope Valley Station near Beulah, ND, will remain on hold until the economic viability of such a venture can be further developed.

This decision was made based on many factors including the results of a Front-End Engineering and Design (FEED) study presented at the December board meeting. The FEED study, which began in February 2010, focused on capturing a portion (about 25 percent) of the CO_2 from one of the Antelope Valley Station's two units. The FEED study, coupled with an assessment of the additions necessary at the plant, financing and sequestration costs indicated a demonstration-scale project could cost as much as $500 million.

Ron Harper, Basin Electric CEO and general manager, is satisfied with the effort. "The FEED study accomplished its purpose. This is the first time in the region a detailed analysis of a carbon capture project from a conventional coal-based power plant has been conducted," he says. "We now know the required infrastructure, the cost, and the integration and operational challenges that will be required to continue developing a carbon capture technology. In the current economic climate, we are postponing further investments for the time being, but regard it as important technology to consider for the future."

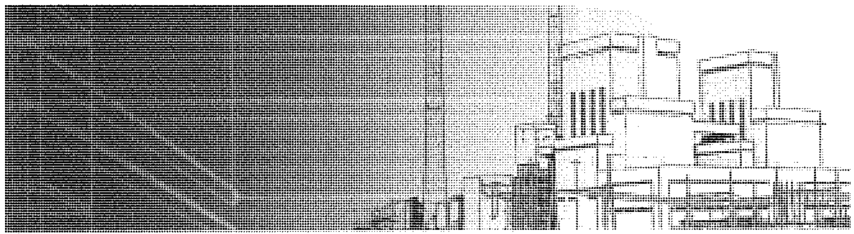
Harper says Basin Electric has been working on this project for more than three years and has made a huge investment in time, human resources and capital to come to this decision point. In addition to the overall cost of the project, other factors affecting the decision included:

- The market for the sale of CO_2 for enhanced oil recovery (EOR) is still developing in this region. Without EOR, additional costs for direct geologic sequestration would need to be included.
- The uncertainty of environmental legislation.
- Lack of a long-term energy strategy for the country.

Based on the FEED study, Basin Electric analyzed the technical, operational, regulatory and financial risks for installing carbon capture technology at a conventional coal-based power plant. "It's imperative that a revenue stream, such as EOR, be available to make a project like this viable," Harper says. "While a strong potential exists for CO_2 sales for EOR, they have not yet developed and there's no certainty they'll develop in the near future."

The FEED study was conducted in conjunction with HTC Purenergy, Regina, Saskatchewan, Canada, and Doosan Power Systems, Crawley, United Kingdom. HTC has designed a proprietary CO_2 capture technology, supported by Doosan, that is designed to capture 90 percent of the incoming CO_2 from the exhaust gases produced by one of the Antelope Valley Station units.

The cost of the FEED study was $6.2 million; about half ($2.7 million) of the study was funded by a grant from the North Dakota Industrial Commission. The remainder was funded by Basin Electric.



"With the information in hand, we know what the impacts of the costs and the operational challenges of a project like this will have on our consumers and how they would be affected if a full-scale implementation of this capture technology were to be employed.

"Basin Electric isn't willing to place the burden of developing CO_2 capture technology on its rural electric members," Harper says.

Even though the project is on hold for now, Harper says Basin Electric will continue to work with the Energy and Environmental Research Center in Grand Forks and the Plains CO_2 Reduction Partnership to research CO_2 storage technology.

Bacteria and coal gasification

For more than 25 years, an "energy park" near the Laramie River Station, Wheatland, WY, hasn't had a permanent tenant. By the end of 2011, that may change. At a recent board meeting, Basin Electric's directors granted permission to Ciris Energy, Centennial, CO, to build a demonstration project there.

According to Doug Rothe, mechanical/performance consulting engineer for Basin Electric, Ciris Energy plans to build a project to demonstrate coal gasification with a process similar to what naturally occurs to produce coal bed methane. They intend to use a chemical to dissolve the coal, and then bacteria to digest it and convert it into methane gas.

Rothe says Ciris is funding and building the project. "We're simply facilitating the demonstration plant by providing a location, coal supply and water supply, all at an appropriate cost to Ciris," he says. "They'll use up to five tons of coal a day, and will likely flare any gas produced. They have tested the technology at a lab in Colorado."

The energy park, owned by the Missouri Basin Power Project, features a warm water pipeline and vault, owned by the town of Wheatland, WY, where warmed water from the plant's cooling towers can be stored and used by a tenant if needed. The concept of an energy park is to use a byproduct from the power plant – in this case, warm water – for other purposes such as the Ciris project.

Rothe says the Ciris project is intended to be an inexpensive way to convert coal to a fuel with a lower carbon footprint. "By working with Ciris, we'll learn about the technology and will have an opportunity to work with them on a commercial venture in the future should the technology prove out."

Wind-to-Hydrogen project wraps up

The project's goal: Find a way to store wind energy through dynamic scheduling. Large amounts of electricity can't feasibly be stored in batteries because the batteries would be too big and expensive.

The Wind-to-Hydrogen project, located one mile south of Minot, ND, at North Dakota State University's Central Research Extension Center, was a demonstration project in partnership with the U.S. Department of Energy to explore storing energy from wind projects in the form of hydrogen. The project used an electrolyzer to produce hydrogen. An electrolyzer separates the hydrogen and oxygen contained in water. Software and controls were developed to select any of Basin Electric's wind projects and then dynamically schedule the electrolyzer's production of hydrogen in direct proportion of the output from that wind project. The hydrogen was stored and used as transportation fuel in three pickups adapted to use hydrogen.

Randy Bush, formerly Basin Electric's distributed resource coordinator,* says a major goal was to create the program and protocols to dynamically schedule electricity from the wind turbines to the electrolyzer. He says the project's goals have been accomplished and research completed. The DOE accepted the project's final report in June 2009.

"Dynamic scheduling allowed the electrolyzer to draw electric energy from the grid as it was produced by the wind turbines. The electrolyzer was being ramped up and down as dictated by the wind generation output," Bush says.

The DOE awarded Basin Electric just under $1.5 million in grants for the project.

*Randy Bush is now a buyer for Basin Electric.

SUBMITTED BY REPRESENTATIVE KEVIN CRAMER

DAVID B. McKINLEY, P.E.
1ST DISTRICT, WEST VIRGINIA

412 CANNON HOUSE OFFICE BUILDING
WASHINGTON, DC 20515
TEL: (202) 225-4172
FAX: (202) 225-7564
www.mckinley.house.gov

CO-CHAIR,
CONGRESSIONAL ARTHRITIS CAUCUS

CO-CHAIR,
CONGRESSIONAL YOUTH CHALLENGE CAUCUS

CO-CHAIR,
HIGH PERFORMANCE BUILDINGS CAUCUS

Congress of the United States
House of Representatives

COMMITTEE ON
ENERGY AND COMMERCE

SUBCOMMITTEE ON
ENERGY AND POWER

SUBCOMMITTEE ON
COMMERCE, MANUFACTURING AND
TRADE

SUBCOMMITTEE ON
ENVIRONMENT AND THE ECONOMY

October 23, 2013

The Honorable Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Dear Administrator McCarthy:

We are troubled by the EPA's announcement on September 30, 2013 entitled "EPA to Hold Public Listening Sessions on Reducing Carbon Pollution from Existing Power Plants." While hosting eleven public listening sessions held across the country in order to solicit feedback from the public is important, your plan leaves out those most impacted by the regulation by seeking input **only** in major urban areas.

While the proposed regulations on new and existing power plants may not be burdensome to cities such as Boston, San Francisco, Washington, D.C., or New York City, it will have significant impacts on businesses and families in rural areas. Already, one-fifth of our nation's coal plants, 204 facilities across 25 states, closed between 2009 and 2012. These closed and existing plants are **not** located in areas you are holding these listening sessions. In all fairness, residents and businesses in rural areas deserve to be heard just as much.

The EPA must hear from Americans on Main Street in rural America **not** downtown San Francisco or Washington, D.C. If the EPA really wants to learn the impact this regulation will have on mayors, store clerks, senior citizens, blue-collar Americans and others, you must hold these sessions in locations that produce coal and coal-fired electricity. We highly recommend that you and your colleagues take a step out of the Beltway and visit the places that make America great; the places your regulations continue to devastate by shuttering plants and killing jobs. These people need your help and want their views to be heard. Please add rural American communities in which coal and gas are a part of their economies to your locations for listening sessions.

Thank you for your attention to this matter, and we look forward to your thoughts.

Sincerely,

David B. McKinley, P.E.
Member of Congress

Shelley Moore Capito
Member of Congress

Congress of the United States
Washington, DC 20515

Lynn Westmoreland
Member of Congress

Marsha Blackburn
Member of Congress

Robert Aderholt
Member of Congress

Tim Huelskamp
Member of Congress

Steve Southerland
Member of Congress

Bill Johnson
Member of Congress

Cory Gardner
Member of Congress

Michael Turner
Member of Congress

Rodney Davis
Member of Congress

Kevin Brady
Member of Congress

Louie Gohmert
Member of Congress

Steve King
Member of Congress

Congress of the United States
Washington, DC 20515

Joe Barton
Member of Congress

Andy Barr
Member of Congress

Todd Young
Member of Congress

John Fleming
Member of Congress

Ted Yoho
Member of Congress

Ralph Hall
Member of Congress

Jeff Miller
Member of Congress

Blake Farenthold
Member of Congress

Steve Stivers
Member of Congress

Susan Brooks
Member of Congress

Kristi Noem
Member of Congress

Tom Cotton
Member of Congress

Congress of the United States
Washington, DC 20515

Mick Mulvaney
Member of Congress

Kevin Cramer
Member of Congress

Markwayne Mullin
Member of Congress

Bob Gibbs
Member of Congress

Jim Bridenstine
Member of Congress

Trent Franks
Member of Congress

David Schweikert
Member of Congress

Doug Lamborn
Member of Congress

Joe Wilson
Member of Congress

Paul Gosar
Member of Congress

Matt Salmon
Member of Congress

Todd Rokita
Member of Congress

Hal Rogers
Member of Congress

SUBMITTED BY THE HONORABLE CHARLES MCCONNELL

September 2011

Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations

Prepared for:

American Coalition for Clean Coal Electricity

Prepared by:

NERA

Economic Consulting

Project Team

David Harrison, Jr., Ph.D.
Andrew Foss
James Johndrow
Eugene Meehan
Bernard Reddy, Ph.D.
Anne Smith, Ph.D.

NERA Economic Consulting
200 Clarendon Street, 11th Floor
Boston, Massachusetts 02116
Tel: +1 617 927 4500
Fax: +1 617 927 4501
www.nera.com

Contents

Executive Summary

This report evaluates the potential energy and economic impacts of four major environmental regulations that would affect the electricity sector. The regulations include two major air emission policies—the Cross-State Air Pollution Rule (CSAPR) and regulation of mercury and other hazardous emissions (Utility MACT)—as well as policies to regulate coal combustion residuals (CCR) under the Resource Conservation and Recovery Act and to regulate cooling water intake under Section 316(b) of the Clean Water Act. We focus on the potential near- and medium-term (2012-2020) implications for electricity and other energy prices and for national economic impacts. This methodology is designed to complement analyses of individual regulations, including assessments of their social benefits and costs.

A. Background

Environmental legislation provides the mandate for the development of individual regulations. The U.S. Environmental Protection Agency (EPA)—sometimes in conjunction with state environmental agencies—develops regulations to implement these Congressional directives. EPA typically proposes a single regulation and provides information on its individual social costs and benefits (and other impacts), with previously-promulgated regulations being included in the baseline and the implications of other potential future regulations not considered.

In addition to analyses of individual regulations and their social costs and benefits, however, there are other impacts of environmental regulations that are of interest to policy makers but that are not necessarily included in regulatory analyses. Interest in "green jobs" has provided one additional focus. Some studies have noted that environmental mandates will increase employment in pollution control and clean technology sectors (see, e.g., Ceres 2010). Other commentators, however, have noted that these results ignore the jobs lost in the rest of the economy due to other impacts of the regulations, including increased electricity and other energy prices (see, e.g., Montgomery 2011).

There also has been a concern that focusing on individual regulations neglects the cumulative effects of multiple environmental regulations. Since these initiatives tend to increase future costs for coal-fired power plants, many studies have assessed the potential for regulations to lead to increases in coal unit retirements—since owners of some coal-fired power plants will choose to retire their units rather than install expensive control equipment—and some of these studies have assessed the possibility of impacts on electric system reliability.[1] Projections for a continuation of the recent trend of low electricity prices—driven by low natural gas prices—tend to increase pressures for coal unit retirements. Coal unit retirements and compliance costs for units that do not retire in turn can lead to increases in electricity and natural gas prices and decreases in coal prices. These changes in energy market conditions can lead to changes in output and employment.

1 See Bipartisan Policy Center (2011), Brattle Group (2010), Charles River Associates (2010b), Edison Electric Institute (2011), ICF International (2010), M.J. Bradley & Associates and Analysis Group (2011), and North American Electric Reliability Corporation (2010).

B. Objectives and Methodology of This Study

This study develops a set of models to evaluate the potential effects of various environmental regulations on energy markets and economic activity. This methodology thus complements those that have been developed to estimate the costs and benefits—and other impacts—of individual regulations.

Specifically, this report develops estimates of the effects over the period from 2012 to 2020 of the four environmental regulations—the two air emission regulations as well as CCR and Section 316(b)—in three major areas:

1. *Coal unit retirements.* These are estimates of the effects of potential costs on future coal unit retirements. As noted, we develop a probability distribution based upon the range of uncertain parameters.

2. *Electricity and other energy market impacts.* These impacts include the potential effects on energy markets—including coal, natural gas, and electricity—as well as on overall compliance costs.

3. *Economic impacts.* These effects include impacts on the U.S. economy, including employment, gross domestic product (GDP), and disposable personal income (i.e., personal income after taxes).

The modeling framework begins with a set of detailed estimates of the likely compliance technologies—and their costs—associated with the individual regulations. These assessments are based upon the requirements of the individual regulations, including taking into account the potential flexibility provided under CSAPR.[2] For the CCR and Section 316(b) regulations, we use EPA estimates of compliance costs for the various affected units. The result is a set of estimates of the potential technologies and costs to individual electricity generating units under the four policies.

The next task is to estimate the effects of these projected costs on future retirements of coal-fired power plants. The retirement model we develop is a Monte Carlo uncertainty model designed to predict potential economic retirements based upon comparisons of the future costs of the coal-fired unit in comparison to the costs of the likely new generation that would be added in the future. The model incorporates uncertainties in key parameters affecting this comparison, including control costs and electricity and fuel (notably natural gas) prices; the model also takes account of the feedback effects of coal unit retirements on electricity and fuel prices.

The estimated coal unit retirements and the estimated compliance costs for non-retiring units are then input to the U.S. Department of Energy's National Energy Model System (NEMS) model, a well-established modeling framework used by the Energy Information Administration (EIA) to evaluate energy and environmental policies. To develop estimates of changes in employment and

[2] The implications of the emissions trading provisions of CSAPR for technology choices at individual units are developed through an initial run of the NEMS model (a model that is described in the text).

other economic impacts, the NEMS results are input to the Policy Insight Plus model developed by Regional Economic Models, Inc. (REMI PI+), a model used extensively by numerous government agencies and private groups to assess the economic impacts of public and private policies.

Although we have attempted to develop comprehensive assessments, the results should be viewed as subject to considerable uncertainties beyond those incorporated in the analyses. Projected coal unit retirements, for example, do not include the effects of other potential regulatory requirements—notably those related to greenhouse gases—and the impacts do not include potential effects of coal unit retirements on (or constraints related to) electricity system reliability. These omitted factors could lead to additional impacts beyond those estimated in this study.

C. Results of This Study

1. Coal Unit Retirements

The potential costs of the four policies are estimated to lead to 39 gigawatts (GW) of prematurely retired capacity by 2015 among the current coal-fired power plants. This estimate represents additional retirements above those in the reference case (i.e., retirements predicted without the four regulations in place) and accounts for about 12 percent of the 2010 U.S. coal-fired electricity generating capacity.[3] As noted, this estimate does not include the potential effects of other potential requirements—notably potential greenhouse gas emission regulations—or concerns related to detailed electricity system reliability.

2. Energy Market Effects

As noted, the energy market impacts of the various regulations were estimated using the National Energy Modeling System (NEMS) based on estimates of the coal units that retire and the compliance costs for units that do not retire. The NEMS output includes estimates of overall compliance costs for the electric sector as well as detailed impacts on energy markets.

Table ES-1 summarizes the potential costs for the electricity sector based on the level of coal retirements predicted in the retirement model. These costs include compliance costs for coal units that do not retire, capital costs for new capacity that would replace retiring coal units, and changes in fuel costs. Costs are projected to be approximately $21 billion (in 2010$) per year over the period from 2012 to 2020. The costs represent a total of $127 billion (present value in 2010$ as of January 1, 2011) over the period from 2012 to 2020. Capital costs for environmental controls and replacement capacity are about $104 billion.[4]

[3] This level of retirements is estimated in the retirement model and is not influenced by utility retirement announcements.

[4] Capital costs exceed the total for environmental controls and replacement capacity because of net reductions in operating and maintenance costs.

Table ES-1. Electricity Sector Costs, 2012-2020 (billion 2010$)

	Annual Avg	PV
Environmental Controls	$15	$89
Replacement Capacity	$2	$11
Fuel	$5	$28
Total	$21	$127

Note: Compliance costs from 2012 through 2020 are discounted to January 1, 2011 using a real annual discount rate of 7 percent.
Annual average costs are based on the present values and discounting.
The cost of environmental controls includes net cost savings for operating and maintenance (O&M) expenses.

Source: NERA calculations as explained in text

The retirement of coal units and construction of replacement capacity affect electricity sector fuel consumption, fuel prices, and electricity prices. Table ES-2 summarizes the average potential energy market effects of the four regulations from 2012 to 2020. Appendix C provides information on the annual effects for 2012-2020, with effects that are both higher and lower than these average values.

Table ES-2. Average Annual Energy Market Impacts, 2012-2020

	Coal Retirements (GW)	Coal-Fired Generation (million MWh)	Coal Price at Minemouth (2010$/ton)	Gas-Fired Generation (million MWh)	Gas Price at Henry Hub (2010$/MMBtu)	Avg Retail Elec Price (2010$/MWh)
	Average of 2012-2020 Projections					
Reference	3.1	1,911	$33.54	639	$4.48	$86.87
CSAPR+MACT+CCR+316(b)	42.2	1,699	$31.61	765	$4.95	$92.52
	Change from Average of 2012-2020 Reference Projections					
CSAPR+MACT+CCR+316(b)	+39.1	-212	-$1.93	+126	+$0.48	+$5.65
	% Change from Average of 2012-2020 Reference Projections					
CSAPR+MACT+CCR+316(b)	+1241%	-11.1%	-5.7%	+19.7%	+10.7%	+6.5%

Note: Coal retirements are cumulative from 2010 through 2020.

Source: NERA calculations as explained in text

Coal-fired generation is projected to decrease by an average of 11.1 percent over the period from 2012 to 2020. The reduction in coal demand is projected to decrease coal prices by 5.7 percent on average. In contrast, the regulations are predicted to increase natural gas-fired generation by 19.7 percent on average over the period and increase Henry Hub natural gas prices by 10.7 percent on average. The increases in natural gas prices would lead to an estimated average increase in costs of about $8 billion per year for residential, commercial and industrial natural gas consumers, which translates into an increase of $52 billion over the 2012-2020 period (present value in 2010$ as of 2011 discounted at 7 percent). Average U.S. retail electricity prices are projected to increase by an average of 6.5 percent over the period. Information on the annual energy market effects from 2012 to 2020 is provided in Appendix C.

3. Economic Impacts

The potential economic impacts of the four policies were estimated using the REMI PI+ model. Table ES-3 summarizes the potential economic impacts. The table shows both the average annual changes over the period from 2012 to 2020 as well as the cumulative effects over the same time period. These net figures take into account jobs that would be created in some sectors as a result of spending on pollution controls (i.e., "green jobs") as well as jobs lost due to higher electricity prices and other negative impacts.

Table ES-3. U.S. Economic Impacts, 2012-2020

	Annual Average	Cumulative
Employment	-183,000 jobs	-1.65 million job-years
Gross Domestic Product	-$29 billion	-$190 billion
Disposable Personal Income	-$34 billion	-$222 billion
Disposable Personal Income per Household	-$270	-$1,750

Note: All dollar values are in 2010$.
The cumulative employment impact is an undiscounted sum from 2012 to 2020; the cumulative GDP and disposable personal income impacts are present values as of January 1, 2011 using a real annual discount rate of 7 percent.
Disposable personal income impacts per capita from REMI were converted to disposable personal income impacts per household based on a current average U.S. household size of 2.58 people (Census 2011).
Source: NERA calculations as explained in text

Over the period from 2012 to 2020, about 183,000 jobs per year are predicted to be lost on net due to the effects of the four regulations. The cumulative effects mean that over the period from 2012 to 2020, about 1.65 million job-years of employment would be lost. As noted, these net employment losses reflect net gains in some sectors and net losses in others. Of the 70 sectors in the REMI PI+ model, sectors that would gain jobs account for about 55,000 added jobs per year on average, and sectors that would lose jobs account for about 238,000 fewer jobs per year on average. On a cumulative basis over the period from 2012 to 2020, the sectors that would gain jobs represent about 499,000 job-years, and the sectors that would lose jobs represent about 2,149,000 job-years.

Table ES-3 also shows the potential near- to medium-term impacts on GDP and disposable personal income. U.S. GDP would be reduced by $29 billion each year on average over the period, with a cumulative loss from 2012 to 2020 of $190 billion (2010$). U.S. disposable personal income would be reduced by $34 billion each year on average over the period, with a cumulative loss from 2012 to 2020 of $222 billion (2010$). The average annual loss in disposable personal income per household is $270, with a cumulative present value loss of about $1,750 (2010$) over the period from 2012 to 2020. Annual economic impacts from 2012 to 2020 are provided in Appendix D.

I. Introduction

This report examines various effects of environmental regulations being developed by the U.S. Environmental Protection Agency (EPA) that affect the electric utility sector. We focus on the cumulative effects of four major environmental regulations on the energy sector and on economic activity, including employment and other measures.

A. Background

EPA has proposed major air emissions and other regulations in recent years. The two air regulations that are likely to have the greatest effect on the electric utility sector are the Cross-State Air Pollution Rule (CSAPR) and the regulations of mercury and other hazardous air emissions under Section 112 of the Clean Air Act (Utility MACT). These two regulations are at different stages of development. CSAPR was promulgated as a final rule in August 2011 (although there are some outstanding issues that EPA continues to review). Utility MACT was proposed in May 2011 and is expected to be made final in November 2011.

In addition to these two major air emissions rules, electric utility plants face other potential environmental regulatory requirements that would require additional investments. EPA recently has proposed a regulation under Section 316(b) of the Clean Water Act that regulates cooling water intake structures from electric power plants (and other facilities) in order to reduce losses to fish and other aquatic organisms. In addition, EPA has proposed regulations under the Resource Conservation and Recovery Act that would change how some plants manage their solid waste streams (the ashes from the burned coal and the sludge from their flue gas desulfurization (FGD) systems). Our assessments focus on the two air emission regulations and the 316(b) and CCR regulations; electricity generating units face environmental costs for other potential regulatory requirements—notably including those related to greenhouse gases—that are not included in our estimated impacts.

The EPA has developed assessments of the potential impacts of these various regulations and proposed regulations in separate regulatory impact analyses (RIAs). These RIAs provide important information on the potential social costs and social benefits of the proposed regulations as well as their potential effects on the energy sector. The public comments provide other information on the potential effects of the individual rules. Information on individual regulations, however, is limited because it does not measure the cumulative effects of many potential regulatory requirements either on individual power plants or on energy markets.

In the face of the limited information provided by evaluating individual regulations, various studies have evaluated the combined effects of various EPA regulations. Most of the studies have evaluated impacts on potential retirements of coal-fired units and some studies have estimated potential implications for electricity system reliability.[5] These studies differ substantially in the

[5] See Bipartisan Policy Center (2011), Brattle Group (2010), Charles River Associates (2010b), Edison Electric Institute (2011), ICF International (2010), M.J. Bradley & Associates and Analysis Group (2011), and North American Electric Reliability Corporation (2010). Note that the ability of these national studies to evaluate

environmental regulations they evaluate and in the nature of their evaluations. The prospect of substantial expenditures for pollution controls results in additional projected coal unit retirements, as every prior study has found.

The potential economic impacts of these rules—including their potential effects on employment and other measures of economic activity—have been less studied than their impacts on potential coal unit retirements, although some studies have considered potential economic impacts of some aspects of the regulations. For example, Ceres (2010) has developed estimates of the potential positive effects of the regulations on employment related to expenditures for emission controls. As various commentators have noted, however, this study did not provide information on the potential negative effects of higher electricity prices and other means of financing the added costs (see, e.g., Montgomery 2011). To our knowledge, no other study has estimated the cumulative economic impacts that include both the positive and negative effects of these four major regulations.

B. Objectives of This Report

The overall objective of this report is to provide estimates of the cumulative energy and economic effects of these four environmental regulations over the period from 2012 to 2020. That is, we consider the potential effects of these regulations on energy markets as well as on employment and other measures of economic activity. We have developed a modeling framework to estimate these various effects. We emphasize, however, that we have not developed estimates of the potential social benefits and social costs of these regulations and do not evaluate whether the individual regulations—or possible regulatory alternatives—would be desirable from a societal perspective.

In particular, the assessments presented in this study include the following three major types of effects.

1. *Coal unit retirements.* We consider the potential effects of regulatory requirements on coal unit retirement decisions based upon various key uncertainties, including the level of future natural gas and coal prices as well as the level of compliance costs. We use the results from this modeling framework to develop potential ranges of total U.S. coal unit retirements.

2. *Energy market effects.* We use information on predicted coal unit retirements as well as information on control costs for units that are not expected to retire to develop estimates of the potential effects of the policies on electricity and other energy markets. The results include estimates of the total compliance costs for the electricity sector due to the regulations, including control costs (capital as well as operation and maintenance), changes in fuel costs, and the costs of additional capacity added.

3. *Economic impacts.* The economic impacts of the regulations—including effects on employment, gross domestic product (GDP), and disposable personal income (i.e., personal

impacts on electricity system reliability is limited, since reliability impacts are likely to be sensitive to various system details (e.g., local transmission and voltage constraints) that are not included in the studies.

income after taxes)—are estimated by using the energy impacts in an economic impact model.

There are substantial uncertainties involved in developing these estimates. As discussed below, the model we use to develop estimates of coal unit retirements incorporates key uncertainties. It is important to emphasize, however, that other uncertainties are not modeled—including the possibility that coal and other units will face potential regulations related to greenhouse gases—and thus the projections presented in this report should be viewed as estimates of the likely impacts of only the four policies evaluated.

C. Outline of This Report

The remainder of this report is organized as follows. Chapter II provides an overview of the methodologies that are used and the policies that are evaluated in the study. Chapter III presents the results of the analyses. The appendices provide details on the models, compliance assumptions, methodologies, and results.

II. Overview of Methodologies and Policies

This chapter provides summary information on the methodologies used to estimate the potential economic impacts of the four policies. We also provide overviews of the four environmental policies that are modeled. Additional details of the models, policies, and data are provided in the appendices.

A. Modeling Framework

The methodology used in this study is based upon a set of linked models designed to assess the energy and economic impacts of environmental regulations affecting the electric utility sector. The empirical estimates of policy impacts are developed by comparing impacts under a baseline case (i.e., a case without the policies in place) and impacts under the policy case.

1. Overview of Modeling Framework

The modeling framework consists of three principal elements:

1. *Retirement Model*, which estimates whether coal units would be expected to retire based upon comparisons of the expected value of the future costs for the coal unit—including the likely potential costs of additional environmental controls—and the expected costs of an equivalent new natural gas combined cycle unit;

2. *National Energy Modeling System* (NEMS) model developed by the U.S. Energy Information Administration (EIA), which we use to assess the likely effects of compliance costs and coal unit retirements on the energy markets; and

3. *Policy Insight Plus model developed by Regional Economic Models, Inc. (REMI PI+),* which we use to develop estimates of the economic impacts of energy market effects.

The following sections provide summaries of these elements.

2. Coal Unit Retirement Model

Power companies face the choice of retrofitting existing coal units to meet regulations or retiring them if the future costs do not justify continued operation in light of the likely costs of alternative sources to meet future electricity demand. We developed a detailed model to evaluate whether existing coal units in the United States would be expected to retire taking into account the potential costs of retrofit (and other future costs) as well as uncertainties in energy prices and other factors.

The retirement model is designed to mirror the decision by power companies on whether to retrofit coal-fired units with environmental controls or retire them and replace them with new capacity. A Monte Carlo formulation takes into account major uncertainties involved in this decision.

The model begins with estimates of the potential additional costs related to environmental policies. The potential future costs for coal units are based upon EIA data on unit characteristics (including capacity, capacity factor, heat rate, O&M costs, coal type, and current environmental controls) and on EPA information on the potential costs of the various controls. The potential technologies and costs for each coal-fired unit also reflect the flexibility that CSAPR provides—due to the potential for emissions trading—as well as the fuel and electricity prices based upon a similar level of retirements.[6] The model thus takes account of the feedback effects of coal unit retirements on electricity and fuel prices.

The model uses statistical techniques and EPA data to simulate hourly electricity prices in each region—as a function of natural gas prices, time of day, season, peak/off-peak, and other factors—and generation decisions by coal units and potential replacement capacity, with generation a function of price and marginal cost. Uncertain parameters include the costs of controls, fuel prices and electricity prices, and the costs of the likely replacement alternative (a new natural gas combined cycle unit), with interactions among the uncertain parameters included in the Monte Carlo formulation.

Future coal unit costs are compared with the future costs of a new natural gas combined cycle unit by calculating the difference between the cost of the coal unit and the cost of the natural gas alternative in each of the 100 Monte Carlo draws. The unit is presumed to retire if the expected value of the cost difference is positive, i.e., on expectation, the coal unit would have greater future costs than a new natural gas combined cycle unit. Existing coal unit remaining lifetimes in these calculations are assumed to range between 10 and 20 years, depending upon unit age in 2015, to reflect the likelihood that owners of older units will have a shorter time horizon for recovering the cost of additional controls. The formulation accounts for the costs of using system energy during hours when coal units and the potential replacement capacity would not run.

3. NEMS Model

The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system of the U.S. through 2030. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS was designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE).

4. Regional Economic Models, Inc. Policy Insight Plus Model

The Regional Economic Models, Inc. (REMI) Policy Insight Plus (PI+) model produces estimates of the changes in employment, GDP, disposable personal income, and other macroeconomic variables due to changes in supply, demand, prices, and other types of inputs. Each version of the REMI PI+ model is custom-built for the regions of interest, which can range

[6] We develop the implications of emissions trading flexibility provided by CSAPR by running the NEMS model with the relevant caps. The technologies identified in this run for each unit are used in the retirement model.

from counties to entire countries. The REMI PI+ model incorporates detailed and up-to-date macroeconomic data from the U.S. Bureau of Economic Analysis, the U.S. Bureau of Labor Statistics, the U.S. Census Bureau, and other public sources. The REMI PI+ model is widely used by federal, state, and local agencies, as well as analysts in the private sector and academia, to estimate the effects of regulations, investments, closures, and other scenarios.

B. Overview of Policies Modeled

This section summarizes the four policies evaluated in this report, including the two air emission regulations (CSAPR and Utility MACT) as well as Section 316(b) and CCR. Appendix A provides details on how the reference case and the four policies are modeled, including information on the control cost assumptions that are used.

1. Reference Case

The version of NEMS used for the model represents current legislation and environmental regulations as of January 31, 2011. The policies included in the reference case include state requirements for reduction of mercury emissions but not the Clean Air Mercury Rule, which was vacated and remanded by the D.C. Circuit Court of the U.S. Court of Appeals on February 8, 2008. The reference case also includes the temporary reinstatement of the SO_2 and NOx cap-and-trade programs included in the Clean Air Interstate Rule (CAIR) as a result of the ruling issued by the United States Court of Appeals for the District of Columbia on December 23, 2008.[7] CAIR is included in the reference case through 2011. From 2012 onward, SO_2 and NOx caps revert to pre-CAIR levels.

Proposed federal and state legislation, regulations, or standards—and sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in the reference case. The excluded policies include the four policies evaluated in our study.[8]

2. Cross-State Air Pollution Rule

EPA promulgated CSAPR in August 2011, following a draft rule (Clean Air Transport Rule, or CATR) proposed in August 2010 as a replacement to CAIR. CSAPR requires 27 states to reduce power plant emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from power plants in Eastern states in an effort to improve ozone and fine particulate air quality in other downwind states.[9] Under CSAPR, EPA set new limits on SO_2 and NO_x emissions for each state beginning in 2012. The limits tighten in some states in 2014.

---

7 EPA finalized CAIR in 2005 but the rule was remanded to EPA by the D.C. Circuit Court of Appeals in 2008. The court decision required EPA to develop a different regulatory approach but to implement CAIR in the meantime.

8 Note that we include CSAPR in our assessments although EPA finalized CSAPR in August 2011 (EPA 2011a).

9 In a separate but related regulatory action, EPA also issued a supplemental notice of proposed rulemaking to require six states to make summertime NOx reductions under the CSAPR ozone-season program. Finalizing this

3. Utility MACT

EPA proposed the Utility MACT rule in May 2011 to reduce emissions of mercury and other hazardous air pollutants (including other hazardous metals and acid gases) from coal- and oil-fired power plants across the country. The rule would set emission rate standards for different types of coal- and oil-fired units based on maximum achievable control technology. The emission rate standards would apply to mercury, other non-mercury metallic hazardous air pollutants (using particulate matter as a proxy), and acid gases (using hydrogen chloride as a proxy). Covered power plants would have up to three years to comply with the rule, but permitting authorities could grant one-year extensions to power plants if they required additional time.

4. Coal Combustion Residuals

EPA issued a proposed rule on June 21, 2010 related to the regulation of coal combustion residuals (also referred to as coal combustion waste) under the Resource Conservation and Recovery Act (RCRA). The regulations apply to the management of coal combustion residuals generated by steam electric power plants (i.e., electric utilities and independent power producers) that are disposed of in landfills and surface impoundments.

EPA co-proposed two approaches to the regulation of coal combustion waste. The first would regulate residuals under Subtitle C of RCRA as a "special waste." The second would regulate residuals under Subtitle D as a non-hazardous waste. Our assessments are based on the potential costs to individual units of regulating coal combustion residuals under Subtitle D.

5. Clean Water Act Section 316(b)

On April 20, 2011, EPA proposed cooling water intake requirements for existing power plants and other industrial facilities under Section 316(b) of the Clean Water Act. These facilities withdraw water and in the process, fish and other aquatic organisms are lost if they become trapped against intake screens ("impingement") or pulled into the cooling system ("entrainment"). Various technologies reduce impingement and entrainment losses, including the retrofit of plants with cooling towers to provide closed-cycle cooling.

EPA evaluated four alternatives for setting Section 316(b) standards, with Option 1 identified as its preferred option. Option 1 would require that existing plants withdrawing water above a proposed 2 million gallon per day threshold reduce the impingement mortality by meeting various national standards (EPA 2011b, pp. 22203-22204). In contrast, entrainment controls would be set on the basis of site-specific requirements. Under EPA's proposal, permit writers will be required to consider converting the condenser cooling system from once-through cooling to closed-cycle cooling through the use of cooling towers, which reduces net flow and thus entrainment losses (albeit at substantial cost and often undesirable environmental side-effects). EPA estimated the cost of installing cooling towers under Option 1 at the 46 fossil units with the

supplemental program would bring the total number of covered states under the CSAPR to 28. EPA reports that it is proposing to finalize this proposal by late fall 2011.

largest cooling water withdrawals from tidal waters. Our assessments are based on the potential costs to individual units of the Option 1 alternative.

III. Study Results

This chapter summarizes the study results for our analyses of the cumulative energy and economic impacts of the four environmental policies. The results are grouped into three categories: (1) coal unit retirements; (2) energy market effects; and (3) economic impacts. Additional details are provided in the appendices.

A. Coal Unit Retirements

1. National Results

The potential costs of the four policies are estimated to lead to 39 gigawatts (GW) of prematurely retired capacity among the current coal-fired power plants. This figure represents additional retirements above those in the reference case (i.e., retirements predicted without the four regulations in place) and accounts for about 12 percent of the 2010 U.S. coal-fired electricity generating capacity. As noted, this estimate does not include the potential effects of other potential requirements—notably potential greenhouse gas emission regulations—or concerns related to detailed electricity system reliability.

We developed an assessment of the potential range of possible retirements using the information from the 100 individual draws from the retirement model. We calculated the retirements in each of the draws as a sensitivity analysis, assuming that a unit would retire if its future costs were greater that the future costs of the natural gas unit in those circumstances. The range of retirements was from 17 GW to 79 GW in these 100 cases. This range is roughly consistent with sensitivity results from other studies, although the other studies do not use the same assumptions and methodology.[10]

2. Uncertainties Regarding Estimated Retirements

The range of potential retirements provides an indication of the substantial uncertainty surrounding potential retirements due to uncertainties in future natural gas prices, control costs and other factors influencing individual retirement decisions. There are, however, some factors that are not included in the retirement model. The retirement model does not account for the possibility that adjustments could occur if the local effects of retirements were severe (e.g., likely to impair electricity system reliability). These adjustments would tend to reduce the actual level of retirements below those predicted by our model, which is based upon economic calculations, although the potential impacts on electricity prices could be greater than estimated assuming units are allowed to retire.

In addition, the model does not factor into the calculation of expected future costs the potential costs and other impacts associated with greenhouse gas regulations. Even without the prospect of

[10] EIA, for example, reports a range of retirements for the two air emissions regulations from 4.7 GW to 63.8 GW (net of reference case retirements) depending upon the level of future natural gas prices as well as the likely time horizon for amortizing compliance capital costs (EIA 2011, p. 50).

specific regulatory requirements, owners of coal-fired power plants are likely to reflect the prospect of potential greenhouse gas regulations in their decisions on whether to incur large compliance expenditures or retire their units. Our estimates do not take into account these effects, which would lead to greater coal unit retirements.

3. Regional Results

The expected coal unit retirements differ substantially among electricity regions. Table 1 shows the potential coal unit retirements by North American Electric Reliability Corporation (NERC) region.[11] The table also shows the percentage of 2010 coal capacity in each region that is predicted to retire by 2015 and each region's share of total U.S. retirements. Note that most retirements are in the Mid-Atlantic and Great Lakes and Southeast regions. These results are consistent with the results of other studies (e.g., Brattle Group 2010).

Table 1. Regional Retirement Estimates

		2010 Coal Capacity (GW)	Retirements (GW)	% of Regional 2010 Coal Cap	% of Total Retirements
	U.S. Total	318.1	39.1	12%	100%
NERC Regions					
NPCC	Northeast	5.7	1.3	22%	3%
RFC	Mid-Atlantic and Great Lakes	107.8	14.5	13%	37%
SERC	Southeast	98.5	18.0	18%	46%
FRCC	Florida	10.3	0.1	1%	0%
MRO	Upper Midwest	28.8	1.9	6%	5%
SPP	Oklahoma and Kansas	19.0	1.6	9%	4%
ERCOT	Texas	18.2	0.6	3%	1%
WECC	West	29.8	1.2	4%	3%

Source: NERA calculations as explained in text

B. Electricity and Energy Market Impacts

As described in the previous section, we used NEMS to estimate net changes in coal-fired generation, natural gas-fired generation, fuel prices, and electricity prices as a result of coal unit retirements and environmental controls due to the four policies.

1. National Results

Table 2 summarizes the potential costs for the electricity sector based on the level of coal retirements predicted in the retirement model. These costs include compliance costs for coal units that do not retire, capital costs for new capacity that would replace retiring coal units, and changes in fuel costs. Costs are projected to be approximately $21 billion (in 2010$) per year over the period from 2012 to 2020. The costs represent a total of $127 billion (present value in

[11] NEMS provides information for 22 regions; we have aggregated the results into the eight major NERC regions.

2010$ as of January 1, 2011) over the period from 2012 to 2020. Capital costs for environmental controls and replacement capacity are approximately $104 billion.[12]

Table 2. Electricity Sector Costs, 2012-2020 (billion 2010$)

	Annual Avg	PV
Environmental Controls	$15	$89
Replacement Capacity	$2	$11
Fuel	$5	$28
Total	$21	$127

Note: Compliance costs from 2012 through 2020 are discounted to January 1, 2011 using a real annual discount rate of 7 percent.
Annual average costs are based on the present values and discounting.
The cost of environmental controls includes cost savings for operating and maintenance (O&M) expenses.
Source: NERA calculations as explained in text

Table 3 summarizes the average effects of the four policies at the national level over the period from 2012 to 2020. (Detailed annual impacts are provided in Appendix C, with effects that are both higher and lower than these average values.)

Table 3. Average Annual Energy Market Impacts, 2012-2020

	Coal Retirements (GW)	Coal-Fired Generation (million MWh)	Coal Price at Minemouth (2010$/ton)	Gas-Fired Generation (million MWh)	Gas Price at Henry Hub (2010$/MMBtu)	Avg Retail Elec Price (2010$/MWh)
	Average of 2012-2020 Projections					
Reference	3.1	1,911	$33.54	639	$4.48	$86.87
CSAPR+MACT+CCR+316(b)	42.2	1,699	$31.61	765	$4.95	$92.52
	Change from Average of 2012-2020 Reference Projections					
CSAPR+MACT+CCR+316(b)	+39.1	-212	-$1.93	+126	+$0.48	+$5.65
	% Change from Average of 2012-2020 Reference Projections					
CSAPR+MACT+CCR+316(b)	+1241%	-11.1%	-5.7%	+19.7%	+10.7%	+6.5%

Note: Coal retirements are cumulative from 2010 through 2020.
Source: NERA calculations as explained in text

The potential impacts of the four policies on energy markets are substantial.

- Coal-fired generation is predicted to decrease substantially, by an average of 11.1 percent relative to average reference case levels over the 2012-2020 period.
- In contrast, natural gas-fired generation is predicted to increase substantially, by an average of 19.7 percent relative to average reference case levels over the same period.

[12] Capital costs exceed the total for environmental controls and replacement capacity because of net reductions in operating and maintenance costs.

- Average coal prices are predicted to decline, reflecting the reduction in coal-fired generation. Coal prices decline an average of 5.7 percent relative to average reference case levels over the same period.
- Average natural gas prices are predicted to increase, reflecting the increased demand for gas-fired generation. Henry Hub natural gas prices increase an average of 10.7 percent relative to average reference case levels over the 2012-2020 period. These prices increases would increase costs by about $8 billion per year for residential, commercial, and industrial customers (and a total of about $52 billion as a present value as of January 1, 2011 over the period).
- Average retail electricity prices are predicted to increase an average of 6.5 percent over the same period.

It is useful to put these predicted impacts into perspective. For example, the predicted effect of the four policies on Henry Hub natural gas prices is $0.48/MMBtu. By way of context, the EIA reduced its forecast of future Henry Hub natural gas prices by approximately $2/MMBtu from AEO 2009 to AEO 2011.

2. Uncertainties Regarding Energy Market Impacts

The projected energy market impacts due to the four environmental policies are significant. The impacts arise both because of substantial compliance costs—that lead a substantial number of coal-fired units to retire and force other coal units to incur substantial retrofit costs in order to comply—and because of the market reactions to these initial impacts.

The impacts depend upon many factors, including the baseline conditions—including projected future natural gas prices—as well as the details of the market reactions to the policy changes that are embedded in the NEMS model. The baseline also includes assumptions on the nature of future regulatory requirements. As noted above, we modified the baseline in NEMS to evaluate the impacts of these air emission policies relative to the absence of similar SO_2 and NOx policies (no CAIR from 2012 onward); EPA made the same assumption in its recent analysis of CSAPR. We have included state mercury requirements in the baseline, which tend to decrease the impacts relative to a baseline without the state requirements.

The electricity market impacts also depend upon a host of specific elements of the electricity systems in various regions. Some of these elements are included in the assessments, such as the nature of the state regulatory regime. The NEMS results, however, do not include considerations related to highly location-specific factors such as transmission security and the time constraints on retiring units, particularly relatively large units (ICF 2011).

3. Regional Results

NEMS provides energy price results for various regions, including 22 electricity price regions. The electricity price impacts of the four policies differ by region depending upon many factors including the following:

- reliance on coal-fired generation under baseline conditions;
- coal unit retirements;
- need for replacement capacity;
- type of replacement capacity that NEMS builds;
- retrofits for coal units that continue to operate as well as the costs of those retrofits;
- capacity factors for coal units;
- regional fuel prices;
- interregional electricity trade; and
- regulatory regime.

Table 4 provides estimates of the percentage increases in retail electricity rates in the 22 NEMS electricity regions due to the four policies. As with the prior results, these figures are based upon the average percentage changes over the period from 2012 to 2020. (Detailed annual impacts are provided in Appendix C, with effects that are both higher and lower than these average values.)

Table 4. Average Electricity Price Impacts, 2012-2020

		2010$/MWh	%
	US Average	+$5.65	+6.5%
NEMS Regions			
NEWE	New England	+$2.93	+2.2%
NYCW	NYC	+$6.97	+4.2%
NYLI	NY Long Island	+$13.00	+8.0%
NYUP	NY Upstate	+$6.39	+5.6%
RFCE	Mid-Atlantic	+$10.38	+10.7%
SRVC	VA & Carolinas	+$4.05	+5.1%
SRSE	Southeast	+$6.94	+8.2%
FRCC	Florida	+$4.10	+3.9%
RFCM	Lower MI	+$7.63	+9.6%
RFCW	OH, IN, & WV	+$7.01	+8.6%
SRCE	KY & TN	+$8.36	+13.5%
MROE	WI & Upper MI	+$6.96	+9.2%
MROW	Upper Midwest	+$5.39	+7.8%
SRGW	South IL & East MO	+$6.73	+11.1%
SPNO	KS & West MO	+$6.42	+8.0%
SRDA	AR, LA, & West MS	+$5.16	+7.2%
SPSO	Oklahoma	+$8.75	+12.6%
ERCT	Texas	+$5.34	+6.9%
RMPA	CO & East WY	+$1.40	+1.5%
NWPP	Northwest	+$0.04	+0.1%
AZNM	AZ & NM	+$1.40	+1.6%
CAMX	California	+$2.25	+1.6%

Source: NERA calculations as explained in text

C. Economic Impacts

As noted, we used the REMI PI+ model to estimate the potential near- and medium-term economic impacts of the four policies based upon the energy market impacts estimated in NEMS.

1. Results

Table 5 summarizes the effects of the four policies on various economic impact measures, including impacts on employment, GDP, and disposable personal income. The table includes information on the average annual changes over the period from 2012 to 2020 as well as the cumulative effects over the period (detailed annual impacts are provided in the appendices).

Table 5. U.S. Economic Impacts, 2012-2020

	Annual Average	Cumulative
Employment	-183,000 jobs	-1.65 million job-years
Gross Domestic Product	-$29 billion	-$190 billion
Disposable Personal Income	-$34 billion	-$222 billion
Disposable Personal Income per Household	-$270	-$1,750

Note: All dollar values are in 2010$.
The cumulative employment impact is an undiscounted sum from 2012 to 2020; the cumulative GDP and disposable personal income impacts are present values as of January 1, 2011 using a real annual discount rate of 7 percent.
Disposable personal income impacts per capita from REMI were converted to disposable personal income impacts per households based on a current average U.S. household size of 2.58 people (Census 2011).
Source: NERA calculations as explained in text

Over the period from 2012 to 2020, about 183,000 jobs per year are predicted to be lost on net due to the effects of the four regulations. The cumulative effects mean that over the period from 2012 to 2020, about 1.65 million job-years of employment would be lost. U.S. GDP would be reduced by $29 billion each year on average over this period, with a cumulative loss from 2012 to 2020 of $190 billion (2010$). U.S. disposable personal income would be reduced by $34 billion each year on average over this period, with a cumulative loss from 2012 to 2020 of $222 billion (2010$). The average annual loss in disposable personal income per household is $270, with a cumulative loss of $1,750 (2010$).

The four policies would lead to different net employment impacts on different sectors. Of the 70 sectors in the REMI PI+ model, sectors that would gain jobs account for about 55,000 added jobs per year on average, and sectors that would lose jobs account for about 238,000 fewer jobs per year on average. On a cumulative basis over the period from 2012 to 2020, the sectors that would gain jobs represent about 499,000 job-years, and the sectors that would lose jobs represent about 2,149,000 job-years.

2. Uncertainties Regarding Economic Impacts

The estimated economic impacts of the four environmental policies over the period from 2012 to 2020 are substantial. These impacts include many factors, including: the positive impacts of expenditures on environmental controls and replacement electricity capacity; the negative effects of reduced coal sales and reduced coal production; the positive effects of increased natural gas sales; both the negative effects of higher natural gas prices on consumers and the positive effects on producers; and the negative effects of electricity price effects on consumers. In addition, the timing of impacts depends upon how the capital costs of pollution controls and increased replacement capacity are financed. The overall impacts are thus a complicated result of a large number of positive and negative factors.

These estimates are subject to various types of uncertainties, including uncertainties regarding the energy market and other inputs. As noted above, the coal unit retirements and energy market impacts are subject to various uncertainties, which translate into uncertainties regarding the economic impacts. There are additional uncertainties regarding the modeling of these economic impacts. The macroeconomic modeling does not, for example, take into account the potential negative effect on the overall productivity and growth of the economy of reduced productive investment due to the financing of pollution control expenditures. The model also does not presume that environmental compliance expenditures use any unemployed or idle resources. In addition, the model assumes that consumers can shift away from more expensive energy and thus reduce the negative impacts of higher natural gas and electricity prices, an assumption that may understate the likely negative impacts of the price increases.

IV. References

Bipartisan Policy Center. 2011. *Environmental Regulation and Electric System Reliability.* Washington, D.C.: Bipartisan Policy Center.

Brattle Group. 2010. *Potential Coal Plant Retirements Under Emerging Environmental Regulations.* Cambridge, MA: Brattle Group, December 8.

Ceres. 2011. *New Jobs—Cleaner Air: Employment Effects Under Planned Changes to the EPA's Air Pollution Rules.* Report prepared by the University of Massachusetts Political Economy Research Institute. Boston: Ceres, February.

Charles River Associates. 2010a. *Prospects for an EPA-Driven Capital Crisis for Utilities.* Boston, MA: CRA, September.

Charles River Associates. 2010b. *A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT.* Washington, D.C.: CRA, December.

Edison Electric Institute. 2011. *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet.* Report prepared by ICF International. Washington, D.C.: EEI, January.

Electric Power Research Institute. 2010. *Cost Analysis of Proposed National Regulation of Coal Combustion Residuals from Electric Generating Industry.* Palo Alto, CA: EPRI, November.

ICF International. 2010. *Clean Air, Ash and Water Regulations: Potential Impact of EPA Proposed Rules.* Fairfax, VA: ICF, October.

ICF International. 2011. *Retiring Coal Plants While Protecting System Reliability.* Fairfax, VA: ICF, August.

M.J. Bradley & Associates and Analysis Group. 2011. *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability.* Concord, MA: M.J. Bradley & Associates, June.

Montgomery, W. David. 2011. *Prepared Testimony of W. David Montgomery, Ph.D., before the Senate Committee on Environment and Public Works, Subcommittee on Green Jobs and the New Economy.* February 15.

North American Electric Reliability Corporation. 2010. *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations.* Princeton: NERC, October.

U.S. Census Bureau. 2011. "Profile of General Population and Housing Characteristics: 2010." (factfinder2.census.gov/faces/nav/jsf/pages/index.xhtml, accessed September 20, 2011)

U.S. Energy Information Administration. 2011. *Annual Energy Outlook 2011.* Washington, D.C.: EIA, April. (www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2005. "Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NOX SIP Call; Final Rule." 70 *Federal Register* 25162. Washington, D.C.: EPA, May 12.

U.S. Environmental Protection Agency. 2010. "Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone; Proposed Rule." 75 *Federal Register* 45210. Washington, D.C.: EPA, August 2.

U.S. Environmental Protection Agency. 2011a. "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals." 76 *Federal Register* 48208-48483. Washington, D.C.: EPA, August 8. (www.gpo.gov/fdsys/pkg/FR-2011-08-08/pdf/2011-17600.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011b. "National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities; Proposed Rule." 76 *Federal Register* 22174-22288. Washington, D.C.: EPA, April 20. (www.gpo.gov/fdsys/pkg/FR-2011-04-20/pdf/2011-8033.pdf, accessed September 20, 2011)

Appendix A: Compliance Measures and Cost Estimates

This appendix provides information on the data and methodologies used to model potential compliance measures and compliance costs at coal units for relevant environmental policies in the reference case and the four potential EPA regulations (CSAPR, MACT, CCR, and 316(b)). We begin with information related to the reference case and then provide information related to each of the potential EPA regulations. We present our cost assumptions for air emission control technologies, which we used as inputs for both the reference case and policy case, at the end of this appendix.

A. Reference Case

As discussed in the report body, we modeled the energy market impacts of the potential EPA regulations using the National Energy Modeling System (NEMS), a comprehensive U.S. energy model developed and maintained by the U.S. Energy Information Administration (EIA). With the exception of the environmental policy inputs discussed in this appendix, we used the same inputs to NEMS as EIA used for its *Annual Energy Outlook* (*AEO*) *2011* (EIA 2011a). Note that the inputs for *AEO 2011* which we did not modify include inputs related to various national, regional, and state environmental policies that are currently in place, such as state renewable portfolio standards and the Regional Greenhouse Gas Initiative.

The environmental policies in the reference case that are most relevant to the potential EPA regulations are the Clean Air Interstate Rule (CAIR) to reduce SO_2 and NO_x emissions from power plants and policies to reduce mercury emissions from power plants. EIA describes its inputs related to these policies for *AEO 2011* in EIA (2011b, pp. 104-107). Table A-1 summarizes our compliance assumptions related to these policies for our reference case.

Table A-1. Compliance Assumptions for Reference Case

Policy	Emission	Compliance Assumptions
CAIR	SO_2	Apply Phase 1 SO_2 cap (3.6 million tons) through 2011 and allow NEMS to determine which units would need to install SO_2 control technologies or switch to lower-sulfur coal in the interstate cap-and-trade program; from 2012 onward, allow SO_2 cap to revert to pre-CAIR level (based on Acid Rain Program)
	NO_x	Apply Phase 1 NO_x cap (1.5 million tons) through 2011 and allow NEMS to determine which units would need to install NO_x control technologies in the interstate cap-and-trade program; from 2012 onward, allow NO_x cap to revert to pre-CAIR level (based on NO_x Budget Trading Program)
State policies	Mercury	Include mercury reductions as required by state policies and allow NEMS to determine which units would need to install mercury control technologies

Source: NERA assumptions as explained in text

1. Clean Air Interstate Rule

EPA promulgated CAIR in 2005 to reduce SO_2 and NO_x emissions from power plants in 28 Eastern states (EPA 2005).[1] EPA established interstate cap-and-trade programs for both types of emissions. The caps for both types of emissions became tighter over two phases. The NO_x program consisted of Phase 1 (2009-2014) with a cap of 1.5 million tons and Phase 2 (2015 onward) with a cap of 1.2 million tons. The SO_2 program consisted of Phase 1 (2010-2014) with a cap of 3.6 million tons and Phase 2 (2015 onward) with a cap of 2.5 million tons. In December 2008, the U.S. Court of Appeals for the D.C. Circuit remanded CAIR to EPA but did not vacate it, thus allowing the first phases of the NO_x and SO_2 programs to take effect while EPA developed a replacement rule.

Our modeling for the reference case reflects that the CAIR Phase 1 programs have taken effect. We applied the CAIR Phase 1 caps for SO_2 and NO_x emissions (using EIA's inputs for *AEO 2011*) through 2011 and allowed NEMS to decide which units would need to install SO_2 control technologies or switch to lower-sulfur coal in the interstate cap-and-trade program. Our NEMS inputs for the reference case also include the SO_2 and NO_x control technologies that coal units have installed or have announced that they will install to comply with CAIR requirements (or any state or local policies requiring reductions in these emissions). EIA (2011, p. 106) summarizes the recent and planned retrofits for SO_2 and NO_x policies that are in NEMS.

As discussed in the report body and below, EPA has promulgated the Cross-State Air Pollution Rule (CSAPR) as a replacement for CAIR to take effect in 2012 (EPA 2011a). CSAPR would cover a somewhat different set of Eastern states than CAIR but would also involve interstate cap-and-trade programs and would set the caps at similar levels to CAIR. Thus, including CAIR in our reference case from 2012 onward would make it difficult to isolate the incremental impacts of CSAPR. We therefore terminated the CAIR Phase 1 caps after 2011 in our reference case and reverted SO_2 and NO_x caps to pre-CAIR levels (based on the Acid Rain Program and NO_x Budget Trading Program, respectively). Note that EPA also removed future CAIR caps from its reference case for modeling the incremental impacts of CSAPR (EPA 2011b, pp. 30-32).

2. State Mercury Policies

Seventeen states have enacted policies to limit mercury emissions from coal units (EPA 2011c, pp. 3-8). These state mercury policies vary significantly in their form, stringency, and schedule. Some policies took effect as early as 2008, while others will take effect as late as 2017.

EIA incorporated these state mercury policies into *AEO 2011*, and we used the same inputs for our reference case. To comply with these state mercury policies, some coal units install mercury control technologies such as activated carbon injection (ACI) and fabric filters in the reference case. We allowed NEMS to determine the compliance measures at coal units based on parameters built into NEMS on mercury emission rates for different types of coal and different

---

[1] SO_2 emissions from power plants in Western states are regulated under the Acid Rain Program (EPA 2010a). We did not modify the SO_2 caps for Western power plants in NEMS for our reference case or policy case.

configurations of environmental control technologies, including scrubbers and SCR (EIA 2011b, p. 105-106).

Note that when NEMS determines based on its compliance calculations that coal units will install scrubbers, the scrubbers are assumed to be wet scrubbers (EIA 2011a, p. 46). Thus, reductions in mercury emissions from scrubbers that NEMS builds to comply with state mercury requirements reflect parameters for wet scrubbers. When NEMS calculates mercury emissions from coal units with existing or planned dry scrubbers, however, the mercury emissions accurately reflect parameters for dry scrubbers. Modeling issues related to wet and dry scrubbers are discussed further in the context of MACT HCl compliance below.

B. Cross-State Air Pollution Rule

EPA promulgated CSAPR as a replacement for CAIR in August 2011 (EPA 2011a). As noted above, CSAPR would cover a somewhat different set of Eastern states (27 in total) than CAIR but would also involve interstate cap-and-trade programs and would set the caps at similar levels to CAIR. CSAPR would set caps on emissions in each state but would allow interstate trade of emission allowances provided that state emissions stay within so-called variability limits. Covered units would not be able to use allowances from the Acid Rain Program, NO_x Budget Trading Program, or CAIR for compliance with CSAPR. The caps for both SO_2 and NO_x would become tighter over two phases. The SO_2 program would consist of Phase 1 (2012-2013) with a cap of 3.4 million tons and Phase 2 (2014 onward) with a cap of 2.1 million tons. The annual NO_x program would consist of Phase 1 (2012-2013) with a cap of 1.2 million tons and Phase 2 (2014 onward) with a cap of 1.1 million tons.

Table A-2 summarizes our compliance assumptions for CSAPR.

Table A-2. Compliance Assumptions for CSAPR

Policy	Emission	Compliance Assumptions
CSAPR	SO_2	Apply SO_2 caps (3.4 million tons in 2012-2013 and 2.1 million tons from 2014 onward) and allow NEMS to determine which units would need to install SO_2 control technologies or switch to lower-sulfur coal in the interstate cap-and-trade program (within state variability limits); in order to discourage unrealistic fuel switching in the model in 2012-2013, do not allow banking of CSAPR SO_2 allowances in those years
	NO_x	Apply NO_x caps (1.2 million tons in 2012-2013 and 1.1 million tons from 2014 onward) and allow NEMS to determine which units would need to install NO_x control technologies in the interstate cap-and-trade program (within state variability limits); allow banking of CSAPR NO_x allowances

Source: NERA assumptions as explained in text

1. CSAPR SO_2 Compliance

We modeled the CSAPR SO_2 program in NEMS as an interstate cap-and-trade program with state variability limits and two phases. We allowed NEMS to determine which units would install SO_2 control technologies and which would switch to lower-sulfur coal.

CSAPR modeling by EPA indicates substantial switching among various coals in 2012 and 2013 based on their sulfur content (EPA 2011b and NERA analysis of underlying data). Although EPA's modeling results seem reasonable for the total amounts of low-sulfur and ultra-low-sulfur coal, it may not be feasible to achieve the extent of fuel switching implied in EPA's modeling due to the prevalence of long-term fuel contracts, rail networks, and other real-world practicalities for coal units to switch their coal types on such a large scale in the early years of the program. Coal units appear to switch fuels in the early years in EPA's analysis to build up a large bank of CSAPR SO_2 allowances. To avoid what seems to be potentially unrealistic fuel switching in our modeling, we include fuel switching to meet the 2012 and 2013 caps but not to build up a bank of CSAPR SO_2 allowances in the early years of the program.

2. CSAPR NO_x Compliance

We modeled the CSAPR NO_x program in NEMS as an interstate cap-and-trade program with state variability limits and two phases. We allowed NEMS to determine which units would install various NO_x control technologies. Since fuel switching is not an issue for NO_x programs, we allowed banking of CSAPR NO_x allowances in all years.

C. Utility MACT

EPA proposed the Utility Maximum Achievable Control Technology (MACT) rule in May 2011 to reduce emissions of mercury and other hazardous air pollutants (including mercury, other hazardous metals, and acid gases) from coal- and oil-fired power plants across the country. The rule would set emission rate standards for different types of coal and oil based on maximum achievable control technology. The emission rate standards would apply to mercury, particulate matter (PM) as a proxy for all non-mercury hazardous metals, and hydrogen chloride (HCl) as a proxy for all acid gases. Covered power plants would have up to three years to comply with the rule, but permitting authorities could grant one-year extensions to power plants if they required additional time. Table A-3 shows the proposed emission rate standards for mercury, particulate matter, and hydrogen chloride from existing coal units under the Utility MACT rule.

Table A-3. Proposed Utility MACT Emission Rate Standards for Existing Coal Units

Coal Rank	Mercury	Hydrogen Chloride	Particulate Matter
Bituminous and subbituminous	1.2 lb/TBtu	0.0020 lb/MMBtu	0.030 lb/MMBtu
Lignite	4.0 lb/TBtu	0.0020 lb/MMBtu	0.030 lb/MMBtu

Notes: TBtu: trillion British thermal units of fuel input
MMBtu: million British thermal units of fuel input
The mercury standard for lignite shown in the table is the "beyond-the-floor" limit; the MACT standard based on the top 12 percent of units would be 11.0 lb/TBtu.
The mercury standard for bituminous and subbituminous coal is the update from the original value of 1.0 lb/TBtu based on EPA's letter of May 18, 2011 (EPA 2011e).
Source: EPA (2011d), p. 25027

Table A-4 summarizes our assumptions for MACT.

Table A-4. Compliance Assumptions for MACT

Policy	Emission	Compliance Assumptions
MACT	Mercury	Apply mercury standards in 2015 at all units and allow NEMS to determine which units would need to install ACI, fabric filters, and/or scrubbers
	HCl	Assign costs for DSI in 2015 at unscrubbed units smaller than 300 MW that consume subbituminous coal (these units requiring DSI will also require fabric filters); require dry scrubbers at all non-DSI units that consume Western bituminous coal, subbituminous coal, or lignite (these units requiring dry scrubbers will also require fabric filters); require wet scrubbers at all units that consume Eastern bituminous coal (these units requiring wet scrubbers will not require fabric filters, but NEMS may retrofit them with fabric filters for mercury or they may require fabric filters for MACT PM compliance)
	PM	In addition to requiring fabric filters at all units with DSI or dry scrubbers, and in addition to requiring fabric filters (in combination with ACI) at some units for MACT mercury compliance, require fabric filters for MACT PM compliance at the necessary number of coal units so that the same percentage of total U.S. coal capacity has fabric filters in 2015 as in the EPA MACT RIA; use EPA's list of coal units installing fabric filters from the MACT RIA to identify the additional coal units that would require fabric filters

Source: NERA assumptions as explained in text

1. MACT Mercury Compliance

As noted above in the context of state mercury policies for the reference case, NEMS estimates mercury emissions from coal units and can determine which units would install ACI, fabric filters, and/or scrubbers to comply with mercury reduction requirements. We required mercury reductions at all U.S. coal units based on the mercury standards in Table A-3. We assumed that compliance with the mercury standards would be required by 2015. Note that our inclusion of state mercury policies in the reference case dampens the impacts of the national MACT mercury standards in the policy case, because some coal units install ACI, fabric filters, and/or scrubbers anyway in the reference case to comply with the state mercury policies.

2. MACT HCl Compliance

NEMS does not model HCl emissions from coal units. Indeed, HCl emission rates from individual units can vary significantly over time as the unit burns coal from different mines and seams with different chlorine contents. Since NEMS does not model HCl emissions from coal units and thus cannot determine which controls would be required for compliance with HCl policies, we developed rules to assign HCl control technologies to individual units based on review of technology assumptions in EPA's regulatory impact analysis (RIA) for the MACT proposal (EPA 2011f) and other analyses, including comments on the MACT proposal submitted to EPA from various organizations (in Docket No. EPA-HQ-OAR-2009-0234). We assumed that compliance with the HCl standard would be required by 2015.

We assumed that every coal unit would require either dry sorbent injection (DSI), a dry scrubber, or a wet scrubber to comply with the HCl standard. Note that the variability in HCl emission rate at individual coal units over time would tend to cause owners to make relatively conservative assumptions about compliance measures so that they do not exceed the standard when the chlorine content of their coal happens to be high. DSI has significantly lower capital costs than a dry scrubber, which in turn has lower capital costs than a wet scrubber (EPA 2011c).[2] Since NEMS does not include DSI among its set of emission control technologies, we could not directly apply DSI to coal units in NEMS. Instead, we assigned costs to units requiring DSI to represent installation of DSI.

We assumed that DSI would be installed for HCl compliance at unscrubbed units smaller than 300 MW that consume subbituminous coal. The size limit for DSI is the same as the Bipartisan Policy Center's assumption for its analysis of potential EPA regulations (BPC 2011, p. 24); the Edison Electric Institute made a similar assumption for one of its modeling scenarios by limiting DSI to units smaller than 200 MW (EEI 2011, p. 4). We assumed that dry scrubbers would be installed for HCl compliance at all unscrubbed and non-DSI units that consume Western bituminous coal, subbituminous coal, or lignite. We further assumed wet scrubbers would be installed for HCl compliance at all unscrubbed units that consume Eastern bituminous coal. DSI and dry scrubber installations would also require fabric filters.

As noted above, NEMS assumes that all new scrubbers are wet scrubbers (EIA 2011a, p. 46). Scrubber cost inputs for the Retirement Model, however, accurately reflect whether the unit would need to install a wet scrubber or dry scrubber (or DSI). Moreover, we modified the unit-specific cost inputs in NEMS so that units needing to install wet scrubbers, dry scrubbers, or DSI had the appropriate costs.

---

2 Additional information on the costs of air emission control technologies appears at the end of this appendix.

3. MACT PM Compliance

NEMS does not model PM emissions from coal units and thus cannot determine which controls would be required for compliance with PM policies. The main control technologies for PM emissions are electrostatic precipitators (ESPs) and fabric filters (also called baghouses). NEMS includes fabric filters among its set of emission control technologies, but since NEMS does not model PM emissions, it only installs fabric filters on its own to reduce mercury emissions. We therefore developed rules to assign fabric filters to individual units based on reviews of technology assumptions in EPA's MACT RIA (EPA 2011f) and other analyses. We assumed that compliance with the PM standard would be required by 2015.

We assumed that most, but not all, coal units would require a fabric filter for PM compliance. Since NEMS installs fabric filters (in combination with ACI) on some coal units for compliance with state mercury policies and MACT mercury standards, these units would comply with the PM standard as well. We also required installation of fabric filters at units installing DSI or dry scrubbers for HCl compliance, and so these units too would comply with the PM standard. Thus, the only remaining coal units without fabric filters at this point are units with wet scrubbers (either existing wet scrubbers or new wet scrubbers for HCl compliance) and with sufficiently low mercury emission rates without fabric filters based on the NEMS parameters and determinations for mercury compliance. We reviewed EPA's MACT RIA data and assumed installation of fabric filters at the remaining coal units if they had fabric filters in the EPA data. The percentage of total U.S. coal capacity having fabric filters in our policy case is therefore approximately the same as the percentage in EPA's MACT RIA.[3]

Note that installing fabric filters at most U.S. coal units by 2015 is assumed to be feasible, despite the analysis by industry experts that such a large number of fabric filters could not be manufactured and installed in such a short period (UARG 2011).

D. Coal Combustion Residuals

EPA has considered several alternative forms of regulations in recent years for the disposal of coal combustion residuals (CCR), which include fly ash, bottom ash, boiler slag, and scrubber waste. The alternative forms of CCR regulations differ in their classification of CCR under Subtitles C or D of the Resource Conservation and Recovery Act (hazardous and non-hazardous, respectively) and compliance measures (for example, requiring liners at all surface impoundments or only at new surface impoundments). EPA proposed three alternative forms of CCR regulations in June 2010 (EPA 2010b). The unit-specific information in the RIA for this proposed rule, however, was based on a prior set of alternative forms that EPA developed in 2009 (EPA 2010c, p. 3).

Table A-5 summarizes our compliance assumptions for CCR regulations.

[3] EPA (2011f, pp. 8-18 and 8-14) gives the total U.S. coal capacity in 2015 in the MACT scenario as 299 GW, and 243 GW have fabric filters. Thus, 81 percent of total U.S. coal capacity in 2015 would have fabric filters in EPA's MACT scenario.

Table A-5. Compliance Assumptions for CCR Regulations

Policy	Compliance Assumptions
CCR	Assign costs to units in 2015 based on EPA Subtitle D in initial proposal

Source: NERA assumptions as explained in text

We modeled CCR compliance costs at coal units in 2015 based on EPA's unit-specific information for the initial form of CCR regulation under Subtitle D of the Resource Conservation and Recovery Act (EPA 2010c, Exhibit J3). As noted above, EPA only provided unit-specific information for the initial set of alternatives it developed in 2009; EPA did not provide unit-specific information for the final set of alternatives that it proposed in 2010. The initial form of CCR regulation under Subtitle D would lead to a cost of $30 billion (present value in 2009 dollars).[4] Note that this cost lies near the middle of the range of cost estimates for CCR regulation. For example, EPA (2010b, p. 10) gives the cost of the final form of Subtitle C regulation as $20 billion, and EPRI (2010, p. 4-3) gives the cost of Subtitle C regulation as between $55 billion and $77 billion.

We used this unit-specific cost information from EPA (2010c, Exhibit J3) as the basis for the potential costs of CCR regulation.

E. Section 316(b)

EPA proposed alternative forms of regulations for cooling water intake under Section 316(b) of the Clean Water Act in April 2011 (EPA 2011g). The regulations would affect the design of cooling water intake structures (to reduce impingement of aquatic organisms against intake structures) and the flow rates through cooling water systems (to reduce entrainment of aquatic organisms into cooling water systems) at power plants and other large facilities. The alternative forms of 316(b) regulations differ in their requirements for intake structures and flow rates, including possible use of best professional judgment for determining best technology available on a site-specific basis.

Table A-6 summarizes our compliance assumptions for 316(b) regulations.

Table A-6. Compliance Assumptions for 316(b) Regulations

Policy	Compliance Assumptions
316(b)	Assign costs to units in 2015 based on EPA Option 1 for impingement and 46 facilities installing cooling tower retrofits for entrainment

Source: NERA assumptions as explained in text

[4] EPA (2010b, Exhibit J3) gives the total annualized cost of the initial form of the Subtitle D alternative as $2.2 billion in 2009 dollars. EPA annualized these costs over 50 years. Using a real annual discount rate of 7 percent, this implies a present value of $30 billion.

We modeled 316(b) compliance costs for coal units in 2015 based on EPA information in the proposed rule related to Option 1, which includes a national requirement to reduce impingement, and an assumption that a total of 46 facilities would install cooling towers for entrainment under site-specific determinations. EPA (2011g, p. 22219) shows that Option 1 would lead to costs of $5 billion (present value in 2009 dollars) for electric generators to reduce impingement.[5] We estimated the apportionment of these costs across generation units, including coal units as well as natural gas, oil, and nuclear units, based on unit-specific cooling water intake data from EIA Form 860 (EIA 2011c).

EPA (2011g, p. 22211) noted that if the 46 fossil units with the largest cooling water withdrawals from tidal waters installed cooling towers to reduce entrainment, their total cost would be $7 billion.[6] Note that of the two hypothetical cooling tower scenarios for which EPA provided information, this scenario involved fewer facilities and lower total costs. We identified the 46 fossil units with the largest cooling water intake withdrawals from tidal waters using EIA Form 860 (EIA 2011c) and apportioned costs to individual units based on their intake data.

We used this unit-specific cost information based on EPA (2011g) as the basis for our modeling of the potential costs of 316(b) regulation.

F. Cost Assumptions for Air Emission Control Technologies

As discussed above, we relied on unit-specific inputs in NEMS for information about coal units for modeling retirements and energy market impacts. We modified the potential costs of air emission control technologies in NEMS to base them on EPA (2011c).

Table A-7 shows EPA and EIA assumptions for the costs of air emissions controls. These cost estimates include energy penalties for net capacity and heat rate due to some of the controls. Some types of costs show economies of scale (i.e., unit costs per kW are smaller for large units than small units), but other types of costs are uniform for all sizes of units. We used these cost assumptions from EPA in our modeling.

Note that the sudden large increase in demand for control technologies and skilled construction workers implied by our technology assumptions may not be feasible within the limited time assumed in our study and, in any event, the increased demand could drive up prices for control technologies. We did not develop any estimates of this "gold rush" effect. We assumed that the retrofits would be feasible on such a large scale and that there would be no price inflation due to the sudden increase in demand.

---

5 EPA (2011g, p. 22219) gives the total annualized cost of Option 1 for electric generators as $386 million in 2009 dollars. EPA annualized these costs over 50 years. Using a real annual discount rate of 7 percent, this implies a present value of $5 billion.

6 EPA (2011g, p. 22211) gives the total annualized cost of the 46 facilities installing cooling towers as $480 million in 2009 dollars. EPA annualized these costs over 50 years. Using a real annual discount rate of 7 percent, this implies a present value of $7 billion.

Table A-7. Air Emission Control Costs

	100 MW		300 MW		500 MW	
	EPA	EIA	EPA	EIA	EPA	EIA
Wet Scrubber						
Capital (2010$/kW)	$850	$762	$622	$580	$538	$485
Fixed O&M (2010$/kW-year)	$24.40	$24.99	$11.20	$24.99	$8.35	$24.99
Variable O&M (2010$/MWh)	$2.11	$0.44	$2.11	$0.44	$2.11	$0.44
Capacity Penalty	-1.84%	-5.00%	-1.84%	-5.00%	-1.84%	-5.00%
Heat Rate Penalty	1.87%	5.26%	1.87%	5.26%	1.87%	5.26%
Dry Scrubber						
Capital (2010$/kW)	$727	-	$532	-	$460	-
Fixed O&M (2010$/kW-year)	$17.71	-	$8.86	-	$6.76	-
Variable O&M (2010$/MWh)	$2.70	-	$2.70	-	$2.70	-
Capacity Penalty	-1.45%	-	-1.45%	-	-1.45%	-
Heat Rate Penalty	1.47%	-	1.47%	-	1.47%	-
SCR						
Capital (2010$/kW)	$268	$225	$217	$184	$201	$165
Fixed O&M (2010$/kW-year)	$2.60	$2.25	$0.83	$1.88	$0.73	$1.66
Variable O&M (2010$/MWh)	$1.38	$0.34	$1.38	$0.34	$1.38	$0.34
Capacity Penalty	-0.58%	0.00%	-0.58%	0.00%	-0.58%	0.00%
Heat Rate Penalty	0.59%	0.00%	0.59%	0.00%	0.59%	0.00%
ACI						
Capital (2010$/kW)	$30	$6	$12	$6	$8	$6
Fixed O&M (2010$/kW-year)	$0.12	$1.71	$0.05	$1.71	$0.03	$1.71
Variable O&M (2010$/MWh)	$0.52	$0.26	$0.56	$0.26	$0.60	$0.26
Capacity Penalty	-0.06%	0.00%	-0.06%	0.00%	-0.06%	0.00%
Heat Rate Penalty	0.06%	0.00%	0.06%	0.00%	0.06%	0.00%
Fabric Filter						
Capital (2010$/kW)	$230	$78	$187	$78	$170	$78
Fixed O&M (2010$/kW-year)	$0.94	$5.97	$0.83	$5.97	$0.73	$5.97
Variable O&M (2010$/MWh)	$0.16	$0.00	$0.16	$0.00	$0.16	$0.00
Capacity Penalty	-0.60%	0.00%	-0.60%	0.00%	-0.60%	0.00%
Heat Rate Penalty	0.60%	0.00%	0.60%	0.00%	0.60%	0.00%
DSI						
Capital (2010$/kW)	$134	-	$61	-	$43	-
Fixed O&M (2010$/kW-year)	$2.39	-	$0.94	-	$0.61	-
Variable O&M (2010$/MWh)	$7.70	-	$7.70	-	$7.70	-
Capacity Penalty	-0.79%	-	-0.79%	-	-0.79%	-
Heat Rate Penalty	0.79%	-	0.79%	-	0.79%	-

Note: "-" denotes that NEMS does not model the control technology.
Source: EPA (2011c) and NEMS inputs

G. References

Bipartisan Policy Center. 2011. *Environmental Regulation and Electric System Reliability.* Washington, D.C.: BPC, June. (www.bipartisanpolicy.org/sites/default/files/-BPC%20Electric%20System%20Reliability.pdf, accessed September 20, 2011)

Edison Electric Institute. 2011. *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet.* Prepared by ICF International. Washington, D.C.: EEI, January (www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_

Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf, accessed September 20, 2011)

Electric Power Research Institute. 2010. *Cost Analysis of Proposed National Regulation of Coal Combustion Residuals from the Electric Generating Industry.* Palo Alto, CA: EPRI, November.

U.S. Court of Appeals for the D.C. Circuit. 2008. *North Carolina v. EPA.* 550 F.3d 1176, 1178. Case 05-1244. Washington, D.C.: U.S. Court of Appeals for the D.C. Circuit, December 23. (www.epa.gov/airmarkets/progsregs/cair/docs/CAIRRemandOrder.pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011a. *Annual Energy Outlook 2011.* Washington, D.C.: EIA, April. (www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011b. *Assumptions to the Annual Energy Outlook 2011.* Washington, D.C.: EIA, July. (www.eia.gov/forecasts/aeo/assumptions/pdf/-0554(2011).pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011c. "Form 860 Data Files." www.eia.gov/cneaf/electricity/page/eia860.html, accessed September 20, 2011

U.S. Environmental Protection Agency. 2005. "Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_x SIP Call; Final Rule." 70 *Federal Register* 25162-25405. Washington, D.C.: EPA, May 12. (edocket.access.gpo.gov/2005/pdf/05-5723.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2010a. *Acid Rain and Related Programs: 2009 Highlights.* Washington, D.C.: EPA, December. (www.epa.gov/airmarkets/progress/ARP09_downloads/ARP_2009_Highlights.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2010b. "Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities; Proposed Rule." 75 *Federal Register* 35128-35264. Washington, D.C.: EPA, June 21. (http://www.regulations.gov/#!documentDetail;-D=EPA-HQ-RCRA-2009-0640-0352, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2010c. *Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues Generated by the Electric Utility Industry: Appendix.* Washington, D.C.: EPA, April 30. (www.regulations.gov/-#!documentDetail;D=EPA-HQ-RCRA-2009-0640-0003, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011a. "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals." 76 *Federal Register* 48208-48483. Washington, D.C.: EPA, August 8. (www.gpo.gov/fdsys/pkg/FR-2011-08-08/pdf/2011-17600.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011b. *Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States*. Washington, D.C.: EPA, June. (www.epa.gov/airtransport/pdfs/FinalRIA.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011c. *Documentation Supplement for EPA Base Case v4.10_PTox — Updates for Proposed Toxics Rule*. Washington, D.C.: EPA, March. (www.epa.gov/airmarkets/progsregs/epa-ipm/docs/suppdoc.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011d. "National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Proposed Rule." 76 *Federal Register* 24976. Washington, D.C.: EPA, May 3. (www.gpo.gov/fdsys/pkg/FR-2011-05-03/pdf/2011-7237.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011e. Letter from Gina McCarthy to Lee B. Zeugin. May 18. (www.4cleanair.org/Documents/EPAResponsetoLZeugin.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011f. *Regulatory Impact Analysis of the Proposed Toxics Rule*. Washington, D.C.: EPA, March. (http://www.epa.gov/ttnecas1/-regdata/RIAs/ToxicsRuleRIA.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011g. "National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities; Proposed Rule." 76 *Federal Register* 22174-22288. Washington, D.C.: EPA, April 20. (www.gpo.gov/fdsys/pkg/FR-2011-04-20/pdf/2011-8033.pdf, accessed September 20, 2011)

Utility Air Regulatory Group. 2011. *Feasibility of Retrofitting Fabric Filter Particulate Matter Control Technology to the Electric Generating Unit Inventory As Projected by EPA*. Report prepared by J. Edward Cichanowicz, Michael Hein, James Marchetti, and Walter Piulle. Washington, D.C.: UARG, August 4. (www.regulations.gov/#!documentDetail;-D=EPA-HQ-OAR-2009-0234-17785, accessed September 20, 2011)

Appendix B: Coal Unit Retirement Model

NERA has developed a retirement model to estimate the possible coal unit retirements due to the potential costs of EPA regulations. The model uses Monte Carlo uncertainty analysis to simulate the decision facing coal unit owners on whether to incur the costs to comply with additional future environmental requirements (and other future costs) or to retire the unit.

The sections below are organized as follows: Section A describes the main decision module, and Section B describes the sub-modules that generate the specific estimates used to run the Monte Carlo simulations in the main decision module.

A. Retirement Decision Module

The owner of each coal unit is presumed to base its decision on whether or not to retire the unit by comparing the future costs for the unit—taking into account potential additional environmental compliance costs as well as other costs—to the future costs of the likely alternative generation. The retirement decision module calculates the expected net present value (NPV) of costs for existing coal units as well as the NPV of costs for the likely alternative. Based upon likely future fuel market conditions, the alternative unit for comparison is assumed to be a combined cycle gas turbine (CCGT) unit. The cost calculations for coal and gas are done separately, but correlations in variables subject to uncertainty are taken into account. All retrofit costs are assumed to be incurred in 2015.

1. Net Present Value of Costs for Existing Coal Units

The NPV of costs for existing coal unit i is given by the following expression:

Equation 1. NPV of existing coal costs

$$d_{ir}R_i + \sum_{t=1}^{T_i} d_{it}(C_{it} + O_{it} + E_{it})$$

Where:

- R_i is the capital cost of retrofits. The total cost of retrofits for a given plant depends on the plant's current configuration, the randomly drawn retrofit costs for that plant from the retrofit/construction cost module, and what regulatory requirements the plant has in the regulatory scenario of interest. The cost of retrofits is then just the sum of the costs for each individual retrofit technology required at the plant.

- d_{ir} is the discount rate for unit i in year r, where r is the year in which retrofits take place. It is given by:

$$\left(\frac{1}{1+r}\right)^{t-1}$$

where t indicates time in years, where the first year in the model is t=1. The discount rate for a given unit depends on whether the utility that owns the unit is private or public. Following the NEMS model, we take the mean of the (real) discount rate to be 7 percent for units owned by public power organizations (e.g., the Tennessee Valley Authority and rural electric cooperatives) and 11.8 percent for units owned by private (investor-owned) companies, including units owned by regulated utilities with private (investor-owned) parent companies.

- d_{it} is the discount rate for unit i in year t, defined as above for d_{ir}.
- T_i is the remaining lifetime of unit i in years.
- C_{it} is the cost of coal for unit i in year t. The cost of coal is calculated by the hourly operation module when run decisions are calculated. It is essentially the average cost of coal across all operating hours weighted by the capacity factor at each hour. These plant-specific costs are developed as described in the coal cost module section. For the small number of plants with missing coal costs, average regional costs are used. If a retrofit increases the plant heat rate it will increase coal costs.
- O_{it} is the operating and maintenance (O&M) cost for unit i in year t. This is calculated as the sum of variable O&M and fixed O&M. Some retrofits result in additional O&M costs; where this is the case, variable O&M and/or fixed O&M are increased accordingly. We use EPA's O&M cost assumptions from the MACT analysis. Variable O&M costs for a year are calculated as the sum of hourly variable O&M costs. If we take V_{ih} to be the variable O&M costs for unit i in hour h (in dollars per megawatt-hour), then V_{it}, the variable O&M costs for unit i in year t, are given by:
  $$\sum_{h=1}^{8760} TC_i(L_{ih} : V_{ih})$$
  where TC_i is the total capacity for plant i and L_{ih} is the capacity factor for plant i in hour h.
- E_{it} is the cost of system energy for unit i in year t necessary to compensate for capacity factors less than one at any hour. In order to make an appropriate comparison between existing coal and new gas, the costs of both gas and coal in our model are calculated as the costs to generate TC_i times 8760 energy per year. This assures that the retirement decision accounts for differences in the capacity factors of new and existing units. Thus, included in the calculation of the costs of existing coal is the cost of system energy necessary to compensate for capacity factors less than one at any hour. E_{it} is calculated as:
  $$PM_{it} \cdot PE_{it} \cdot G_{it}$$
  Here, G_{it} is the generation by unit i in year t, PM_{it} is the ratio of the weighted average system energy cost to the overall average electricity price across all simulation draws at the power hub to which plant i is assigned ($WASC_{ijt}/ASEC_{it}$), and PE_{it} is the average marginal cost of energy in the NERC region to which i belongs in year t (from the NEMS model outputs). The value of G_{it} is an output of the hourly operation module and is calculated as:
  $$G_{it} = \sum_{h=1}^{8760} TC_i(L_{ih})$$
  The weighted average system energy cost is calculated as:

$$WASC_{ijt} = \frac{\sum_{h=1}^{8760}(1 - L_{ijh})P_{ijh}}{\sum_{h=1}^{8760} L_{ijh}}$$

whereas the overall average system energy cost is:

$$ASEC_{it} = \frac{1}{8760} \cdot \frac{1}{100} \cdot \sum_{j=1}^{100} \sum_{h=1}^{8760} P_{ijh}$$

where P_h is the marginal cost of energy at hour h from the electricity price module. Thus, the factor of $PM_{it} \cdot PE_{it}$ in the calculation of E_{it} serves to calibrate the outputs of the electricity price and hourly operation modules to NEMS electricity prices and map the five power hubs to the twenty-two NERC regions.

2. Net Present Value of Costs for Potential Alternative Unit (New CCGT)

The NPV of costs for replacing existing coal unit i with new CCGT of equal capacity is calculated as:

Equation 2. NPV of replacement CCGT costs

$$\sum_{t=1}^{T_i} d_{it}(CG_{it} + OG_{it} + EG_{it} + ON_{it})$$

Where d_{it} and T_i are identical to that for existing coal, and:

- CG_{it} is the average delivered cost of gas for the region in which unit i is located in year t using the appropriate capacity factor and heat rate.
- OG_{it} is the total O&M costs in year t for a CCGT constructed to replace unit i. This incorporates both fixed and variable O&M costs. The variable O&M costs are a function of the hourly capacity factors for a new CCGT in year t. These capacity factors are modeled based on the predicted operation of a sample of recently constructed CCGTs in each region and are an output of the hourly operation module. Thus, there are actually several calculations of replacement CCGT costs to compare to each coal plant, one for each CCGT in the sample of recently constructed CCGTs in each region.
- EG_{it} is the cost of grid energy to bring total generation to TC_i times 8760. This is calculated in the same way as the cost of grid energy for coal plants.
- ON_{it} is the equivalent annual overnight capital cost payment in year t for a CCGT replacement for plant i. The overnight costs are always annualized over the entire lifetime of the gas plant (30 years, consistent with the NEMS model), and are based on the sampled CCGT overnight costs drawn in the retrofit/construction cost module. However, since T_i may be less than 30 (and the modeling horizon only encompasses 25 years), the entire capital cost of the plant is not reflected in this calculation. This avoids inappropriately overstating the equivalent annual cost of a CCGT plant built to replace an existing coal plant.

3. Monte Carlo Retirement Decision Calculation

The NPV of costs for existing coal and for replacement CCGT are compared in each of the 100 simulation draws used in the Monte Carlo formulation. The costs for CCGT are based on the minimum of costs calculated using the sampled recently constructed CCGTs in each region as the basis for hourly operation of a new CCGT. Since a new CCGT would be at least as efficient as any existing CCGTs, this calculation is conservative (in the sense that it might overstate the future costs of a future CCGT and thus understate the likelihood of retirement).

The owner is presumed to retire the coal unit based upon a comparison of the NPV of the costs of the coal unit and the costs of the replacement CCGT plant. In particular, the retirement decision sub-module calculates the difference in costs for each of the 100 equally-likely Monte Carlo draws. The coal unit is presumed to retire if the expected value of this cost difference is positive, i.e., the coal unit is expected to be more expensive than the replacement natural gas unit.

B. Individual Cost Component Sub-Modules.

The Retirement Model includes separate sub-modules to model the various elements that influence the cost of continuing to operate an existing coal unit and the cost of replacing the exiting coal unit with a new combined cycle gas turbine (CCGT) unit. The methodology in each sub-module for energy prices results in mean values based upon the NEMS model using AEO 2011, with the sub-modules focusing on developing estimates of the potential alternative price paths. These sub-modules are summarized and described below.

1. *Natural gas price simulation sub-module.* This sub-module simulates possible future natural gas price paths. The formulation assumes that future natural gas prices can be modeled as an autoregressive process.

2. *Coal price sub-module.* This sub-module models regional coal prices. The formulation assumes that future coal prices can be modeled as a vector autoregression (VAR) process. Coal prices in several regions are modeled as dependent time series.

3. *Electricity price sub-module.* This sub-module models hourly electricity prices. The empirical formulations are based upon data from five major trading hubs across the United States.

4. *Hourly power plant operation sub-module.* This sub-module models the hourly operation of existing coal plants greater than 25 megawatts (MW) capacity. The sub-module also models operation of CCGT units in each region on the basis of recently constructed units.

5. *Retrofit and construction costs sub-module.* This sub-module models retrofit costs for emission control technologies and construction costs for new CCGT units as random variables, with the construction parameters assumed to be correlated. (Costs for the same type of control at different plants are assumed to be more highly correlated than costs for different controls and for controls and new construction costs.) The parameters for the model are taken from EPA cost assumptions for the MACT analysis and recent engineering reports.

The following sections provide additional information on these sub-modules.

1. Natural Gas Price Simulation Sub-Module

The natural gas price module models natural gas prices as an autoregressive process of order one (AR-1 process). The model for price at time *t* is:

Equation 3. Natural gas price model

$$\log(p_t) = \alpha + \gamma \log(p_{t-1}) + \varepsilon_t, \quad \varepsilon_t \sim N(0,\sigma^2)$$

The parameters of the model are a constant term (α), an autoregressive term (γ), and a random error term (ε_t), which is assumed to be normally distributed with zero mean and unknown variance (σ^2). The parameters are estimated from daily Henry Hub price data for the years 2005-2010. The estimated value of the autoregressive term is less than one, and therefore the model for gas price is mean-reverting.

Using the estimated parameter values, we then simulate 100 future daily natural gas price paths from 2011-2035 for use in the model. Simulation is relatively simple: starting from the last day's price in the historical data, simulate the first day of the forecast series by taking the log of the previous day's price, multiplying by the estimated value of γ, adding the estimated value of α, and adding a value drawn from $N(0,\sigma^2)$. This is repeated for the second day of the forecast using the simulated value from the first day, and so on until prices have been simulated through the end of 2035. This entire process is then repeated 100 times to give 100 daily price paths through 2035.

As noted above, we adjust the simulated natural gas price paths such that the expected gas price in each year matched the EIA forecast. The expression for the price at time *t* in our model is given by:

Equation 4. Expression for price in the natural gas model

$$p_t = \exp(\alpha + \varepsilon_t) p_{t-1}^{\gamma}$$

From this we have that the expression for the expected price at time *t*, given the price in the previous period, is:

Equatiou 5. Expression for expected value of price in period *t* given price in period *t-1*.

$$E(p_t \mid p_{t-1}) = \exp\left(\alpha + \sigma^2/2\right) p_{t-1}^{\gamma}$$

From this expression it is clear that any constant *C* added to the right hand side of the original log-log form of the model will result in the conditional expectation of p_t being multiplied by exp(*C*). Thus, we simulate many price paths and take the mean price in each year (which is a consistent estimator of the expectation of price in any year). We then add a constant C_y to the right hand side of Equation 3 for every day in year *y* such that the expected price in year *y* matches the NEMS price in year y. We then simulate 100 price paths from this calibrated form of the model.

2. Coal Price Sub-Module

The variability in coal prices is modeled using information for the two main coal contracts for bituminous and sub-bituminous coal (Central Appalachian/Big Sandy and Powder River Basin (PRB), respectively) using a vector autoregression (VAR). (Lignite coal variability is assumed to be the same as sub-bituminous.) The model assumes that coal prices are a stochastic process and that prices in the two regions are related. The mathematical form of the model is:

Equation 6. Coal price model

$$Y_t = c + AY_{t-1} + \varepsilon_t, \quad \varepsilon_t \sim N_2(0, \Sigma)$$

Where Y_t is a 2x1 vector of prices (the Appalachian and PRB prices at time t), A is a linear transformation of the lagged price Y_{t-1}, c is a 2x1 vector of constants, and ε_t is a bivariate normal random variable with a 2x1 mean vector of zeroes and covariance matrix Σ. We use historical weekly coal price data from 2005-2010 to estimate the parameters of the model (c, A, and Σ).

We then simulate from this model 100 weekly price paths for 2011-2035 for PRB and Appalachian coal. As noted, the modeling assures that the mean prices are equal to those predicted in NEMS; we calculate the ratio of the average price in each year for each of the two coal contracts in our forecast to the average price from 2005-2010. We then add constants to the expression in equation 4 to make the ratios of the annual average price to the 2005-2010 average the same as the ratio of the annual mine mouth prices for bituminous and subbituminous coal in NEMS to the average prices for those coals from 2005-2010. Thus, the VAR model gives us the dependence structure and uncertainty in coal prices, whereas NEMS provides the means.

We then take a two-year moving average of the simulated coal prices in each of the 100 simulations and then take the ratio of this moving average to the overall average coal price for each year (across all simulations). We use the plant-specific average fuel costs from EIA 423 for 2005-2010 and multiply them by the ratio of the moving average from each of the 100 simulations to the overall moving average to get plant-specific coal prices for each week in the model. We use a long-term moving average to reflect that most coal prices for electric utilities are set by long-term contracts and an analysis of historical market prices compared to historical coal costs for electric utilities showed that a two-year moving average was a good predictor of relative coal price movements.

A small number of plants are missing cost data for delivered coal in EIA 423. We impute costs for delivered coal based on the quantity and type of coal delivered to each plant using an inverse-distance weighted average of the costs of the same type of coal delivered to nearby plants. We verified that the historical average delivered prices for the 22 NERC regions in the NEMS model calculated from EIA 423 (and using the above methodology to fill in missing prices) were very similar to NEMS average prices for the years 2005-2010 for those regions. The EIA data provides monthly coal costs; for consistency with the run decision model, we linearly interpolate between the monthly costs to obtain daily coal costs.

3. Electricity Price Sub-Module

The variability in hourly electricity prices is modeled using data for five hubs throughout the United States (ERCOT, PJM, Cinergy, SP15, and NYISO). Electricity prices are taken to be a function of the previous hour's electricity price, natural gas prices (with the magnitude of the effect varying with the hour), hour of day, season, whether the day is a weekend day or a weekday, and an innovation (error) term. The innovations are normal with zero mean and stochastic, time-varying variance. The mathematical specification is an exponential GARCH (EGARCH) model and is given by the following set of equations:

Equation 7. Electricity price model

$$\log(p_t) = X_t\beta + \alpha \log(p_{t-1}) + \varepsilon_t$$
$$\varepsilon_t = \sigma_t z_t \quad z_t \sim N(0,1)$$
$$\log(\sigma_t^2) = \omega + \gamma_g g(Z_{t-1}) + \gamma_s \log(\sigma_{t-1}^2)$$
$$g(Z_t) = \theta Z_t + \lambda(|Z_t| - E(|Z_t|))$$

Where p_t is the price at time t, and X is a matrix of covariates. The structure of the model allows the sign and magnitude of the standard normal random variable Z_t to affect volatility (σ^2) separately. The model also allows for heteroskedasticity (through the dependence of σ_t^2 on σ_{t-1}^2) and volatility clustering (periods of large price swings and periods of relative calm).

The covariates in the mean regression (the matrix X_t) include dummy variables for hour of day, hour of day dummies interacted with natural gas prices, seasonal dummies, and weekday/weekend dummies. The model parameters are estimated on historical electricity price data for the five electricity price hubs for 2005-2010. We then simulate electricity price series for each of the five hubs from the model, using as inputs the simulated natural gas prices from the natural gas price model. We simulate 100 realizations of hourly prices for 2011-2015.

4. Hourly Power Plant Operation Sub-Module

The hourly power plant operation module models power plant hourly run decisions and output as a function of price and marginal costs. The relevant price variability in the model is determined by matching each power plant to one of the five regional hubs. As noted, the mean electricity prices are based upon NEMS AEO 2011.

The decision of whether to operate is modeled as a logistic regression:

Equation 8. Run decision model

$$r_t \sim bernoulli(p_t)$$
$$p_t = \Pr(r_t = 1) = \frac{e^{X_t\beta}}{1 + e^{X_t\beta}}$$

Where $r_t = 1$ indicates that the plant decides to run at time t. Here X_t is a vector of covariates, which in this case are constant, the hourly electricity price, and negative one times the sum of fuel costs and allowance costs per MWh for the plant at each hour. In the case of CCGT plants, the implied heat rate (ratio of the electricity price to the gas price) is used in place of the electricity price less costs.

Conditional on operating, we then model the capacity factor (output divided by capacity) as a mixture of linear regression models. In this model, each unit can operate in up to five distinct "modes," and the choice of "mode" is a function of the electricity price less costs (or, in the case of CCGT, the implied heat rate) and a constant specific to each mode. Conditional on choosing a "mode," the capacity factor is modeled as normally distributed with mean and variance estimated from the data. The mathematical representation of the model is:

Equation 9. Capacity factor model

$$m_t \mid r_t = 1 \sim multinomial(1, s_t)$$

$$s_{jt} = \Pr(m_t = j \mid r_t = 1) = \frac{e^{X_t \beta_j}}{\sum_{i \neq j} e^{X_t \beta_i}} \quad \beta_1 = \vec{0}$$

$$L_t \mid m_t = j, r_t = 1 \sim N(\mu, \sigma^2)$$

Where m_t is the operating mode at time t (m_t=1,...,5), s_t is a simplex vector (vector whose components add to one, making them plausible as probabilities for different alternatives), X_t is a matrix of covariates (here covariates are the electricity price less costs for coal plants or implied heat rate for CCGT and a dummy for the operating "mode" alternative), L_t is the capacity factor at time t and μ and σ^2 are the mean and variance of a normal distribution. The choice of this form for the model was based on the observation that power plant capacity factors exhibit multimodality, whereas electricity prices, the main factor in power plant operation decisions, do not. Thus, some type of model allowing for flexible multimodality was necessary, and the mixture of normal models is one such model that has well-established estimation techniques available.

We estimate the model on historical hourly power plant operation data for coal plants and a sample of recently constructed CCGTs for the years 2005-2010. The model predicts the historical capacity factors very accurately, with virtually all of the variance in the historical data explained by the model. We then simulate power plant operation for coal plants and sampled CCGTs using the simulated electricity, coal, and gas prices from the electricity and gas price modules for the years 2011-2035, as well as estimates of incremental variable cost of new controls, expected allowance prices, and heat rate penalties of new controls as factors affecting coal plant marginal costs. The result is 100 sets of hourly plant operation patterns for every plant in the dataset.

5. Retrofit Costs and Construction Costs Sub-Module

This sub-module develops information on the variability in technology retrofit costs as well as CCGT construction costs, which are assumed to be correlated in our model. We model the variability in costs for the relevant control technologies (wet and dry scrubbers, dry sorbent injection, fabric filters, activated carbon injection, closed cycle cooling, and coal combustion residual compliance costs) and for new CCGTs. The correlations include those for different technologies and the same plant, for the same technology across plants, and for retrofit costs and new construction costs. The vector of all control costs is modeled as multivariate lognormal, mathematically represented as:

Equation 10. Retrofit/control costs model

$$r \sim N(\mu, \Sigma)$$

$$c = e^{r}$$

Where r is a multivariate normal random variable with mean vector μ and covariance matrix Σ, and c is the control/construction cost vector (a vector containing all control/construction costs for all plants). There exists a closed-form expression for the expected value of c as a function of μ. We take the EPA's control costs estimates for different control types and EIA's overnight costs for CCGT as the expected value of c, and back solve for the mean vector μ. No suitable data exists to estimate the covariance matrix Σ. Thus, we create a covariance matrix from a correlation matrix with the following assumed structure. We assume that the correlation between costs for the same control at different plants is 0.6 and the correlation between costs for different controls at different plants is 0.4. We assume that the correlation between costs for all environmental controls and the capital cost of a new CCGT is 0.4. Thus, we assume that costs for the same type of control will be more highly correlated than costs for different types of controls.

In order to create a covariance matrix from this correlation matrix, we also must define a variance vector for the control/construction costs (a vector containing the variances for each control type/plant combination and for CCGT retrofit costs). As described previously for the mean vector, there is a closed-form expression for the variance vector of the normal distribution in terms of the variance vector of the lognormal distribution. Variances are based on the uncertainty ranges given in the Raytheon Coal Unit Environmental Cost Model documentation (which is used by EIA to estimate plant retrofit costs in the NEMS model). In the Raytheon documentation, retrofit costs estimates are given with an uncertainty of ±30%. We assume that standard deviations of the lognormal cost distributions are 15% of the cost, or half of the uncertainty range given by the Raytheon report.

The model takes 100 separate draws of retrofit/construction costs from the multivariate lognormal distribution defined above. The joint variability in costs for retrofits and for new CCGT construction is then used in the retirement decision sub-module, as discussed above.

Appendix C: Energy Market Modeling

This appendix provides details on the National Energy Modeling System (NEMS) as well as our data and methodology for using NEMS to model the potential energy market impacts of the four EPA regulations. This appendix also shows key energy market impact results from NEMS for each year between 2012 and 2020.

A. National Energy Modeling System

This section provides an overview of NEMS and its input categories related to emission controls.

1. Overview

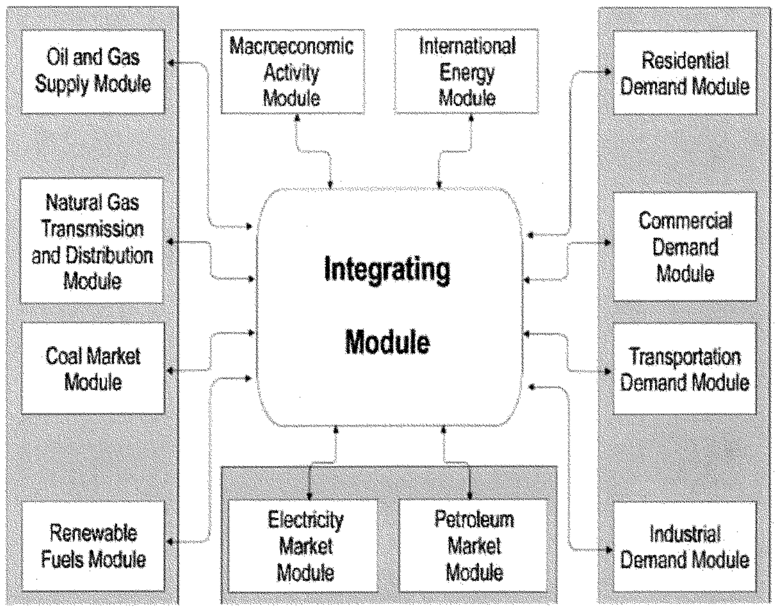
The U.S. Energy Information Administration (EIA) developed and maintains NEMS to produce projections of energy prices and quantities in the long term. EIA also uses NEMS to perform policy analyses in response to requests from Congress, the White House, the Department of Energy, and other government agencies. EIA prepares an *Annual Energy Outlook* (*AEO*) with long-term projections of energy prices and quantities based on current policies and various assumptions. As discussed in Appendix A, our modeling of the potential energy market impacts of the four EPA regulations with NEMS is based on inputs for *AEO 2011* (EIA 2011a); its assumptions are summarized in EIA (2011b).

Figure C-1 shows the thirteen modules in NEMS and their linkages. All modules interact via the Integrating Module at the center of the figure. The four modules to the left in the figure (Oil and Gas Supply, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels) relate to the supply of primary energy sources. The four modules to the right in the figure (Residential Demand, Commercial Demand, Transportation Demand, and Industrial Demand) relate to the demand for energy. The two modules to the bottom of the figure (Electricity Market and Petroleum Market) convert primary energy sources into electricity and petroleum products. Finally, the two modules to the top of the figure (Macroeconomic Activity and International Energy) provide information from outside U.S. energy systems.

NEMS uses the thirteen modules shown in Figure C-1 to balance energy supply and demand in each region of the United States. In particular, the model calculates the least-cost way to satisfy demand in each region based on the costs of alternative forms of energy and various constraints, including resource availability and energy transportation infrastructure. The level of regional detail in NEMS varies for different forms of energy. For example, NEMS divides the United States into 22 electricity markets, 13 coal production regions, and nine natural gas production regions. Regional detail for energy demand is based on the nine Census divisions.

Additional detail on energy market modeling and NEMS can be found in EIA (2009) and EIA (2011b).

Figure C-1. Overview of NEMS



Source: EIA (2011b, p. 4)

2. Input Categories Related to Emission Controls

NEMS input files include a database of all generation units in the United States as well as parameters that apply uniformly to all units within certain categories. The database includes current and planned scrubber, SCR, and particulate controls for each coal unit in the United States. The database also includes information on some types of environmental control costs for each coal unit. Other types of environmental control costs enter NEMS as parameters that apply uniformly to the relevant coal units.

Table C-1 summarizes unit-specific and uniform inputs related to emission controls. Note that direct sorbent injection (DSI) is not included as an emission control in NEMS, as discussed in Appendix A.

Table C-1. NEMS Inputs Related to Emission Controls

	Miscellaneous	Scrubbers	SCR	ACI	FF	DSI
Unit-specific inputs	- Construction date - Retirement date - Capacity - Capacity factor (historical) - Heat rate - Baseline fixed O&M cost (excluding controls) - Baseline variable O&M cost (excluding controls) - Baseline annual capital cost (excluding controls)	- Current or planned configuration - Capital cost ($/kW) - Emission reduction percentage	- Current or planned configuration - Capital cost ($/kW) - Additional fixed O&M cost - Additional variable O&M cost - Emission reduction percentage	- Current or planned configuration - Emission reduction percentage (based on other controls and coal type)	- Current or planned configuration - Emission reduction percentage (based on other controls and coal type)	- Not in NEMS
Uniform inputs for all coal units		- Capacity penalty - Heat rate penalty - Additional fixed O&M cost - Additional variable O&M cost		- Capital cost ($/kW) - Additional fixed O&M cost - Additional variable O&M cost	- Capital cost ($/kW) - Additional fixed O&M cost	- Not in NEMS

Source: NERA review of NEMS inputs

3. Input Categories Related to CCR and 316(b)

NEMS does not model compliance with CCR or 316(b) policies. As discussed further below, we modeled these policies in NEMS by adding their costs to the unit-specific inputs for general capital costs.

B. Methodology

This section describes NEMS inputs and outputs for modeling the potential energy market impacts of the four EPA regulations.

1. NEMS Inputs

We entered three types of modeling inputs into NEMS: (1) potential emission control costs; (2) coal unit retirements; and (3) compliance measures. This section describes each of these types of inputs.

a. Emission Control Costs

As described in Appendix A, we used EPA estimates for potential emission control costs rather than the EIA assumptions built into NEMS. As summarized above in Table C-1, NEMS incorporates data on the potential costs of environmental controls in case installation of such controls is required. We modified these emission control costs in NEMS for both the reference case and policy case so that costs would consistently reflect EPA cost estimates in both cases. For example, the reference case includes state mercury regulations that would cause some coal units to install ACI and fabric filters. The costs of these ACI and fabric filter retrofits in the reference case reflect EPA cost assumptions, just as they do in the policy case.

To achieve the maximum level of unit-level detail on costs and compliance measures, we used the unit-specific inputs shown in Table C-1 to the maximum extent possible. For emission control costs without unit-specific inputs in NEMS, we used uniform inputs for all units. As shown above in Table C-1, NEMS has unit-specific inputs for scrubber capital costs and SCR capital and O&M costs, so we modified these unit-specific inputs to reflect EPA cost assumptions. Since NEMS only has uniform inputs for scrubber O&M costs and ACI and FF costs, we modified those uniform inputs to reflect EPA cost assumptions. Since NEMS does not model DSI, the variable O&M cost of FF, or the heat rate and capacity penalties of any emissions controls other than scrubbers, we adjusted the relevant unit parameters manually in the unit database. Our modifications for emission control costs are shown below in Table C-2.

Table C-2. Modification of NEMS Emission Control Costs

	Scrubbers	SCR	ACI	FF	DSI
Capital	Assign by unit using NEMS scrubber capital cost input variable	Assign by unit using NEMS SCR capital cost input variable	Assign uniform cost to all units	Assign uniform cost to all units	Assign by unit using NEMS general capital cost input variable
Fixed O&M	Assign uniform cost to all units	Assign by unit using NEMS SCR fixed O&M cost input variable	Assign uniform cost to all units	Assign uniform cost to all units	Assign by unit using NEMS general fixed O&M cost input variable
Variable O&M	Assign uniform cost to all units	Assign by unit using NEMS SCR variable O&M cost input variable	Assign uniform cost to all units	Assign by unit using NEMS general variable O&M cost input variable	Assign by unit using NEMS general variable O&M cost input variable
Heat Rate Penalty	Assign uniform penalty to all units	Assign by unit using NEMS heat rate input variable	Assign by unit using NEMS heat rate input variable	Assign by unit using NEMS heat rate input variable	Assign by unit using NEMS heat rate input variable
Capacity Penalty	Assign uniform penalty to all units	Assign by unit using NEMS capacity input variable	Assign by unit using NEMS capacity input variable	Assign by unit using NEMS capacity input variable	Assign by unit using NEMS capacity input variable

Source: NERA

b. Coal Unit Retirements

As described in Appendix B, we used the Retirement Model to determine which coal units would likely retire rather than incur costs for the four EPA regulations. We also used the Retirement Model for the reference case to determine which coal units would likely retire even in the absence of the four EPA regulations. We entered these retirements into the NEMS database of generation units for the end of 2014 (immediately before compliance with MACT, CCR, and 316(b) is assumed to be required in 2015). We did not allow NEMS to retire coal units based on its own economic evaluations in either the reference case or the policy case.[1]

c. Compliance Measures

The compliance measures that we modeled for CSAPR, MACT, CCR, and 316(b) for the policy case are described in Appendix A. That appendix also describes our modeling of compliance measures for the two most relevant environmental policies in the reference case: CAIR and state mercury regulations. Our methodology and assumptions are summarized briefly here.

We modeled CAIR in the reference case by setting regional emission caps through 2011 in NEMS and allowing NEMS to determine which coal units would need to install environmental controls or fuel switch to lower their SO_2 and NO_x emissions. We modeled state mercury regulations in the reference case by requiring mercury reductions in specific regions in NEMS based on the locations of states with mercury regulations and allowed NEMS to determine which coal units would need to install ACI, fabric filters, and/or scrubbers to comply.

For the policy case, we modeled CSAPR by setting regional caps in NEMS and allowing NEMS to determine which additional coal units would need to install environmental controls or fuel switch to lower their SO_2 and NO_x emissions beyond reductions for CAIR (or for caps without CAIR from 2012 onward). We modeled the MACT mercury standards by requiring mercury reductions based on the standards shown in Appendix A and allowing NEMS to determine which coal units would need to install ACI, fabric filters, and/or scrubbers to comply. We modeled the MACT HCl and PM standards by requiring scrubbers, DSI, and/or fabric filters at particular units, as discussed in detail in Appendix A. Finally, we modeled the CCR and 316(b) regulations in NEMS by applying their unit-specific costs in the NEMS database of generation units using the input variable for general capital costs, since NEMS does not model compliance with non-air emission regulations such as the CCR and 316(b) regulations.

[1] The NEMS model provides less detailed modeling of coal unit retirements than provided for in the retirement model we used. With regard to dispatch, NEMS provides for 216 distinct periods (summer, winter, spring and fall by peak, off-peak and weekend). As with other retirement models (see, e.g., Brattle Group 2010), our retirement model models the full 8,760 hours per year of electricity prices and thus allows for more precise dispatch modeling and forecasts of costs for existing and potential new units. Our model also incorporates uncertainties in key energy price and cost variables and allows the retirement decision to depend upon these uncertainties.

2. NEMS Outputs

Based on the coal unit retirements and the costs of the compliance measures, NEMS calculated the cost-minimizing set of energy prices and quantities. NEMS also endogenously determined the new generation capacity necessary in each electricity region to replace the coal units that would retire. The electricity price results from NEMS include the costs of compliance measures as well as the costs for new generation capacity, among other electricity price components.

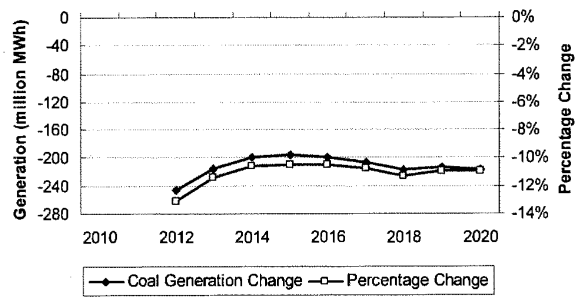
C. Results

This section shows key energy market impact results from NEMS due to the four EPA regulations for each year between 2012 and 2020.

1. Coal-Fired Generation

Figure C-2 shows the change in coal-fired generation between 2012 and 2020 due to the four EPA regulations relative to reference case projections. Coal-fired generation decreases because of the coal unit retirements and the additional costs borne by coal units that do not retire (which make the units less competitive in electricity markets and thus lower their capacity factors). Note that coal units incur costs for their SO_2 and NO_x emissions in the policy case beginning in 2012 due to the introduction of the trading program for CSAPR, with CAIR assumed not to be in place after 2011. In 2015, when many coal units install scrubbers and DSI for MACT HCl compliance, their SO_2 emissions decrease and allowance prices decrease to zero. As a result, coal units have lower costs for SO_2 emissions from 2015 onward than they had from 2012 to 2014. This tends to raise their capacity factors relative to their levels from 2012 to 2014. Coal unit retirements contribute to lower coal-fired generation from 2015 onward.

Figure C-2. Change in Coal-Fired Generation Relative to Reference Case

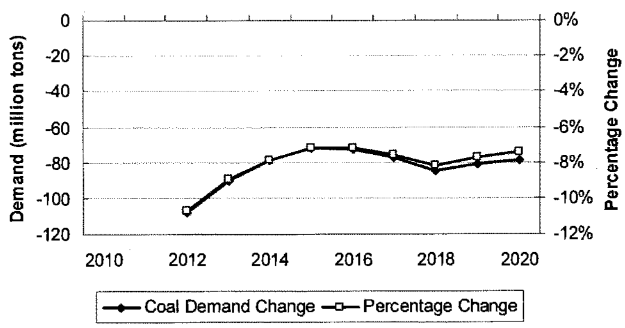


Note: Coal-fired generation in 2010 was 1800 million MWh (EIA 2011a).
Source: NERA calculations as explained in text

2. Electricity Sector Coal Demand

Figure C-3 shows the change in electricity sector coal demand between 2012 and 2020 due to the four EPA regulations relative to reference case projections. Just as for coal-fired generation, electricity sector coal demand decreases because of the coal unit retirements and the additional costs borne by coal units that do not retire (which make the units less competitive in electricity markets and thus lower their capacity factors). The percentage change in electricity sector coal demand is similar to the percentage change in coal-fired generation; the small difference between the percentage changes reflects shifts in the average heat content of coal consumed by units.

Figure C-3. Change in Electricity Sector Coal Demand Relative to Reference Case

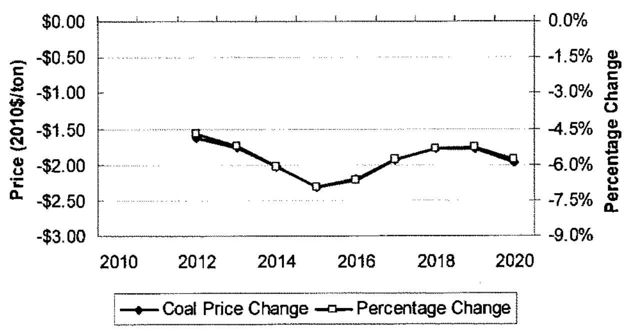


Note: Electricity sector coal demand in 2010 was 1000 million tons (EIA 2011a).
Source: NERA calculations as explained in text

3. Coal Price

Figure C-4 shows the change in average coal minemouth (i.e., wholesale) price between 2012 and 2020 due to the four EPA regulations relative to reference case projections. The price of coal would decrease because of reduced demand for coal by the electricity sector.

Figure C-4. Change in Average Coal Minemouth Price Relative to Reference Case

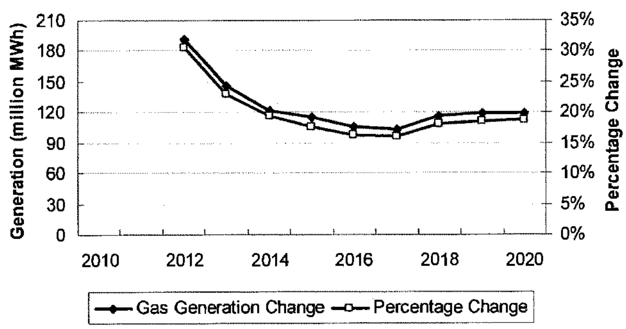


Note: Average coal minemouth price in 2010 was $37/ton (2010$) (EIA 2011a).
Source: NERA calculations as explained in text

4. Natural Gas-Fired Generation

Figure C-5 shows the change in natural gas-fired generation between 2012 and 2020 due to the four EPA regulations relative to reference case projections. When coal units retire and capacity factors for the remaining coal units decrease (due to the costs of environmental controls), the electricity sector shifts toward natural gas. The increase in natural-gas fired generation reflects both new gas units and higher capacity factors for existing gas units. The increase in natural gas-fired generation in each year is somewhat smaller than the decrease in coal-fired generation shown above in Figure C-2 because other energy sources also substitute for coal and total electricity consumption decreases somewhat in response to higher electricity prices (shown below in Figure C-8).

Figure C-5. Change in Natural Gas-Fired Generation Relative to Reference Case

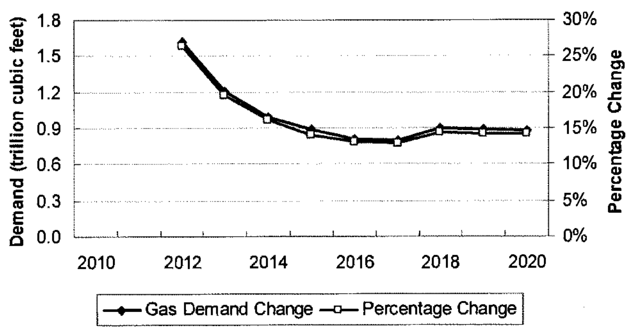


Note: Natural gas-fired generation in 2010 was 750 million MWh (EIA 2011a).
Source: NERA calculations as explained in text

5. Electricity Sector Natural Gas Demand

Figure C-6 shows the change in electricity sector natural gas demand between 2012 and 2020 due to the four EPA regulations relative to reference case projections. Just as for natural gas-fired generation, the increase in electricity sector natural gas demand reflects both new gas units and higher capacity factors for existing gas units. The percentage change in electricity sector natural gas demand in each year is similar to the percentage change in natural gas-fired generation.

Figure C-6. Change in Electricity Sector Natural Gas Demand Relative to Reference Case

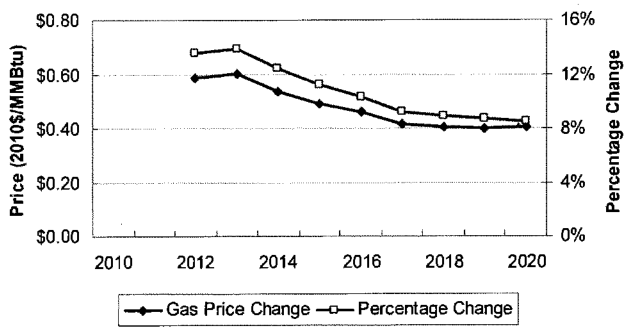


Note: Electricity sector natural gas demand in 2010 was 7.2 trillion cubic feet (EIA 2011a).
Source: NERA calculations as explained in text

6. Natural Gas Price

Figure C-7 shows the change in natural gas price at Henry Hub between 2012 and 2020 due to the four EPA regulations relative to reference case projections. The price of natural gas would increase because of the substantial increase in demand for natural gas by the electricity sector (taking into account the reduction in natural gas demand in other sectors as prices rise).

Figure C-7. Change in Natural Gas Price at Henry Hub Relative to Reference Case



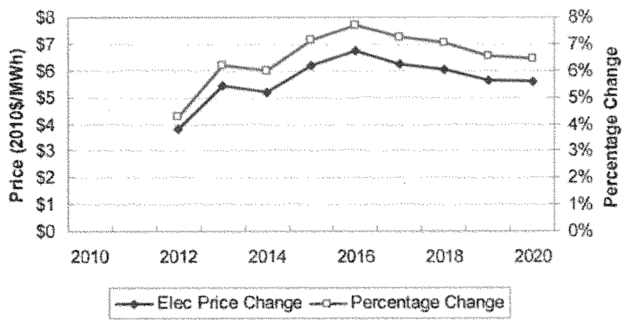
Note: Average natural gas price at Henry Hub in 2010 was $4.50/MMBtu (2010$) (EIA 2011a).
Source: NERA calculations as explained in text

7. Electricity Price

a. U.S. Electricity Price

Figure C-8 shows the change in average U.S. electricity retail price between 2012 and 2020 due to the four EPA regulations relative to reference case projections. The increase in electricity price reflects environmental control costs at coal units that do not retire, SO_2 and NO_x emission costs for CSAPR, construction of new gas units and increased capacity factors for existing gas units, and higher natural gas price.

Figure C-8. Change in Average U.S. Electricity Retail Price Relative to Reference Case

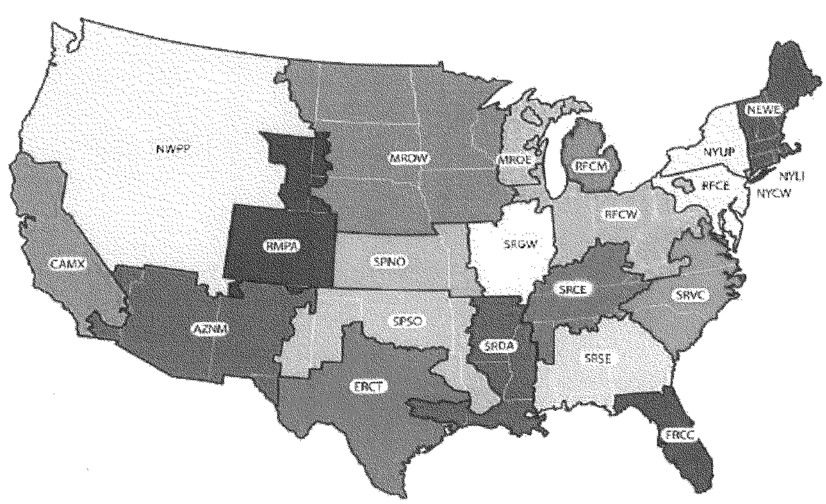


Note: Average U.S. electricity retail price in 2010 was $97/MWh (2010$) (EIA 2011a).
Source: NERA calculations as explained in text

b. Regional Electricity Price

Figure C-9 provides a map of the 22 electricity regions modeled in NEMS.

Figure C-9. NEMS Electricity Regions



Source: EIA (2011b, p. 95)

Table C-3 provides estimates of the electricity retail price impacts in the 22 NEMS electricity regions between 2012 and 2020 due to the four EPA regulations. The impacts reflect different extents to which natural gas prices, coal prices, emission allowance costs, coal unit retirements, and retrofits affect electricity prices in each year in different regions. For example, regions that rely much more on natural gas-fired generation than coal-fired generation (e.g., New England) have larger impacts during 2012-2014 than 2015-2020, because the increase in natural gas prices tapers off over time (see Figure C-7). On the other hand, regions that rely much more on coal-fired generation than natural gas-fired generation (e.g., Kentucky and Tennessee) have smaller impacts during 2012-2014 than 2015-2020, because coal unit retirements and most retrofits occur in 2015.

Table C-3. Regional Electricity Retail Price Impacts, 2012-2020 (2010$/MWh)

		2012	2013	2014	2015	2016	2017	2018	2019	2020	Avg
	US Average	+$3.80	+$5.45	+$5.21	+$6.18	+$6.73	+$6.25	+$6.06	+$5.62	+$5.56	+$5.65
NEMS Regions											
NEWE	New England	+$4.01	+$5.81	+$4.98	+$4.89	+$2.99	+$1.61	+$0.99	+$1.30	-$0.24	+$2.93
NYCW	NYC	+$6.63	+$10.35	+$8.90	+$8.12	+$6.91	+$5.95	+$5.47	+$5.21	+$5.23	+$6.97
NYLI	NY Long Island	+$10.77	+$17.39	+$15.45	+$14.09	+$12.48	+$12.22	+$11.65	+$11.40	+$11.53	+$13.00
NYUP	NY Upstate	+$6.14	+$9.37	+$8.04	+$6.65	+$5.45	+$5.33	+$5.32	+$5.59	+$5.62	+$6.39
RFCE	Mid-Atlantic	+$8.29	+$13.26	+$11.41	+$12.57	+$10.81	+$11.26	+$10.69	+$7.24	+$7.88	+$10.38
SRVC	VA & Carolinas	+$2.63	+$3.71	+$3.71	+$4.13	+$4.91	+$4.72	+$4.41	+$4.13	+$4.06	+$4.05
SRSE	Southeast	+$3.19	+$4.29	+$5.15	+$7.17	+$9.63	+$8.97	+$8.51	+$8.02	+$7.53	+$6.94
FRCC	Florida	+$3.60	+$4.81	+$4.22	+$4.22	+$4.42	+$4.20	+$3.96	+$3.64	+$3.82	+$4.10
RFCM	Lower MI	+$3.70	+$5.41	+$7.10	+$7.31	+$10.00	+$9.51	+$8.83	+$8.46	+$8.35	+$7.63
RFCW	OH, IN, & WV	+$5.42	+$8.65	+$8.08	+$7.18	+$7.12	+$6.85	+$6.59	+$6.48	+$6.70	+$7.01
SRCE	KY & TN	+$4.68	+$4.38	+$5.30	+$9.11	+$11.36	+$10.88	+$10.25	+$9.93	+$9.37	+$8.36
MROE	WI & Upper MI	+$5.63	+$7.78	+$8.12	+$6.57	+$7.37	+$7.14	+$6.79	+$6.54	+$6.66	+$6.96
MROW	Upper Midwest	+$1.41	+$1.11	+$1.23	+$4.90	+$8.36	+$8.20	+$7.94	+$7.85	+$7.54	+$5.39
SRGW	South IL & East MO	+$3.98	+$5.83	+$6.20	+$6.69	+$8.59	+$8.11	+$7.49	+$6.93	+$6.72	+$6.73
SPNO	KS & West MO	+$5.46	+$2.35	+$3.13	+$4.84	+$8.10	+$7.98	+$8.17	+$8.61	+$9.13	+$6.42
SRDA	AR, LA, & West MS	+$2.03	+$3.40	+$4.27	+$5.14	+$6.96	+$6.56	+$6.29	+$5.98	+$5.80	+$5.16
SPSO	Oklahoma	+$3.33	+$7.65	+$8.27	+$8.89	+$11.13	+$10.61	+$9.75	+$9.43	+$9.68	+$8.75
ERCT	Texas	+$4.85	+$7.01	+$6.14	+$9.15	+$6.27	+$3.51	+$4.34	+$3.60	+$3.16	+$5.34
RMPA	CO & East WY	+$0.60	+$0.40	+$0.70	+$1.54	+$2.16	+$1.99	+$1.86	+$1.72	+$1.65	+$1.40
NWPP	Northwest	-$0.14	-$0.30	-$2.27	-$1.22	-$0.07	+$0.38	+$1.20	+$1.40	+$1.36	+$0.04
AZNM	AZ & NM	+$0.82	+$0.70	+$1.04	+$1.39	+$1.71	+$1.69	+$1.56	+$1.86	+$1.85	+$1.40
CAMX	California	+$1.34	+$2.05	+$2.19	+$2.26	+$2.28	+$2.59	+$2.59	+$2.45	+$2.45	+$2.25

Source: NERA calculations as explained in text

Table C-4 shows the percentage changes in electricity retail prices in the 22 NEMS electricity regions relative to reference case projections.

Table C-4. Regional Electricity Retail Price Impacts, 2012-2020 (Percentage Changes)

		2012	2013	2014	2015	2016	2017	2018	2019	2020	Avg
	US Average	+4.3%	+6.2%	+6.0%	+7.1%	+7.7%	+7.2%	+7.0%	+6.5%	+6.5%	+6.5%
NEMS Regions											
NEWE	New England	+2.9%	+4.3%	+3.7%	+3.7%	+2.3%	+1.2%	+0.7%	+1.0%	-0.2%	+2.2%
NYCW	NYC	+3.8%	+6.1%	+5.3%	+4.9%	+4.2%	+3.6%	+3.4%	+3.2%	+3.2%	+4.2%
NYLI	NY Long Island	+6.3%	+10.4%	+9.4%	+8.7%	+7.7%	+7.6%	+7.3%	+7.1%	+7.2%	+8.0%
NYUP	NY Upstate	+5.0%	+7.9%	+6.9%	+5.8%	+4.8%	+4.7%	+4.8%	+5.0%	+5.0%	+5.6%
RFCE	Mid-Atlantic	+8.4%	+13.7%	+11.9%	+13.1%	+11.3%	+11.7%	+11.0%	+7.4%	+7.8%	+10.7%
SRVC	VA & Carolinas	+3.3%	+4.6%	+4.7%	+5.2%	+6.3%	+6.1%	+5.6%	+5.2%	+5.0%	+5.1%
SRSE	Southeast	+3.8%	+5.3%	+6.5%	+9.1%	+11.9%	+10.4%	+9.6%	+8.9%	+8.3%	+8.2%
FRCC	Florida	+3.4%	+4.5%	+4.0%	+4.0%	+4.2%	+4.0%	+3.8%	+3.5%	+3.7%	+3.9%
RFCM	Lower MI	+4.7%	+6.9%	+9.1%	+9.2%	+12.4%	+11.7%	+10.9%	+10.5%	+10.4%	+9.5%
RFCW	OH, IN, & WV	+6.2%	+10.2%	+9.7%	+8.7%	+8.7%	+8.5%	+8.3%	+8.3%	+8.6%	+8.6%
SRCE	KY & TN	+7.2%	+6.9%	+8.5%	+14.7%	+18.6%	+17.9%	+17.0%	+16.5%	+15.5%	+13.6%
MROE	WI & Upper MI	+7.6%	+10.5%	+10.7%	+8.7%	+9.4%	+9.3%	+8.9%	+8.7%	+8.8%	+9.2%
MROW	Upper Midwest	+2.0%	+1.6%	+1.7%	+7.0%	+12.1%	+11.9%	+11.6%	+11.6%	+11.3%	+7.9%
SRGW	South IL & East MO	+6.5%	+9.6%	+10.3%	+11.0%	+14.1%	+13.3%	+12.4%	+11.5%	+11.2%	+11.1%
SPNO	KS & West MO	+6.9%	+2.8%	+3.7%	+5.8%	+9.9%	+9.9%	+10.4%	+11.1%	+12.0%	+8.1%
SRDA	AR, LA, & West MS	+2.7%	+4.6%	+5.9%	+7.1%	+9.9%	+9.4%	+9.0%	+8.7%	+8.4%	+7.3%
SPSO	Oklahoma	+4.7%	+11.1%	+12.0%	+12.8%	+16.0%	+15.3%	+14.1%	+13.6%	+14.0%	+12.6%
ERCT	Texas	+6.4%	+9.4%	+8.3%	+12.2%	+8.1%	+4.4%	+5.5%	+4.5%	+3.9%	+7.0%
RMPA	CO & East WY	+0.7%	+0.4%	+0.8%	+1.7%	+2.4%	+2.2%	+2.1%	+1.9%	+1.9%	+1.6%
NWPP	Northwest	-0.2%	-0.5%	-3.7%	-2.0%	-0.1%	+0.6%	+2.1%	+2.5%	+2.5%	+0.1%
AZNM	AZ & NM	+1.0%	+0.8%	+1.2%	+1.6%	+1.9%	+1.9%	+1.8%	+2.1%	+2.1%	+1.6%
CAMX	California	+0.9%	+1.4%	+1.5%	+1.6%	+1.6%	+1.9%	+1.9%	+1.8%	+1.8%	+1.6%

Source: NERA calculations as explained in text

D. References

Brattle Group. 2010. *Potential Coal Plant Retirements Under Emerging Environmental Regulation.* Cambridge, MA: Brattle Group, December 8.

U.S. Energy Information Administration. 2009. *The National Energy Modeling System: An Overview 2009.* Washington, D.C.: EIA, October. (www.eia.gov/FTPROOT/-forecasting/05812009.pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011a. *Annual Energy Outlook 2011.* Washington, D.C.: EIA, April. (www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011b. *Assumptions to the Annual Energy Outlook 2011.* Washington, D.C.: EIA, July. (www.eia.gov/forecasts/aeo/assumptions/pdf/-0554(2011).pdf, accessed September 20, 2011)

Appendix D: Macroeconomic Modeling

This appendix provides details on the Policy Insight Plus (PI+) macroeconomic model developed and licensed by Regional Economic Models, Inc. (REMI) as well as our data and methodology for using this model to estimate the potential macroeconomic impacts of the EPA regulations.

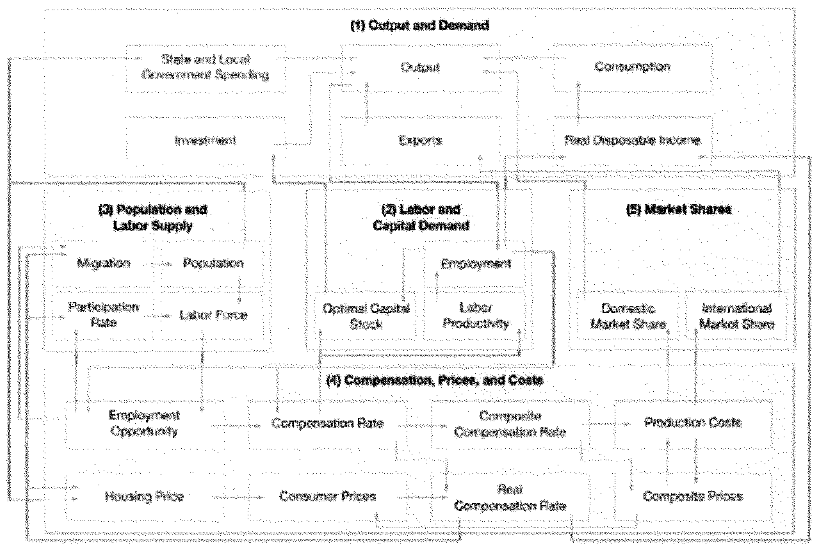
A. Overview of REMI Model[1]

The REMI PI+ model produces estimates of the changes in employment, gross domestic product (GDP), disposable personal income (i.e., personal income after taxes), and other macroeconomic variables due to changes in supply, demand, prices, and other types of inputs. Each version of the REMI PI+ model is custom-built for the regions of interest, which can range from counties to entire countries. The REMI PI+ model incorporates detailed and up-to-date macroeconomic data from the U.S. Bureau of Economic Analysis, the U.S. Bureau of Labor Statistics, the U.S. Census Bureau, and other public sources. The REMI PI+ model is widely used by federal, state, and local agencies, as well as analysts in the private sector and academia, to estimate the effects of regulations, investments, closures, and other scenarios.

Figure D-1 shows the five blocks in the REMI PI+ model and their linkages. The Output and Demand block balances supply and demand for all major sectors of the economy, including both domestic and international sources of supply and demand. The Labor and Capital Demand block models employment and capital stock based on output, wage rates, and capital costs. The Population and Labor Supply block models labor participation rate and population based on wage rates in the various regions and the size of the various sectors. The Compensation, Prices, and Costs block models each sector's production cost, including labor cost based on wage rates. Finally, the Market Shares block uses production cost to model each sector's domestic market share and international market share, which are passed back up to the Output and Demand block.

[1] This section draws on model documentation from Regional Economic Models, Inc. (REMI 2011).

Figure D-1. Key Blocks and Linkages in the REMI Model



Source: REMI (2011)

B. Overview of Methodology

We modeled the potential macroeconomic impacts of the EPA regulations using a 70-sector REMI PI+ model covering the entire United States. The model has regional detail based on Census divisions.

We developed inputs to the REMI model using the energy market modeling results from NEMS for the four EPA regulations.[2] Inputs to the REMI model can take the form of either dollar amounts or percentage changes from the built-in forecasts in the model. We entered all our inputs for this study as dollar amounts measured in constant dollars.

The types of REMI inputs developed from NEMS and other sources are summarized below.

1. *Environmental control costs.* We developed inputs for the positive effects of the capital and operations and maintenance (O&M) costs of environmental controls at the coal units that do not retire. These inputs include the costs of all the projected scrubbers, SCR, ACI, fabric filters, DSI, and compliance measures for the CCR and 316(b) regulations, broken out to the specific model regions in which they are projected to occur. We used the same cost

[2] Details on the energy market modeling results from NEMS are provided in Appendix C.

assumptions as those used in modeling potential coal unit retirements. These capital and O&M costs enter the REMI model as increased demand for machinery manufacturing and construction.

2. *Replacement capacity costs.* We developed REMI inputs for the positive effects of capital costs of new generation capacity to replace the coal units that are projected to retire. Most of the replacement capacity is combined-cycle gas technology. We developed estimates of the capital costs of replacement capacity using energy market modeling results and capital cost assumptions from NEMS. These capital costs enter the REMI model as increased demand for machinery manufacturing and construction.[3] The costs are apportioned to model regions based upon the regions where NEMS has projected the construction of new units will occur.

3. *Coal sales decreases.* We developed REMI inputs reflecting the negative effects of reductions in coal sales. These reductions arise both from coal unit retirements and from the lower capacity factors for coal units that continue to operate but are utilized less because their generation costs are greater due to controls. We developed estimates of reductions in coal sales using regional coal production and mine mouth (i.e., wholesale) price results from NEMS. The NEMS results reflect estimates of changes in coal demand not only in the electricity sector but also in the residential, commercial, and industrial sectors; the changes in these other sectors are small because these other sectors consume very little coal relative to the electricity sector. The values enter the REMI model as decreased sales for the mining sector in the relevant regions.

4. *Coal price decreases.* We developed REMI inputs for the negative impacts of decreases in coal prices on producers due to the decreased demand for coal in the electricity sector. The gains to electricity consumers from the lower coal prices are included below in the estimated effects of changes in electricity prices (which reflect the net effect of compliance costs and changes in fuel costs). In principle, the reductions in coal prices would lead to gains to consumers in non-electric sectors. NEMS does not provide information on coal prices and costs for these sectors that would allow us to assess these potential effects but they would be small because non-electric coal use is a small fraction of utility coal use.[4] We developed estimates of the decreases in coal prices using regional coal production and mine mouth (i.e., wholesale) price results from NEMS. The negative impacts on producers enter the REMI model as decreases in dividend income and government transfer payments (due to the decrease in government tax receipts from lower dividend income taxes).

---

[3] The O&M costs of replacement capacity are assumed to be approximately equal to the avoided O&M costs of the coal units that retire. Thus, neither the O&M costs of replacement capacity nor the avoided O&M costs of the coal units that retire are entered into the REMI model, as they would cancel each other out. Since O&M costs of the generating units themselves are small relative to the other inputs to the REMI model, omission of the O&M costs of replacement capacity and coal units that retire does not significantly affect the results of the macroeconomic modeling. In contrast, we do include inputs to reflect the O&M costs of new retrofits as noted above.

[4] The residential, commercial, and industrial sectors collectively accounted for less than 7 percent of total U.S. coal consumption in 2010 (EIA 2011a). Coal price effects for these sectors are considerably smaller than any other effect included in this macroeconomic impact analysis.

5. *Natural gas sales increases.* We developed REMI inputs for the positive impacts of increases in natural gas sales due to the increase in demand from the electricity sector (from new natural gas units replacing the coal units that retire and higher capacity factors for existing gas units). The net increase in natural gas sales, however, is smaller than the increase in electricity demand because the increases in natural gas prices lead to reduced demand from residential, commercial and industrial sectors.[5] We developed estimates of the net increase in natural gas sales using regional natural gas production and wellhead (i.e., wholesale) price results from NEMS. The values enter the REMI model as increased sales for the oil and gas extraction sector.

6. *Natural gas price increases.* We developed REMI inputs for both the positive impacts on natural gas producers of higher natural gas prices (relative to cost increases) and the negative effects of higher natural gas prices on non-utility consumers. (As with coal prices, the negative effects on electric company customers are included in the electricity price impacts.) We developed regional estimates of the increase in natural gas prices using regional natural gas consumption and retail price results for the residential, commercial, and industrial sectors from NEMS. The impacts on consumers enter the REMI model for households as decreases in purchasing power due to increases in natural gas prices and for commercial and industrial sectors as increases in natural gas costs. The impacts on producers enter the REMI model as increases in dividend income and government transfer payments (due to the increase in government tax receipts associated with dividend income taxes).

7. *Electricity price increases.* We developed REMI inputs for the negative impacts of increases in electricity prices on consumers (residential, commercial, and industrial). Because changes in electricity sector costs—for pollution control equipment and fuel price changes—are reflected in electricity prices, electricity producers as a group are not expected to be affected. We developed regional estimates of the increase in electricity prices for consumer groups using regional electricity consumption and retail price results for the residential, commercial, and industrial sectors from NEMS. These values enter the REMI model as increases in electricity price (change in purchasing power) for households and electricity costs for commercial and industrial sectors in the various regions.

8. *Financing of capital costs.* This component arises because the capital costs for pollution control and new capacity are not reflected fully in electricity rates in the years in which they are incurred, although these costs are ultimately reflected in higher electricity rates (as noted above). We developed information on the financing of pollution control and replacement capacity expenditures, in particular the extent to which these capital expenditures would lead to reduced investment or reduced consumption in the years in which the capital expenditures are made, and then increased investment or increased consumption in the years in which

[5] We used the version of REMI that allows for complete fuel substitution for other factor inputs, which assumes that consumers can shift away from more expensive energy and thus reduce the negative impacts of higher natural gas and electricity prices. This assumption may understate the negative imacts of the price increases. We also entered the costs of substitution away from energy into the REMI model as increased demand for energy-efficient appliances. Including this effect may overstate the positive impacts if the REMI model already incorporates these positive adjustments related to substitution away from energy.

electricity price increases reflect these capital costs but the capital expenditures have already been made.

C. Information on Modeling Components

This section provides additional information on the inputs to the REMI modeling.[6]

1. Environmental Control Costs

Environmental control costs consist of the capital and O&M costs for compliance measures at the coal units that do not retire. As discussed in the report body, we assumed that CSAPR would take effect in 2012 and MACT, CCR, and 316(b) would take effect in 2015. The NEMS results reflect compliance in these years, but that model does not incorporate leadtimes for controls. NEMS builds some scrubbers for compliance with the CSAPR SO_2 policy in 2012, and it builds other controls by 2015. We entered the capital costs of controls installed in 2012 into the REMI model as costs in 2012, and we entered the capital costs of controls installed in 2015 into the REMI model as costs spread evenly in 2013, 2014, and 2015 to reflect their leadtime. Costs from 2016 onward primarily reflect the O&M cost of environmental controls. The costs are net of pollution control costs in the reference scenario (which primarily reflect currently planned retrofits by 2012 and mercury controls for state policies in the reference case).

The environmental control costs represent increased demand for manufacturers and construction companies. We reviewed detailed budgets for several retrofit projects in the electricity sector (e.g., PSNH 2010, DOE 2003) and determined that approximately 70 percent of the costs were for equipment and 30 percent for construction. Thus, we modeled 70 percent of the environmental control costs in each year in REMI as increased demand for the machinery manufacturing sector and the remaining 30 percent as increased demand for the construction sector. These environmental control costs are allocated to regions in REMI based on the locations of the coal units incurring the costs.

2. Replacement Electricity Capacity Costs

Replacement capacity costs consist of the capital costs for new electricity capacity (primarily combined-cycle gas units) that NEMS projects will be built, based on its evaluation of supply and demand in regional electricity markets, to replace the coal units that retire.[7] Most of the

---

6 We considered using the optional NEMS macroeconomic activity module to develop the macroeconomic impact estimates but concluded that it would be less appropriate than REMI for this study. The NEMS macroeconomic module uses only changes in energy prices and quantities from NEMS to assess macroeconomic impacts. Thus, the module does not account for the increase in demand for machinery manufacturing and construction or the need to finance the capital expenditures. REMI allows us to incorporate both effects. Moreover, the NEMS macroeconomic module aggregates all energy price changes (including electricity, coal, and natural gas) into a single energy price index for purposes of evaluating macroeconomic impacts. REMI allows us to input separate estimates for the different energy types.

7 As noted above, neither the O&M costs for replacement capacity nor the avoided O&M costs for coal units that retire are included in the macroeconomic modeling, because they are assumed to be approximately equal in size and therefore would cancel each other out.

replacement capacity is built shortly before 2015 in anticipation of the many coal unit retirements in that year, but some replacement capacity is built later in the modeling period. The assumed capital costs for new capacity are based upon EIA estimates (2011b, p. 97). The replacement capacity costs are net of new capacity costs in the reference scenario. (The four policies pull forward some new capacity that would be built later in the reference scenario.)

The replacement capacity costs represent increased demand for manufacturers and construction companies. Based on our review of electricity sector project budgets (described above), we assumed that 70 percent of the capital costs were for equipment and 30 percent for construction. Thus, we modeled 70 percent of the replacement capacity costs in each year in REMI as increased demand for the machinery manufacturing sector and the remaining 30 percent as increased demand for the construction sector.

NEMS generates estimates of replacement capacity costs for each of its 22 electricity regions, which are based on electric reliability regions defined by the North American Electric Reliability Corporation (NERC). We allocated these values to the regions in the REMI model based upon the shares of baseline generation capacity.

3. Coal Sales Reduction

The coal unit retirements and reduction in capacity factors for non-retiring coal units projected due to the four regulations would lead to decreased demand for coal in the electricity sector. We modeled the reduction in coal sales using regional NEMS results on coal production and minemouth (i.e., wholesale) price. In particular, we calculated the change in coal production in each region and multiplied it by the average of the minemouth prices in the reference case and policy case in each region to capture the quantity effect of the four regulations for coal.[8] We allocated these values to the regions in the REMI model based on the regional data from NEMS. The values enter the REMI model as decreased sales for the mining sector.

4. Coal Price Decreases

This section considers the effects of coal price decreases on producer surplus. As noted above, we did not model coal price effects on consumers because the price effect for the electricity sector is included in the electricity price effects and the price effects for residential, commercial, and industrial sectors are negligible because of their low coal consumption.

The reduction in coal prices due to reduced demand by the electricity sector would reduce producer surplus in the coal sector.[9] We developed REMI inputs for this reduction in producer surplus in the coal sector based on NEMS results by multiplying the change in coal minemouth price (a negative value) by the average of coal productions in the reference and policy cases. We entered the reduction in producer surplus into the REMI model as reductions in dividend income and allocated it across regions based on their share of the U.S. population. Since dividends are

[8] The price effects on consumer and producers surplus are modeled below.

[9] Producer surplus is the amount by which price exceeds marginal cost (or the minimum amount that producers would accept to produce the good), summed over all production. It relates to total profit in a sector.

distributed by companies after paying income taxes, we first multiplied the producer surplus by an estimated effective corporate income tax rate and modeled this change in government corporate income tax receipts as a change in transfer payments. We used an estimated effective corporate income tax rate of 40 percent based on a review of tax rates for energy companies (API 2010, p. 7) and allocated the change in transfer payments across regions based on their share of the U.S. population. We then modeled the remainder of producer surplus as dividend payments.

5. Natural Gas Sales Increase

The new gas units and higher capacity factors for existing gas units due to the four regulations would lead to increased demand for natural gas in the electricity sector. Since higher natural gas prices in the REMI model lead to lower natural gas sales, but the regulations would lead to both higher natural gas prices and higher natural gas sales due to the outward shift of the demand curve for natural gas in the electricity sector, we needed to calibrate the natural gas sales inputs to ensure that the REMI results would be consistent with the NEMS results for natural gas sales. We did this by running the REMI model first with the inputs shown above except the change in natural gas sales, examining the natural gas sales results from the REMI model, and calibrating the natural gas sales inputs to correspond with the values from NEMS. We modeled the increase in natural gas sales using regional NEMS results on natural gas production and wellhead (i.e., wholesale) price. In particular, we calculated the change in natural gas production in each region and multiplied it by the average of the wellhead prices in the reference case and policy case in each region to capture the quantity effect of the four regulations for natural gas. We allocated these values to the regions in the REMI model based on the regional data from NEMS. The values enter the REMI model as increased sales for the oil and gas extraction sector.

6. Natural Gas Price Increases

This section considers the impacts of increases in natural gas prices—due to increased electricity sector demand—on consumers and producers.

a. Impacts on Natural Gas Consumers

The increase in natural gas demand in the electricity sector would increase the price of natural gas for all sectors of the economy. We used regional NEMS results on natural gas consumption and retail prices for the residential, commercial, and industrial sectors to develop REMI inputs for these adverse consumer impacts. NEMS produces these results for the nine Census divisions. We calculated the change in retail natural gas price in each region and multiplied it by the average consumption in the reference and policy cases in each region to capture the price effect of the four regulations for natural gas. We allocated these values to the regions in the REMI model based on their historical shares of natural gas expenditures in their Census divisions. We entered the values for the residential sector in the REMI model as decreased household purchasing power (reflecting the increased natural gas prices), and we entered the values for the commercial and industrial sectors as increased natural gas costs for these sectors.

b. Impacts on Natural Gas Producers

The increase in natural gas prices due to expanded demand by the electricity sector would increase producer surplus in the natural gas sector. As with producer surplus in the coal sector, we modeled the increase in natural gas as increases in dividend payments and government transfer payments, using an effective corporate income tax rate of 40 percent. The change in producer surplus is calculated as the change in wellhead price multiplied by the average production in the reference and policy cases.

7. Electricity Price Increases

The four regulations would lead to increases electricity prices for the residential, commercial, and industrial sectors. We used regional NEMS results on electricity consumption and retail prices for the residential, commercial, and industrial sectors to develop REMI inputs for this type of impact.[10] NEMS produces these results for the nine Census divisions. We calculated the change in retail electricity price in each region and multiplied it by baseline consumption in each region to capture the price effect of the four regulations for electricity. We allocated these values to the regions in the REMI model based on their historical shares of electricity expenditures in their Census divisions. We entered the values for the residential sector in the REMI model as increased electricity price (change in purchasing power) for households, and we entered the values for the commercial and industrial sectors as increased electricity costs for these sectors.

8. Financing of Capital Costs

We presume that electricity companies would finance the net capital cost requirements (capital costs for environmental controls and new capacity minus contemporaneous electricity rate increase due to financing) in each year through debt financing. The impacts on the economy in each year would depend in part upon the extent to which the increased utility demand for capital—primarily from 2012 to 2015, with much smaller investment required from 2016 onward for replacement capacity–would lead to reductions in investment elsewhere in the economy, i.e., crowd out other investment. Since the REMI model does not reflect changes in the overall productivity of the economy due to changes in investment, however, the distinction between changes in investment and changes in consumption as the source of financing is less important.[11]

The extent of crowding out of other investment depends upon the short-run demand and supply elasticities for investment capital as well as on the detailed general equilibrium effects in the overall economy. If the short-run capital supply elasticity is zero, as many researchers have found (see Bernheim 2002), 100 percent of the increased demand by the electricity companies would be reflected in reduced investment elsewhere.

---

[10] Note that the changes in retail electricity prices from NEMS reflect the annualized costs of environmental controls and replacement capacity, not the actual expenditures by the electricity sector in each year. This issue is discussed below in the context of financing.

[11] Studies suggest that the general equilibrium economic effects of crowding out productive investment could be substantial. See Schmalensee (1994).

Various studies have considered the specific crowding out of pollution control expenditures. Gray and Shadbegian (2001) find that pollution control expenditures in the pulp and paper sector actually lead to more than a 100 percent reduction in other capital expenditures in the sector when account is taken of reductions at individual plants (188 percent decline) and approximately 100 percent decline considering only capital expenditures at other facilities. Jorgenson and Wilcoxen (1990) in their study of the effects of pollution control expenditures on the U.S. economy use a short-run elasticity for the supply of capital of zero (i.e., perfectly inelastic), implying 100 percent crowding out of investment in the short-term.

One plausible alternative is to assume 100 percent crowding out of private investment, based upon estimates of a zero short-term elasticity of supply of capital and some of the empirical estimates for compliance costs. Since the elasticity of supply may be greater than zero, we assumed crowding out of 50 percent for the net investment years.[12] We presumed that that the other 50 percent of net utility investment would come from additional savings and thus reduced consumption.[13] We presumed that the bondholders would receive additional income in the later years.

The reduced private investment is entered into REMI as reduced investment in residential structures, nonresidential structures, and nonresidential equipment based on their shares of baseline U.S. investment. The change in income for bondholders is entered into the REMI model as changes in consumption.[14]

D. Modeling Results for the Four Environmental Policies

We modeled the potential net macroeconomic impacts of the four regulations by entering all the inputs categories described above into the REMI model. We also calibrated the REMI model to ensure that the net changes in sales for the coal, natural gas, and electricity sectors with all the inputs were consistent with their net changes in sales from NEMS.[15]

[12] If the modeling included the negative effects of crowding out productive investment on economic growth, it would be more important to be precise about the specific amount of crowding out of private investment.

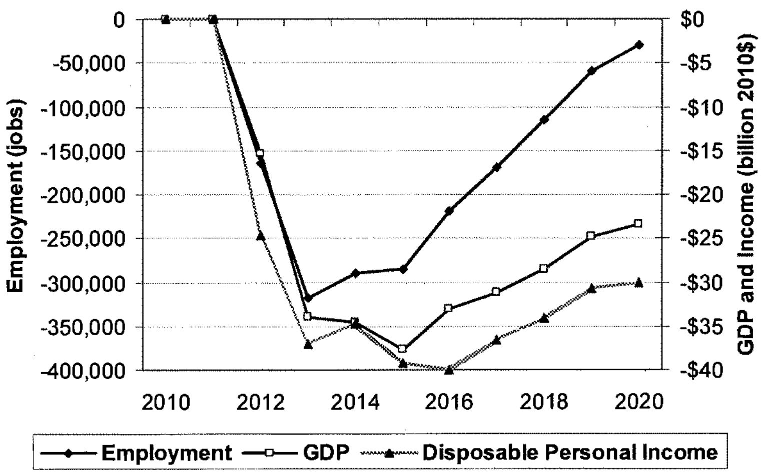
[13] These calculations presume that environmental compliance expenditures do not use unemployed or idle resources. As Schmalensee (1994) points out, there is no reason why tightening environmental regulation would weaken economy-wide forces that produce unemployment and, indeed, that the net short-term impact of tightening environmental standards is likely to increase overall unemployment in the near term in the process of shifting jobs within the economy (with monetary and fiscal policies, changes in exchange rates, changes in foreign economic policies and economic conditions and firm and household expectations being the major factors determining overall macroeconomic conditions).

[14] Entering the change in income alternatively as a change in dividends, interest, and rent would yield very similar results (because REMI indicates that dividends, interest, and rent in any year are mostly used for consumption in that same year).

[15] We performed this calibration by (1) running REMI once with all inputs except changes in sales; (2) calculating the difference between changes in sales from REMI for the coal, natural gas, and electricity sectors and their changes in sales from NEMS; and (3) running REMI again with the difference in sales (in addition to other inputs) so that the sales results from REMI would be consistent with the sales results from NEMS.

Figure D-2 shows the annual impacts of the four environmental policies on U.S. employment, GDP, and disposable personal income from 2012 to 2020 predicted by the REMI model.

Figure D-2. Macroeconomic Modeling Results



Source: NERA calculations as explained in text

E. References

American Petroleum Institute. 2011. *Putting Earnings in Perspective: Facts for Addressing Energy Policy*. Washington, D.C.: API, July 12. (www.api.org/statistics/-earnings/upload/earnings_perspective.pdf, accessed September 20, 2011)

Bernheim, B. Douglas. 2002. "Taxation and Saving", ch. 18, p. 1173-1249 in Auerbach, A. J. and Feldstein, M. eds., *Handbook of Public Economics*, vol. 3, Elsevier.

Gray, W. B. and Shadbegian, R. J. 1998. "Environmental Regulation, Investment Timing, and Technology Choice." *The Journal of Industrial Economics* 46: 235–256.

Jorgenson, Dale W. and Peter J. Wilcoxen. 1990. "Environmental Regulation and U.S. Economic Growth." *RAND Journal of Economics* 21(2): 314-340.

Public Service of New Hampshire. 2010. *Clean Air Project: Merrimack Station*. Prepared for the New Hampshire Public Utilities Commission: Docket 08-103 Informational Session. March 31. (www.puc.nh.gov/Regulatory/CaseFile/2008/08-103/LETTERS,%20MEMOS/08-103%202010-03-31%20PSNH%20Clean%20Air%20Project.pdf, accessed September 20, 2011)

Regional Economic Models, Inc. 2011. "The REMI Model." (www.remi.com/index.php?page=model&hl=en_US, accessed September 20, 2011)

Schmalensee, Richard. 1994. *The Costs of Environmental Protection*, in *Balancing Economic Growth and Environmental Goals*, Washington, D.C.: American Council for Capital Formation Center for Policy Research, pp. 55-80.

U.S. Department of Energy. 2003. *An Investigation of Site-Specific Factors for Retrofitting Recirculating Cooling Towers at Existing Power Plants*. Prepared for the U.S. DOE National Energy Technology Laboratory by Parsons Infrastructure and Technology Group, Inc. January 22. (www.netl.doe.gov/technologies/coalpower/ewr/water/pdfs/316b_NETL_ParsonFinalReport_wAddnd_012203.pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011a. *Annual Energy Outlook 2011*. Washington, D.C.: EIA, April. (www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011b. *Assumptions to the Annual Energy Outlook 2011*. Washington, D.C.: EIA, July. (www.eia.gov/forecasts/aeo/assumptions/pdf/-0554(2011).pdf, accessed September 20, 2011)

NERA
Economic Consulting

NERA Economic Consulting
200 Clarendon Street, 11th Floor
Boston, Massachusetts 02116
Tel: +1 617 927 4500
Fax: +1 617 927 4501
www.nera.com

SUBMITTED BY THE HONORABLE CHARLES MCCONNELL

Impacts of Seven EPA Regulations

Impacts	Scenario 1	Scenario 2	Scenario 3
Annual cost (electric sector)	$15.4 B	$15.0 B	$16.7 B
Peak year cost (electric sector)	$37.1 B	$36.1 B	$44.1 B
Total cost (electric sector, 2013 - 2034)	$203 B	$198 B	$220 B
U.S. average employment loss	590,000/yr	887,000/yr	544,000/yr
U.S. peak year employment loss	Over 700,000	2.2 million	Almost 900,000
Peak loss in Upper Midwest	207,000	455,000	236,000
Peak loss in Miss. Valley	159,000	591,000	155,000
Total coal shutdowns	69,000 MW	69,000 MW	54,000 MW
U.S. average income loss per household	$226/yr	$512/yr	$217/yr
U.S. peak year income loss	$415/family	$723/family	$415/family
Peak loss in Upper Midwest	$685/family	$1,300/family	$650/family
Peak loss in Miss. Valley	$654/family	$1,600/family	$644/family

EXPLANATION

National Economic Research Associates (NERA) analyzed the impacts of seven EPA regulations that affect coal-fired electricity generation: Mercury and Air Toxics Standards (aka Utility MACT rule), regional haze, national ambient air quality standards (NAAQS) for ozone, SO_2 NAAQS, $PM_{2.5}$ NAAQS, 316(b), and coal combustion residuals. The N_{ew}ERA model was used to conduct the analysis. Many of the economic and cost assumptions are taken directly from EPA's analysis and EIA data.

NERA's analysis involved modeling three scenarios. Scenario 1 uses EPA's annualized costs for a revised ozone standard and assumes the costs are incurred beginning in the year in which compliance is required for each nonattainment area. Scenario 2 assumes that EPA's annualized costs for a revised ozone standard are capitalized and incurred before and during the year in which compliance is required for each nonattainment area. Thus, scenarios 1 and 2 bracket the costs of a revised ozone standard of 65 ppb. Scenario 3 assumes natural gas prices that are similar to EIA's low Estimated Ultimate Recovery (EUR) case, which makes the prices from \$0.50/MMBtu to \$1.50/MMBtu higher than EIA's AEO 2012 reference case. The analysis is careful to avoid double counting. For example, emission controls installed to comply with one rule are not counted again in determining the cost of complying with another rule that might require the same emission controls. All dollars are reported by NERA in either 2010\$ or 2012\$. All cumulative impacts, except employment, are present values as of January 2013, calculated at a five percent discount rate.

NERA's analysis does not use worst case assumptions and relies, in most instances, on EIA data and EPA cost estimates. For example, NERA uses EPA costs to model the effects of regulating coal combustion residuals and cooling water intakes (316(b)). Overall, we believe the impacts projected by

NERA are conservative; it is very possible the impacts of these regulations could be more severe than NERA's projections. For example -

- The analysis does not include CSAPR, which has been vacated. If EPA adopts a replacement rule, the impacts projected by NERA could be greater than shown in this analysis.

- The analysis assumes that (1) EPA will regulate coal combustion residuals as non-hazardous waste; (2) EPA will not require the installation of closed cycle cooling at all electric generating facilities; (3) EPA will lower the ozone standard to a level of 65 ppb, rather than a more stringent level; and (4) no further emission reductions from coal-fueled units will be necessary due to EPA's revised SO_2 standard. If EPA adopts regulations that are more stringent than these assumptions (or if the regulations are implemented in a more stringent manner), the impacts will be more severe than NERA's projections.

- The analysis does not include the potential effects of EPA's planned greenhouse gas regulations for existing coal-fired units. EPA has not proposed any such regulations yet but has indicated that it will at some future time.

- The analysis does not consider possible changes to EPA's effluent guidelines for power plant water discharges. EPA has not proposed any changes yet, but is expected to later this year.

- The analysis assumes that all necessary emission controls can be installed by 2016 to comply with MATS without incurring any additional costs due to unusually large demands for labor and materials.

- The modeling does not analyze the potential for electric reliability problems that could be caused by the large number of premature coal unit shutdowns over a short time frame in order to comply with EPA deadlines. Many experts and public officials have raised concerns about electric reliability.

Employment losses caused by the EPA rules take into account the net effect of jobs that are lost (e.g., due to higher energy prices) and jobs that are created (e.g., construction of pollution controls) by these regulations.

Household disposable income is the total amount of money available for spending or saving by a family after taxes have been paid.

The NewERA macroeconomic model includes 11 regions of the U.S. The Upper Midwest region is comprised of Ohio, Michigan, Indiana, Kentucky and West Virginia. The Mississippi Valley region is comprised of Wisconsin, Illinois, Missouri and Arkansas.

October 26, 2012

SUBMITTED BY THE HONORABLE CHARLES MCCONNELL

IMPACT OF EPA REGULATIONS

National Economic Research Associates (NERA) analyzed the impacts of seven EPA regulations that affect coal-fueled electricity generation: MATS, regional haze, ozone NAAQS, SO_2 NAAQS, $PM_{2.5}$ NAAQS, 316(b) and coal combustion residuals. The analysis evaluates three scenarios: two make different assumptions about the timing of ozone compliance costs; the third assumes slightly higher natural gas prices than current projections. The projected economic impacts for all three scenarios are substantial. NERA's analysis does not use "worst case" assumptions. These are some of the highlights of the analysis:

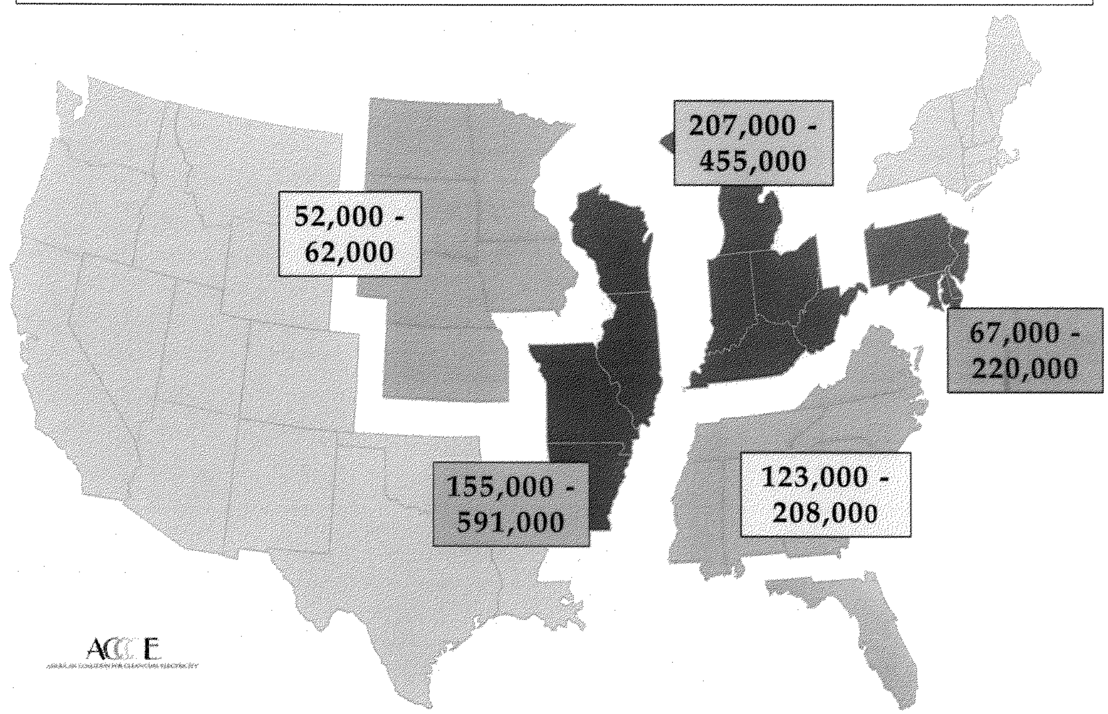
- ✓ **Compliance costs for the electric sector total $198 billion to $220 billion and average $15.0 billion/year to $16.7 billion/year. Peak year compliance costs total $36 billion to $44 billion.**
- ✓ **Coal shutdowns are projected to total 54,000 MW to 69,000 MW, most of which are due to the EPA regulations.**
- ✓ **U.S. employment losses average 544,000/year to 887,000/year. Peak year employment losses are 700,000 to 2.2 million.**
- ✓ **Peak year employment losses range from 354,000 to more than 1 million in regions of the country that include Ohio, Michigan, Missouri, Wisconsin, Illinois and Indiana.**
- ✓ **The average nationwide loss in disposable income varies from more than $200/household to over $300/household. Peak year loss in family income is over $400/household to more than $700/household.**
- ✓ **Peak year loss in family income ranges from $644/household to $1,600/household in regions of the country that include Ohio, Michigan, Missouri, Wisconsin, Illinois and Indiana.**

NERA's 129-page report, *Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector*, provides details on the scenarios, assumptions and other impacts. The report is available at www.cleancoalusa.org.

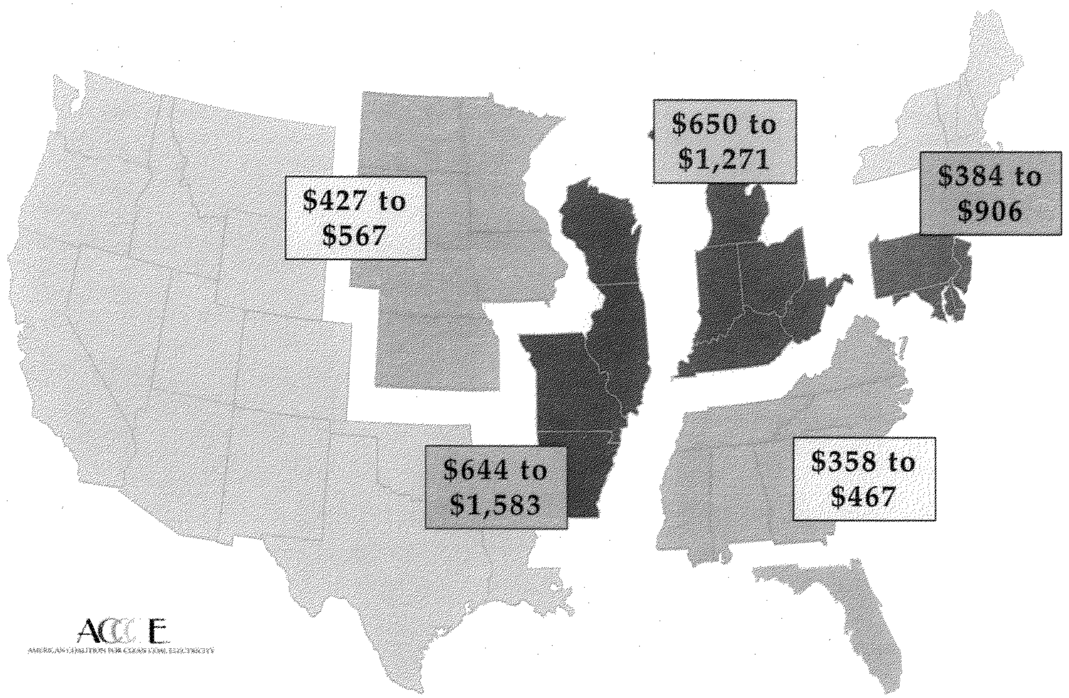
October 26, 2012

Peak Year Employment Losses Caused by EPA Regulations

(Five key regions of the U.S.)

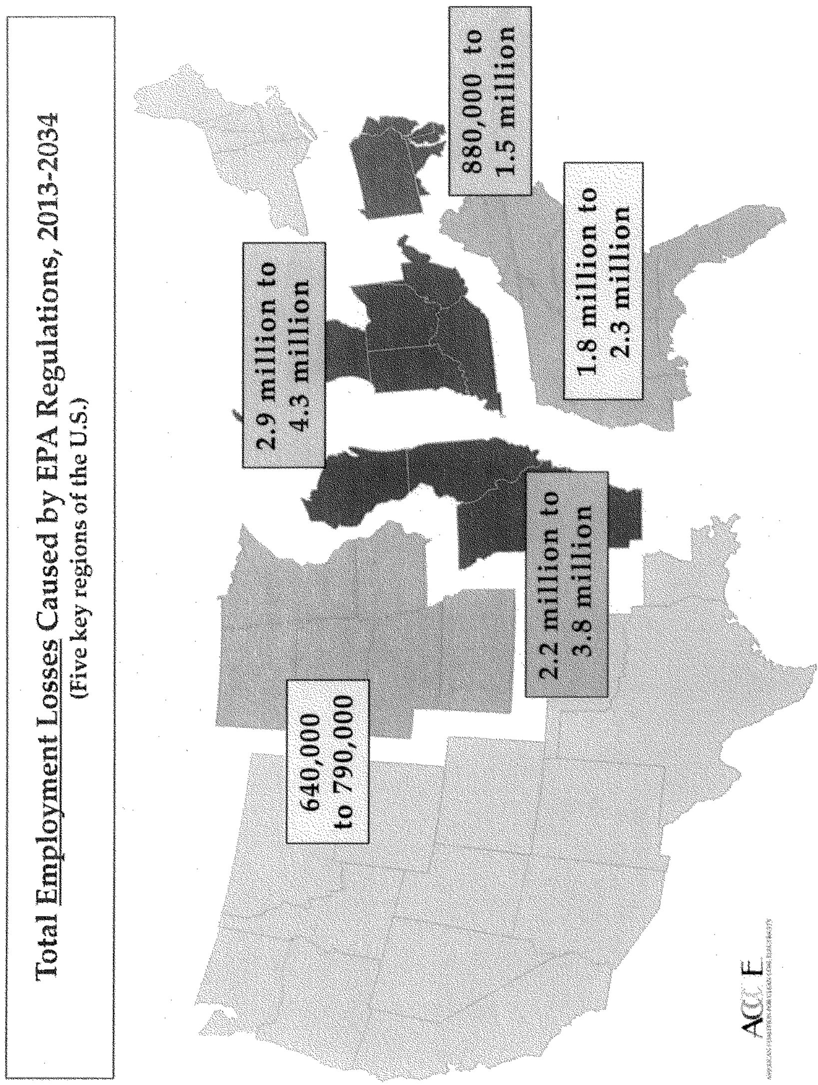


Peak Year Annual <u>Household Income Losses</u> Caused by EPA Regulations
(Five key regions of the U.S.)

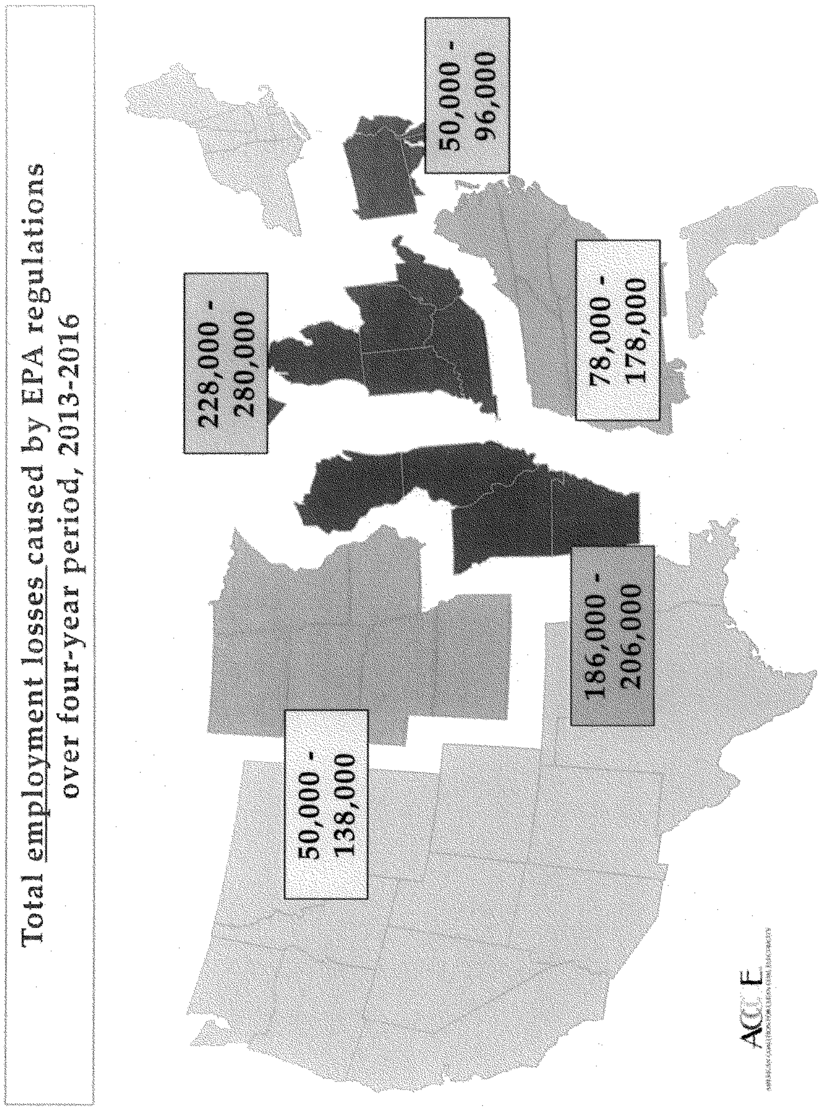


SUBMITTED BY THE HONORABLE CHARLES McCONNELL

SUBMITTED BY THE HONORABLE CHARLES MCCONNELL



SUBMITTED BY THE HONORABLE CHARLES MCCONNELL



○