

**EPA'S CARBON PLAN:
FAILURE BY DESIGN**

HEARING
BEFORE THE
**COMMITTEE ON SCIENCE, SPACE, AND
TECHNOLOGY**
HOUSE OF REPRESENTATIVES
ONE HUNDRED THIRTEENTH CONGRESS

SECOND SESSION

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JULY 30, 2014
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**EPA'S CARBON PLAN:
FAILURE BY DESIGN**

WEDNESDAY, JULY 30, 2014

HOUSE OF REPRESENTATIVES,
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY,
Washington, D.C.

The Committee met, pursuant to call, at 10:07 a.m., in Room 2318 of the Rayburn House Office Building, Hon. Cynthia Lummis [Chairwoman of the Committee] 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

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EPA's Carbon Plan: Failure by Design

Wednesday, July 30, 2014

10:00 a.m.-12:00 p.m.

2318 Rayburn House Office Building

Witnesses

The Honorable Jeffrey Holmstead, Partner, Bracewell & Giuliani LLP

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

Dr. David Cash, Commissioner, Massachusetts Department of Environmental Protection

Mr. Gregory Sopkin, Partner, Wilkinson, Barker, Knauer LLP

**U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY
FULL COMMITTEE**

HEARING CHARTER

EPA's Carbon Plan: Failure by Design

Wednesday, July 30, 2014
10:00 a.m. – 12:00 p.m.
2318 Rayburn House Office Building

PURPOSE

The Committee on Science, Space, and Technology will hold a hearing entitled *EPA's Carbon Plan: Failure by Design* on Wednesday, July 30th, in Room 2318 of the Rayburn House Office Building. The hearing will examine the Environmental Protection Agency's (EPA) approach to implementing technology-based standards under section 111 of the Clean Air Act (CAA). In so doing, the hearing will examine the scientific methods employed by EPA to calculate each state's specific carbon-reduction goal; the technologies available to meet EPA's standards for fossil-fuel power plants; and technical challenges to implement EPA's carbon plan.

WITNESS LIST

- **The Honorable Jeffrey Holmstead**, Partner, Bracewell & Giuliani LLP
- **The Honorable Charles McConnell**, Executive Director, Energy & Environment Initiative, Rice University
- **Dr. David Cash**, Commissioner, Massachusetts Department of Environmental Protection
- **Mr. Gregory Sopkin**, Partner, Wilkinson, Barker, Knauer LLP

BACKGROUND

Following the Supreme Court's 5-4 decision in *Massachusetts v. EPA*,¹ the Agency promulgated numerous standards and proposed rules aimed at reducing greenhouse gas (GHG) emissions. These include EPA's:

- **2009 Endangerment Finding**, where "EPA determined that greenhouse gases endanger the health and welfare of Americans;"²

¹ *Massachusetts v. U.S. Environmental Protection Agency*, 549 U.S. 497 (2007) available at <http://www.supremecourt.gov/opinions/06pdf/05-1120.pdf>.

² U.S. ENVIRONMENTAL PROTECTION AGENCY. "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act; Final Rule." Dec. 2009. Available at <http://www.gpo.gov/fdsys/pkg/FR-2009-12-15/pdf/E9-29537.pdf>.

- *Light Duty Vehicle Rule*, in which “EPA coordinated with the National Highway Traffic Safety Administration to develop harmonized regulations to reduce greenhouse gas emissions and improve the fuel economy of light-duty vehicles;”³ and
- *Tailoring Rule*, where “EPA set greenhouse gas emission thresholds to define when permits under the New Source Review Prevention Significant Deterioration (PSD) and title V Operating Permit programs are required for new and existing industrial facilities.”⁴

Climate science—and regulatory actions informed by such science—are among the most complex and controversial issues facing policymakers. President Obama has increasingly signaled his intention to propose significant, new executive actions and regulatory measures aimed at addressing climate concerns.⁵

According to EPA, power plants are the Nation’s largest source of carbon pollution and “account for roughly one-third of all domestic greenhouse gas emissions in the United States.”⁶ (See Figure 1) On June 25, 2013 President Obama directed the Environmental Protection Agency (EPA) to regulate greenhouse gas emissions from new and existing power plants.⁷

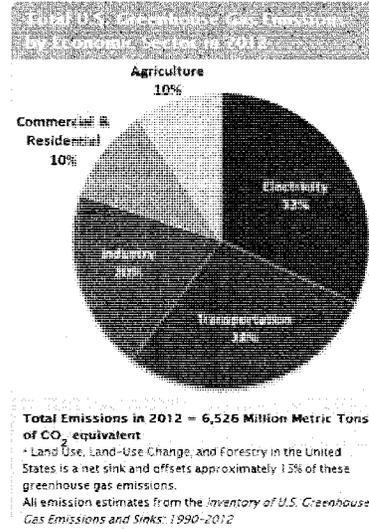


Figure 1. Source: U.S. EPA Available at <http://www.epa.gov/climatechange/pghgmissions/sources.html>

REGULATORY CONTEXT

Section 111 of the Clean Air Act (CAA) establishes a unique technology-based mechanism for controlling emissions from “stationary sources” (i.e., power plants). Section 111 provides authority for EPA to promulgate standards 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

³ U.S. ENVIRONMENTAL PROTECTION AGENCY. “Light-Duty Vehicle Greenhouse Gas Emissions Standards and Corporate Average Fuel Economy Standards; Final Rule.” May 2010. Available at <http://www.epa.gov/fdsys/pkg/FR-2010-05-07/pdf/2010-8159.pdf>.

⁴ See e.g. U.S. Environmental Protection Agency. “Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule Step 3 and GHG Plant wide Applicability Limits; Final Rule” July 2012. Available at <http://www.epa.gov/fdsys/pkg/FR-2012-07-12/pdf/2012-16704.pdf>.

⁵ See: <http://www.whitehouse.gov/the-press-office/2013/06/25/remarks-president-climate-change> and <http://www.whitehouse.gov/climate-change> for examples.

⁶ <http://yosemite.epa.gov/opa/admpress.nsf/bd4379a92ceceac8525735900400c27/5bb6d20668b9a18485257ceb00490c98!OpenDocument>

⁷ THE WHITE HOUSE, “The President’s Climate Action Plan,” June 2013. Available at <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>

account the cost. . .) the Administrator determines has been adequately demonstrated.”⁸ 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.”⁹

Section 111 lays out different approaches for new and existing sources. Under Section 111(b), the EPA has the authority to develop a “federal program to address new, modified and reconstructed sources by establishing standards of performance.”¹⁰ In contrast, EPA explains that “section 111(d) of the Act requires states to develop plans for *existing* sources of noncriteria pollutants (i.e., a pollutant for which there is no national ambient air quality standard) whenever EPA promulgates a standard for a new source.”¹¹

New Power Plants

EPA first proposed a New Source Performance Standards (NSPS) for emissions for carbon dioxide (CO₂) from power plants in April 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.¹² Consequently, on September 20, 2013 Administrator Gina McCarthy announced EPA’s re-proposed CO₂ NSPS for new fossil fuel-based electric generating units (EGUs).

Under EPA’s NSPS proposal, the Agency concluded that Carbon Capture and Storage (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 lb CO₂/MWH and proposed standards for natural gas combined cycle sources from 1,000 to 1,100 lb CO₂/MWH depending on the size and type of unit. EPA did not include modified and reconstructed plants in the proposed rule. EGUs that primarily fire biomass are exempted from the proposed rule.¹³ Find more information on CCS and EPA’s carbon rules in hearing held last March: <http://science.house.gov/hearing/subcommittee-energy-and-subcommittee-environment-joint-hearing-science-capture-and-storage>.

Existing Power Plants

On June 2, 2014, EPA issued its “Clean Power Plan” under section 111(d), which addressed carbon emissions from existing fossil-fueled power plants. EPA explains the key difference between section 111(d), for existing power plants, and 111(b) for new and modified plants: “Section 111(d)’s mechanism for regulating existing sources differs from the one that

⁸ Clean Air Act § 111(a)(1), 42 USCA § 7411(a)(1) (2006).

⁹ <http://www2.epa.gov/sites/production/files/2013-09/documents/111background.pdf>

¹⁰ <http://www2.epa.gov/sites/production/files/2013-09/documents/20130920technicalfactsheet.pdf>

¹¹ <http://www.epa.gov/Region7/air/rules/111d.htm>.

¹² Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Proposed Rule, Preamble p. 14-5, Sep. 20, 2013. Found at:

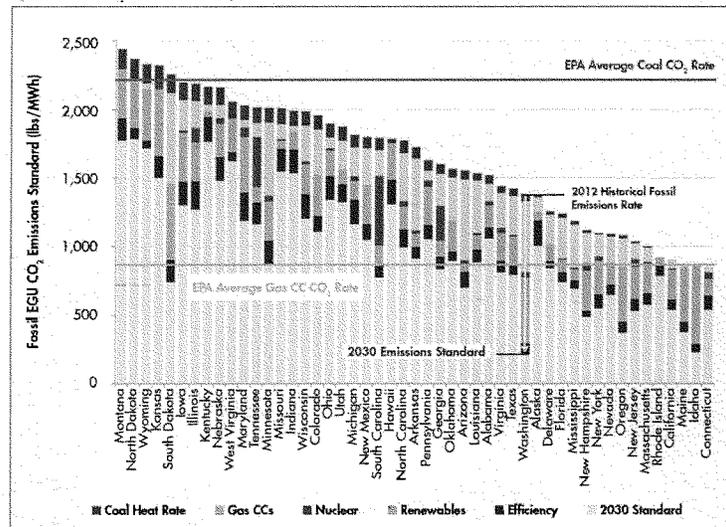
<https://www.federalregister.gov/articles/2014/01/08/2013-28668/standards-of-performance-for-greenhouse-gas-emissions-from-new-stationary-sources-electric-utility#h-18> (Is this the right link for this citation?)

¹³ *Id.* at 30, fn. 8.

CAA section 111(b) provides for new sources because CAA section 111(d) contemplates states submitting plans that establish ‘standards of performance’ for the affected sources and that contain other measures to implement and enforce those standards.”¹⁴

The Agency believes the proposed Clean Power Plan will “lower the carbon intensity of power generation in the United States by approximately 30% in 2030 from carbon dioxide emissions levels in 2005. The agency predicts that under the Clean Power Plan, electricity bills will decline by “roughly 8 percent”¹⁵ and that the amount of U.S. electricity generated by coal-fired EGUs will decline by at least 25%. To achieve this goal, EPA is giving each state a numerical carbon reduction target, based on the state’s existing power generation portfolio.”¹⁶ (See Figure 2.)

Figure 2: Fossil EGU CO₂ emissions standards by state



Source: The Brattle Group

Specifically, EPA set each state’s required level of carbon reduction assuming that each state could recognize a set level of carbon reductions through the use of four “building blocks.” Broadly speaking, the four blocks encompass:¹⁷

¹⁴ U.S. ENVIRONMENTAL PROTECTION AGENCY, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, 79 FR 34832, June 2, 2014.

¹⁵ <http://yosemite.epa.gov/opa/admpress.nsf/bd4379a92ceceac8525735900400c27/5bb6d20668b9a18485257ceb00490c98!OpenDocument>

¹⁶ CONGRESSIONAL RESEARCH SERVICE, *EPA’s Proposed Greenhouse Gas Regulations: Implications for the Electric Power Sector*. June 23, 2014. Available at: <http://www.crs.gov/pdfloader/R43621>.

¹⁷ U.S. ENVIRONMENTAL PROTECTION AGENCY, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, 79 FR 34832, June 2, 2014.

1. Installing technologies to increase efficiency at power plants.
2. Giving Natural Gas Combined-Cycle plants priority over steam-boilers.
3. Building new renewable power generation.
4. End-user efficiency technologies and programs that reduce power demand.

EPA proposes that these building blocks represent the “best system of emissions reduction” that has been adequately demonstrated for fossil-fuel power plants regulated under the EPA rule.

According to EPA, the proposed rule will be “implemented through a state-federal partnership under which states identify a path forward using either current or new electricity production and pollution control policies to meet the goals of the proposed program. The proposal provides guidelines for states to develop plans to meet state-specific goals to reduce carbon pollution and gives them the flexibility to design a program that makes the most sense for their unique situation.”¹⁸

Modified Power Plants

On the same day as the 111(d) “Clean Power Plan,” EPA also unveiled a separate 111(b) “Modified Source Proposal,” in which EPA explained:

*For more than four decades, the EPA has used its authority under CAA section 111 to set cost-effective emission standards that ensure newly constructed, reconstructed and modified stationary sources use the best performing technologies to limit emissions of harmful air pollutants. In this proposal, the EPA is following the same well-established interpretation and application of the law under CAA section 111 to address GHG emissions from modified and reconstructed fossil fuel-fired electric steam generating units and natural gas-fired stationary combustion turbines.*¹⁹

The proposed rule for Modified Sources only applies to fossil-fueled power plants that undergo major modifications or reconstruction. In contrast with the broad approach EPA utilized for existing power plants, this proposal identifies a “combination of best operating practices and equipment upgrades” as the “best system of emission reduction” and arrives at a unit specific standard requiring 2% efficiency gains.

ADDITIONAL READING

CONGRESSIONAL RESEARCH SERVICE. *Climate Change and Existing Law: A Survey of Legal Issues Past, Present, and Future*. March 10, 2014. Available at <http://www.crs.gov/pdfloader/R42613>.

¹⁸<http://yosemite.epa.gov/opa/admpress.nsf/bd4379a92ceceac8525735900400c27/5bb6d20668b9a18485257ceb00490c98!OpenDocument>.

¹⁹ U.S. ENVIRONMENTAL PROTECTION AGENCY. “Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units; Proposed Rule.” June 2014. Available at <http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13725.pdf>.

- CONGRESSIONAL RESEARCH SERVICE. *EPA's Proposed Greenhouse Gas Regulations: Implications for the Electric Power Sector*. June 23, 2014. Available at <http://www.crs.gov/pdfloader/R43621>.
- CONGRESSIONAL RESEARCH SERVICE. *EPA's Proposed Greenhouse Gas Regulations for Existing Power Plants: Frequently Asked Questions*. July 3, 2014. Available at <http://www.crs.gov/pdfloader/R43572>.
- U.S. ENVIRONMENTAL PROTECTION AGENCY. *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule. 79 FR 34832. June 2014. Available at <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule>.
- U.S. ENVIRONMENTAL PROTECTION AGENCY. *Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units*, Proposed Rule. 79 FR 34960. June 2014. Available at <http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13725.pdf>.
- U.S. ENVIRONMENTAL PROTECTION AGENCY. *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule. 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 LUMMIS. Good morning. The Committee on Science, Space, and Technology will come to order.

Welcome to today's hearing titled "EPA's Carbon Plan: Failure by Design." In front of you are packets containing the written testimonies, biographies, and truth-in-testimony disclosures for today's witnesses.

And without further ado, I now recognize myself for five minutes for an opening statement.

Today, we are examining one of the most sweeping regulatory proposals in American history. The EPA is attempting to take control of our nation's electric system without legal or scientific justification. The EPA's Clean Power Plan reaches well beyond the regulation of power plants. The EPA wants to control the entire system, right down to the amount of electricity Americans use in their homes.

The implications of this overreach really are staggering. The rule has the potential to shut down power plants across the Nation, raise energy prices, and threaten energy security. And I submit for what? The EPA admits that the rule will have little or no impact on global warming. In this case it appears to be regulation in the name of climate change but it is just regulation in the name of regulation, Federal control for Federal control's sake.

EPA's proposal would impose standards on States that turn power systems on their heads. Each State's reduction mandate varies widely, based on what the EPA claims can be done through a combination of costly efficiency technologies, drastic fuel switching, and unprecedented reliance on intermittent renewables and energy rationing.

States, companies, and utility commissioners and local officials are left figuring out how to comply, which will necessarily involve higher prices and potentially threaten grid reliability. The EPA claims the rule is flexible and that compliance is easy. But the EPA's assurances are of little comfort when the standards are beyond what technology can deliver and ratepayers can afford.

The ability of the EPA's so-called building blocks, which are really mandates, to produce the required reductions is uncertain. The limited analysis in this rule is based on black box models and untested assumptions. This hides the hard fact that ratepayers will be left holding the bag on an expensive overhaul of our electric system to reach theoretical and unproven targets.

The confusion also hides a more fundamental concern. The EPA is operating outside the bounds of the law. The Clean Air Act does not give the EPA the authority to regulate the electric grid or tell Americans where to set their thermostat. Instead, EPA is limited to technology-based standards at the power plants themselves.

As our witnesses will explain, had EPA followed the law and been straightforward about what technology can accomplish, the rule might be manageable. But since the law doesn't match this Administration's agenda, the EPA is now bypassing Congress to rewrite the statute. The EPA also ignores technology and reliability concerns. The Administration hasn't fully considered the potential impacts of this proposal on the electric system, the economy, and the American people most importantly.

A scientific look at the proposal reveals major problems. EPA's claims are backed by flawed technology assumptions. It relies on unrealistic scenarios about our nation's energy future. And EPA's conclusions are based on a secret model, hidden from public view. We see this all too often at EPA. In fact, serving on Natural Resources Committee and other natural resource matters, we see it all the time in this natural resource environment that we are in with this Administration.

This science that is hidden science undermines the scientific review process and moves straight to regulation. The law requires a bottom-up review of what can be accomplished at a power plant. Instead, the EPA has proposed top-down regulation of the entire electric system. This rule needs to be withdrawn. It fails to meet even the most basic standards of objectivity and transparency; it lacks technical analysis on scientific and economic feasibility, and the American people deserve to know exactly what the EPA is doing, and that is why we are having this hearing today. Other than that, my constituents have no strong feelings about this.

[The prepared statement of Mrs. Lummis follows:]

PREPARED STATEMENT OF SUBCOMMITTEE ON ENERGY CHAIRMAN CYNTHIA LUMMIS

Today, we examine one of the most sweeping regulatory proposals in America's history. The Environmental Protection Agency (EPA) is continuing its regulation rampage, attempting to take control of our nation's electric system without any legal or scientific justification.

The EPA's "Clean Power Plan" reaches well beyond just the regulation of power plants. The EPA wants to control the entire system, right down to the amount of electricity Americans use in their homes.

The implications of this overreach are staggering. The rule has the potential to shut down power plants across the nation, raise energy prices and threaten energy security. And for what? Even EPA admits that the rule will have little to no impact on global warming.

EPA's proposal would impose standards on states that turn their power systems on their heads. Each state's reduction mandate varies widely, based on what EPA claims can be done through a combination of costly efficiency technologies, drastic fuel switching, and unprecedented reliance on intermittent renewables and energy rationing.

States, companies, utility commissioners and local officials are left figuring out how to comply, which will necessarily involve higher prices and potentially threaten grid reliability. The EPA claims the rule is flexible, and that compliance is easy. But EPA's assurances are of little comfort when the standards are beyond what technology can deliver.

The ability of the EPA's "building blocks," which might as well be called mandates, to produce the required reductions is uncertain at best. The limited analysis in this rule is based on black box models and untested assumptions. This hides the hard fact that states will be left holding the bag on an expensive overhaul of our electric system to reach theoretical and unproven targets.

The confusion also hides a more fundamental concern: the EPA is operating outside the bounds of the law. The Clean Air Act does not give the EPA the authority to regulate the electric grid or tell Americans where to set their thermostat. Instead, EPA is limited to technology-based standards at the power plants themselves.

As our witnesses will explain, had EPA followed the law and been honest about what technology can accomplish, the rule might be manageable. But since the law doesn't match the President's partisan agenda, the EPA is now bypassing Congress to rewrite the statute. This comes as no surprise from this Administration. The EPA also ignores technology and reliability concerns. The Administration hasn't fully considered the potential impacts of this proposal on the electric system, the economy and the American people.

A scientific look at the proposal reveals major problems. EPA's claims are backed by flawed technology assumptions. It relies on unrealistic scenarios about our na-

tion's energy future. And EPA's conclusions are based on a secret model, hidden from public view.

Instead of providing useful tools for state and local policymakers, the analysis appears to be nothing more than window-dressing for a predetermined outcome.

We see this all too often at the EPA. It undermines the scientific review process and moves straight to regulation. The law requires a bottom-up review of what can be accomplished at a power plant. Instead, the EPA has proposed top-down regulation of the entire electric system.

This rule needs to be withdrawn. It fails to meet even the most basic standards of objectivity and transparency; and it lacks technical analysis on scientific and economic feasibility. The American people deserve to know exactly what the EPA is doing, and that is why we are having this hearing today.

Chairman LUMMIS. That is my opening statement and now I would like to recognize the Ranking Member, the gentlewoman from Texas, Mrs. JOHNSON, for an opening statement.

Ms. JOHNSON. Thank you very much, Madam Acting Chair. And let me thank our witnesses for being here this morning.

Last month, the Environmental Protection Agency released its Clean Power Plan, a proposal to cut carbon pollution from the largest source, power plants. This proposal, like the rest of President Obama's Climate Action Plan, is the bold step forward our nation needs to address the impacts of climate change—impacts that are growing more present in the lives of every American.

Severe drought, record temperatures, and an increase in the spread of infectious diseases are just a few examples of what Americans will have to confront in the coming years. The scientific evidence confirms that we need to act now to lessen these impacts. Cutting carbon emissions from the power sector is critical to any solution that is—and that is why I support the Clean Power Plan. It sets reasonable limits that take into account the characteristics of each State. It is based on strategies already in use such as improving energy efficiency and power plant operations and encouraging the development of renewables. And finally, it provides the States with flexibility.

EPA is not prescribing a specific set of measures. States will choose what goes into their plans and they can work alone or as part of a multistate effort to achieve meaningful reductions. Today, we will hear from some Members and witnesses that EPA is acting beyond its authority and that EPA regulations are killing the economy and jobs.

This is not a new argument but one that we have heard time and time again. Whenever EPA proposes an action that will protect the air we breathe and the water we drink, industry raises alarms about the purported negative impact on the economy. I expect we will hear the same argument trotted out once again in today's hearing.

In addition, some of my colleagues on the other side of the aisle are fond of saying that those who want to address climate change are alarmists using scare tactics to frighten the American people. I would say that the true alarmists are those who have a history of exaggerating the cost of compliance. For example, in 1990, electric utilities opposed to the Acid Rain Program said that the cost of an allowance to emit sulfur dioxide would be \$1,500 per ton. It in fact turned out to be \$150 per ton.

Madam Chair, I could go on but the track record of Clean Air Act speaks for itself. Since its adoption in 1970, air pollution has de-

clined more than 70 percent and the American economy has more than tripled. Now more than ever the American people need a strong EPA. I firmly believe that we can have a vibrant economy and a safe and healthy environment. The Clean Power Plan puts us on the path to achieving both.

Thank you. And before I yield back, I would like to request that Mr. Kennedy be allowed to introduce Dr. Cash.

Thank you. I yield back.

[The prepared statement of Ms. Johnson follows:]

PREPARED STATEMENT OF RANKING MEMBER EDDIE BERNICE JOHNSON, COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY

Thank you, Mr. Chairman, and thank you to our witnesses for being here this morning. Last month, the Environmental Protection Agency released its Clean Power Plan, a proposal to cut carbon pollution from the largest source—power plants.

This proposal like the rest of President Obama’s Climate Action Plan, is the bold step forward our nation needs to address the impacts of climate change. Impacts that are growing more present in the lives of every American. Severe drought, record temperatures, and an increase in the spread of infectious disease are just a few examples of what Americans will have to confront in the coming years.

The scientific evidence confirms that we need to act now to lessen these impacts. Cutting carbon emissions from the power sector is critical to any solution and that is why I support the Clean Power Plan. It sets reasonable limits that take into account the characteristics of each state. It is based on strategies already in use such as improving energy efficiency and power plant operations, and encouraging the development of renewables. And finally, it provides the states with flexibility; EPA is not prescribing a specific set of measures. States will choose what goes into their plans and they can work alone or as part of a multi-state effort to achieve meaningful reductions.

Today we will hear from some Members and witnesses that EPA is acting beyond its authority, and that EPA regulations are killing the economy and jobs.

This is not a new argument, but one that we have heard time and time again. Whenever, EPA proposes an action that will protect the air we breathe or the water we drink, industry raises alarms about the purported negative impact on the economy. I expect we will hear the same argument trotted out again at today’s hearing.

In addition, some of my colleagues on the other side of the aisle are fond of saying that those who want to address climate change are alarmists, using “scare tactics” to frighten the American people. I would say that the true alarmists are those who have a history of exaggerating the cost of compliance. For example, in 1990, electric utilities opposed to the acid rain program said the cost of an allowance to emit sulfur dioxide would be \$1,500 per ton. It, in fact, turned out to be \$150 per ton.

Mr. Chairman, I could go on, but the track record of the Clean Air Act speaks for itself. Since its adoption in 1970, air pollution has declined by more than 70 percent and the American economy has more than tripled. Now, more than ever, the American people need a strong EPA. I firmly believe we can have a vibrant economy and a safe and healthy environment. The Clean Power Plan puts us on the path to achieving both.

Thank you and I yield back.

Chairman LUMMIS. Mr. Kennedy, we will—when we reach Dr. Cash’s introduction, I will yield to you at that time. Thank you.

Mr. KENNEDY. Thank you, Madam Chair. Thank you, Ranking Member.

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

Chairman LUMMIS. At this time I would like to introduce our witnesses. Our first witness today is Mr. Jeff Holmstead. Mr. Holmstead is one of the Nation’s leading air quality lawyers and heads the Environmental Strategies Group at Bracewell and—how

do you pronounce it—Giuliani. Okay. He previously served as Assistant Administrator at the EPA for the Office of Air and Radiation. He also served on the White House staff as Associate Counsel to former President George H.W. Bush. Mr. Holmstead received his law degree from Yale.

Our second witness is Charles McConnell, Executive Director at the Energy & Environment Initiative at Rice University. Previously, Mr. McConnell served as the Assistant Secretary for Fossil Energy at the U.S. Department of Energy. At DOE he was responsible for the strategic policy leadership budgets, project management, and research and development of the Department's Coal, Oil, Gas Advanced Technology Programs and the National Energy Technology Labs. He received his bachelor's degree in chemical engineering from Carnegie Mellon and an MBA from Cleveland State.

And now to introduce Dr. David Cash, I will yield to the gentleman from Massachusetts, Mr. Kennedy.

Mr. KENNEDY. Thank you, Madam Chairman.

We are here today in part to examine how States can be empowered to use an innovative approach to successfully navigate the challenges they confront. To that end, I am delighted to welcome Dr. Cash, a constituent and Commissioner of the Massachusetts Department of Environmental Protection.

Throughout his career in public service, Dr. Cash has played an integral role in our Commonwealth's efforts to address climate change, first, as the Under Secretary for Policy in the Massachusetts Executive Office of Energy and Environmental Affairs, then as Commissioner at the Massachusetts Department of Public Utilities. He has been a leader in developing a Massachusetts Clean Energy and Climate Plan for 2020 and other legislation that will reduce the State's greenhouse gas emissions, legislation that has contributed to a 16 percent statewide drop in emissions since 1990. Beyond the success we have experienced in limiting emissions, these initiatives have also led to an 11.8 percent increase in clean tech job growth in the last year.

Dr. Cash, as Congresswoman Clark and I often cite the success of Massachusetts to others in this room, we are very happy to have you here today and look forward—I am looking forward to your testimony.

Thank you, Madam Chairman. I yield back.

Chairman LUMMIS. I thank the gentleman from Massachusetts.

Our final witness today is Mr. Gregory Sopkin, Partner at Wilkinson Barkett and Knauer—what is it? Barker?

Mr. SOPKIN. Barker.

Chairman LUMMIS. Okay.

Mr. SOPKIN. Thank you.

Chairman LUMMIS. Got a typo here. Previously, Mr. Sopkin was the Chairman of the Colorado Public Utilities Commission, a neighbor here. Thanks. I am from Wyoming.

He has also worked as Assisting Attorney General for Colorado. He has practiced energy and telecommunications law for over 15 years and has been a member of the National Association of Regulatory Utility Commissioners. Mr. Sopkin received his law degree from the University of Colorado.

As our witnesses should know, spoken testimony is limited to five minutes after which the Members of the Committee will have five minutes each to ask questions.

I now recognize our first witness, Mr. Holmstead, for five minutes. Welcome.

**TESTIMONY OF THE HONORABLE JEFFREY HOLMSTEAD,
PARTNER, BRACEWELL & GIULIANI LLP**

Mr. HOLMSTEAD. Thank you and good morning. I thank you very much for giving me the chance to testify this morning.

There is a lot to say about EPA's proposal, but this morning, I would like to focus on just two major points. First, anyone who believes in the rule of law should be troubled by EPA's proposal. It goes far beyond the authority that Congress has given to the agency.

And second, EPA officials have and so distracted with the notion that they can fundamentally change the electric system in 49 States that they have failed to do the basic technical work that they are supposed to do to develop legally defensible regulations to reduce carbon emissions from existing power plants.

The Supreme Court has made it clear that EPA has authority to regulate carbon emissions under the Clean Air Act but the Supreme Court has not given EPA a roving mandate to do whatever it thinks best when it comes to regulating those emissions. In the Clean Air Act Congress created literally dozens of different regulatory programs with carefully defined limits. Some of these programs can be used to regulate carbon emissions, but EPA may only do so in a way that complies with the limits established by Congress.

EPA has proposed to use Section 111(d) to regulate carbon emissions from existing power plants. There is a significant question about whether they can even use that provision, but I want to set that aside and ask the question if EPA can regulate carbon emissions from existing power plants under Section 111(d), what would those regulations look like?

And it has been interesting to me. There is all this debate about this proposal and few people ever actually look at what the statute says. So let me quote from the relevant provisions of the statute. It says that "EPA can require a State to develop a plan that includes a standard of performance that requires a continuous emission reduction for any existing power plant in their State based on the best system of emission reduction that has been adequately demonstrated for that type of plant but that States shall be permitted in applying the standard of performance to any particular source to take into consideration, among other factors, the remaining useful life of the existing plant to which such standard applies." That is just what the statute says, and what EPA has done for 37 years under that regulation is to establish an allowable emission rate that each plant would have to meet.

But somehow, EPA has discovered a broad new power from these words, a broad new power in a provision that has been in place for almost 40 years. After all this time, it turns out that this provision actually gives EPA the authority to require States to fundamen-

tally change the way that electricity is generated and used throughout their States.

Here is what EPA expects States to do: first, require all existing coal-fired power plants to improve their efficiency by an average of six percent regardless of how efficient they are today or whether it is technically feasible to improve their efficiency by that much. But at least that is close to the statute.

Second, they want to be States to take business away from these more efficient coal plants and give this business to the gas-fired power plants in the State until the gas-fired plants are operating at 70 percent capacity regardless of the cost or whether these gas-fired plants were even designed to operate that much.

Third, EPA believes that it can require States to mandate more wind and solar power plants be constructed and used.

And fourth, to come up with programs to require people and industries to use less electricity so that the total statewide demand for electricity is reduced by 1.5 percent a year every year for 10 years.

All these things, according to EPA, can be required under a statutory provision that says the following: "EPA can require States to set a standard of performance for any existing power plant in their States but that a State must be permitted in applying a standard of performance to any particular plant to consider the remaining useful life of that plant."

Simply put, EPA's reading is preposterous. And because the folks at EPA have been so distracted by the notion that they can change the electric power system in our country, they have failed to do the basic technical work they are supposed to do under the Clean Air Act. What they are supposed to do is actually go out and study existing power plants to determine the lowest carbon emission rates that have been achieved by different types of plants based on size, boiler type, age, and other factors and then provide technical guidance to the States so that the state environmental officials have the information they need to go out and set appropriate emission standards for the plants in their States. The sooner EPA does what it is actually supposed to do, the sooner we will have a defensible program to reduce carbon emissions from existing power plants.

Thank you and I would be happy to answer any questions you may have.

[The prepared statement of Mr. Holmstead follows:]

**Testimony of Jeffrey R. Holmstead
before the
U.S. House Committee on
Science, Space, and Technology
July 30, 2014**

Thank you Chairman Smith, Ranking Member Johnson, and distinguished members of the Committee for inviting me to participate in today's hearing.

My name is Jeff Holmstead. I am a partner in the law firm of Bracewell & Giuliani and have been the head of the firm's Environmental Strategies Group (ESG) since 2006. For almost 25 years, my professional career has been focused on policy, regulatory, and legal issues arising under the Clean Air Act. From 1989 to 1993, I served in the White House Counsel's Office as Associate Counsel to President George H.W. Bush. In that capacity I was involved in many of the discussions and debates that led to the passage of the 1990 Amendments to Clean Air Act – and was then deeply involved in the initial efforts to implement those Amendments. From 2001 to 2005, I was the Assistant Administrator of EPA for Air and Radiation and headed the EPA Office in charge of implementing the Clean Air Act. I am well acquainted with the legal, policy, and practical issues associated with the Clean Air Act and efforts to regulate carbon and other greenhouse gases under the Act.

I am pleased to come before you today to discuss the EPA's proposal to regulate carbon dioxide emissions from existing power plants. There is much to say about this proposal, but I will focus on 2 main concerns: (1) EPA's proposal goes well beyond its legal authority under the Clean Air Act by trying to force states to regulate anything that produces or uses electricity; and (2) EPA has been so distracted by the notion that it can fundamentally change the electricity system in all 50 states that it has not done the technical work needed to develop legally sound regulations to reduce carbon emissions from existing fossil fuel power plants.

At the outset, I want to note an important issue that I will not address in any detail. EPA proposes to regulate existing power plants under Section 111(d) of the Clean Air Act. Given that it has already regulated power plants under Section 112, there are significant legal questions as to whether EPA has authority to regulate power plants at all under Section 111(d). Attorneys General in many states, along with many other parties, have already raised this issue, and the courts may well decide that EPA is precluded from issuing any type of power plant regulation under Section 111(d). In today's testimony, however, I will assume that EPA does have authority to use 111(d) to regulate carbon emissions from power plants and will focus only on the type of regulation that is legally permissible under Section 111(d).

EPA's Authority to Regulate GHGs under the Clean Air Act

The Supreme Court has made it clear that EPA has authority to regulate carbon dioxide (CO₂) and other greenhouse gases (GHGs) under the Clean Air Act (CAA). But the Supreme Court has not given EPA a roving mandate to do whatever it thinks best when it comes to regulating greenhouse gases. In the CAA, Congress created a number of different regulatory programs with

carefully defined limits. Some of these programs can be used to regulate greenhouse gases, but EPA may only do so in a way that complies with the limits established by Congress.

A recent Supreme Court decision makes this point quite clearly. On June 23rd, the Court issued its decision in *Utility Air Regulatory Group v. Environmental Protection Agency (UARG v. EPA)*. In that case, the Court overruled EPA's determination that emissions of CO₂ and other GHGs trigger certain CAA permitting requirements. Although the Court did allow EPA to require GHG permit limits for projects that must have permits for conventional pollutants, it reminded EPA that the Agency does not have unfettered authority to regulate carbon emissions in any way the Agency might want. Instead, the Court ruled that EPA must craft regulations that are consistent with the statutory language of the CAA.

Section 111 of the Clean Air Act

Section 111, in essentially its current form, has been in place since 1977, and anyone who works on CAA issues is familiar with it. Before issuing any type of regulation under Section 111, EPA must first identify specific types of facilities (which are generally known as "sources" under the CAA) that, in EPA's judgment, emit air pollution that endangers public health. As part of this process, EPA creates "source categories" and carefully defines the type of facilities that fall within these categories.

For power plants (and other types of sources as well), EPA has also created "subcategories" to reflect the fact that there are different types of power plants – traditional coal-fired plants, plants known as IGCC plants that burn gasified coal, combined-cycle natural gas plants, and simple-cycle natural gas plants. Sometimes there are different subcategories for different sizes of the same type of plant. These subcategories are important because the best system for controlling emissions can be quite different for different types of plants. More importantly, the emission rate that can be achieved with these systems can vary greatly for different types of plants. For ease of explanation, I will use "category" to refer to both categories and subcategories.

Once EPA has defined a category, it then develops, under Section 111(b), a "standard of performance" for a particular pollutant. Once such a standard is issued, any new facility that falls within the defined category must comply with it. These standards are often called "new source performance standards" or NSPS. The CAA air includes two different but complementary definitions of the term "standard of performance," and any EPA regulation must comply with both of them.

Section 111(a): The term "standard of performance" means 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.

Section 302(l): "The term "standard of performance" means a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction."

As a shorthand, CAA practitioners often refer to the first definition as BSER, because a standard of performance must reflect the application of the “best system of emission reduction” (BSER) to sources that fall within the category being regulated.

Under Section 111(b), EPA has set dozens of different “standards of performance” by identifying the BSER that can be applied to the types of facilities included in the regulated category. As noted above, these standards are generally set as an emission rate that can be achieved by the use of BSER, and any new facility in the category must meet them. EPA has recently used Section 111(b) to propose standards of performance for CO₂ emissions from different types of new fossil fuel power plants. As proposed, these standards would establish an allowable emission rate in terms of CO₂ emissions per MMBtu – in essence, an allowable amount of CO₂ per unit of electricity produced. If these standards are finalized and upheld in court, then any new coal- or gas-fired power plant must meet the standard of performance that applies to that particular type of plant.

Section 111(d) comes into play only after EPA has set a standard of performance for new plants in a source category under Section 111(b) – and only for pollutants that are not regulated as either “criteria pollutants” or “hazardous air pollutants” under other parts of the CAA. (As noted above, EPA may be precluded from using Section 111(d) for any source category that is regulated under Section 112, but I am assuming that this is not the case for now.) Because virtually all pollutants are regulated as either criteria or hazardous air pollutants, Section 111(d) has only been used five times before, but the key term in section 111(d) is the same as the key term in Section 111(b) -- and is a term that EPA has interpreted consistently (with one exception in a regulation that was vacated in court) for almost 40 years. Here is what it says:

The Administrator [of EPA] shall prescribe regulations which shall establish a procedure . . . under which each state shall submit to the Administrator a plan which establishes standards of performance *for any existing source . . . to which a section 111(b) standard of performance would apply if such existing source were a new source.*

The statutory scheme is quite straightforward. Under Section 111(b), EPA is required to establish “standards of performance” for any new source within a listed category; and then, under Section 111(d), each state is required to submit a plan that establishes “standards of performance” for “any existing source” in the same category. In either case, it is quite clear from the statute that this standard applies to an individual source – to any new source in the country or to “any existing source” in the state.

This is also clear from another part of Section 111(d), which says that EPA’s 111(d) regulations

shall permit the State in applying a standard of performance *to any particular source* under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of *the existing source* to which such standard applies.

Thus, the statute certainly contemplates that a standard of performance is something that each and every regulated source must meet. EPA agrees with this reading when it comes to new

sources. Over the years, the Agency has established dozens of different “standards of performance” for new sources, and all of them apply to any new source within the regulated category or subcategory. This is even true for carbon emissions. EPA recently proposed “standards of performance” to regulate carbon emissions from new fossil fuel power plants based on its view of the best system of emission reduction that can be applied to each type of plant. If these standards are finalized and upheld in court, each new plant must meet the applicable standard of performance.

But for existing sources, EPA now claims that a “standard of performance” can actually be much broader. Rather than requiring states to submit plans that establish standards for individual power plants, EPA is proposing to require states to submit plans to regulate the whole “electricity system” in the state – and anything connected to that system by either producing or using electricity. Rather than set an emission rate for each existing plant, each state must meet a statewide CO2 emission rate based on a rather complex formula that includes most, but not all, the power generating sources in the state and an estimate of the CO2 emissions avoided by energy efficiency programs designed to reduce electricity demand in the state. This legally binding CO2 emission rate varies substantially from state to state depending on EPA’s view of how each state should change its current electricity system.

This whole program is based on a 37-year old provision in the CAA which says that, under certain circumstances, EPA may require states to submit “a plan which establishes standards of performance for any existing source . . . to which a section 111(b) standard of performance would apply if such existing source were a new source.” To support its expansive new reading of this provision, EPA points to one part of the statutory definition of the term “standard of performance,” which says:

The term “standard of performance” means 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.

EPA focuses on the word “system” and argues that a “system” can involve many different things that all fit together, like the electricity system in a state. But the statute does not say that EPA can regulate a “system.” It says that EPA and the states are to set standards for emissions of air pollutants based on the “application of the best system of emissions reduction.” The question is not what a “system” may be. Rather, the question is the best system as “applied to what”? EPA says, “as applied to anything that produces or uses electricity in the state.” But the answer, according to the statute and almost 40 years of regulatory history, is “as applied to the individual sources within the source category being regulated.” In the context of Section 111(d), this means to “*any existing source*,” as long as, “in applying a standard of performance *to any particular source*,” the state is able to “take into consideration, among other factors, the remaining useful life of *the existing source* to which such standard applies.

The other part of the CAA definition of the term “standard of performance,” in Section 302(l), also makes this clear:

The term “standard of performance” means a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction.

The only plausible reading of the statute is that a standard of performance must be based on “the best system of emission reduction” that can achieve a “continuous emission reduction” at “a source” being regulated, whether it is a new source or an existing source. However, although the term “standard of performance” is the same for both new and existing sources, EPA now claims that, when it comes to existing power plants (but not new ones), the term empowers it to require all fifty states to change the way that electricity is produced and used within their borders. If so, this would be a breathtaking expansion in EPA’s authority based on a novel reading of a statutory provision that has existed for almost 40 years. This is why a number of Supreme Court observers believe that, in its recent *URG* decision (which was released just weeks after EPA announced its proposal to regulate existing power plants), the Court may have been sending a message to EPA:

When an agency claims to discover in a long-extant statute an unheralded power to regulate ‘a significant portion of the American economy,’ *Brown & Williamson*, 529 U. S., at 159, we typically greet its announcement with a measure of skepticism. We expect Congress to speak clearly if it wishes to assign to an agency decisions of vast ‘economic and political significance.’”

What EPA Can Do To Reduce CO2 Emissions But Has Failed to Do

In its 111(d) proposal, EPA has identified four “building blocks” that it uses to develop a CO2 emission rate that applies to the electricity system (at least most of it) in each state. According to EPA, these building blocks make up the “best system of emission reduction” for the state as a whole. The first one – and the only one that has anything to do with EPA’s statutory authority under Section 111 – is based on improvements in efficiency that existing coal-fired power plants can achieve by making changes to their equipment or operations. Where such improvements are possible, they would reduce the carbon emissions rate of individual power plants, as envisioned under Section 111.

But rather than actually doing the technical work necessary to establish legally defensible efficiency standards for existing power plants, EPA simply asserts, with essentially no technical basis, that existing coal-fired power plants can boost their efficiency by 6 percent on average – meaning that they can produce a given amount of electricity by burning 6 percent less coal. Each state is then required to reduce carbon emissions by the amount that would be achieved if every coal-fired plant in the state improved its energy efficiency by 6 percent. It doesn’t matter if power plants in one state already are more efficient than those in another. All states are required to reduce CO2 emissions based on the assumption that their existing plant can produce the same amount of electricity with 6 percent less fuel.

Before EPA can set legally defensible efficiency standards for existing plants, it needs to conduct a more rigorous process backed by research and data. First, the Agency must determine the heat rate (a measure of efficiency) that can be achieved by different types of existing plants. Then it

can establish a carbon emissions rate – as it has already proposed for new plants – rather than an arbitrary percent reduction. When doing so, EPA officials will also need to recognize that existing plants differ significantly from one another, so they will almost certainly need to establish subcategories for different plants based on size, boiler type, age, and other factors. Only then can they establish a carbon emissions rate for each subcategory based on what can be achieved by sources in that subcategory.

Based on discussions with industry experts – people whose job is to make power plants as efficient as possible – it appears that an efficiency improvement of 6 percent is unrealistic for most plants. The Agency must base any requirements on credible research and actual data. To date, EPA has been so distracted by the notion that it can fundamentally change the electricity system in all 50 states that it has not done the technical work needed to develop legally sound regulations to reduce carbon emissions from existing fossil fuel power plants.

A Wasted Opportunity

Over the next year, many different groups – environmental advocacy organizations, companies and trade associations, and state and local governments – will be forced to spend an enormous amount of time and effort trying to understand and comment on a very complicated proposal that is almost certainly unlawful. Even if companies and state and local officials and utility commissioners believe, as I do, that the proposal will never be implemented, they cannot simply ignore it. They must perform studies and hold meetings and try to figure out what they would be required to do on the chance that it will actually come into place. Then, assuming the EPA ignores the legal and practical concerns that have been raised and issues a final rule that follows the same general approach, all these parties will be spending much more time and effort trying to come up with state plans to meet requirements that will almost certainly be set aside.

EPA's very capable staff will also be focused on remaking the electricity system in all 50 states – something it is not authorized or well equipped to do. Rather than devoting so much time and effort on things that are outside its purview, EPA should do what it is supposed to do under the CAA. It should do the technical work that will be needed to reduce carbon emissions from existing power plants by establishing legally defensible standards of performance that will reduce the carbon emission rate from individual power plants.

* * * * *

Again, I very much appreciate the opportunity to appear before the Committee and hope that my testimony will be helpful to you as you review the many issues raised by EPA's proposal to regulate the production and consumption of electricity in the U.S.

Jeffrey R. Holmstead

Jeff Holmstead, former Assistant Administrator of the United States Environmental Protection Agency (EPA) for Air and Radiation, is one of the nation's leading air-quality lawyers and heads the Environmental Strategies Group (ESG) at Bracewell & Giuliani. The ESG is a multi-disciplinary group that includes environmental and energy attorneys, public policy advocates, and strategic communications experts – most of whom have had high-level government experience. Under Mr. Holmstead's leadership, they work together on daily basis to advise and defend companies and business groups confronting major environmental and energy-development challenges, both domestically and globally.

From his time in both the government and the private sector, Mr. Holmstead is very familiar with the environmental and energy challenges facing the business community. He advises clients dealing with an increasingly complex regulatory, legal and public relations landscape, drawing on his experience in policy development, administrative and legislative advocacy, litigation and strategic communications. He has worked with clients in a number of industries on issues related to climate change, Clean Air Act policy and enforcement, and energy policy — including the development of new coal-fired power plants, refineries, renewable energy sources, and electric transmission infrastructure.

Mr. Holmstead headed the EPA's Office of Air and Radiation from 2001 – 2005, longer than anyone in EPA history. During his tenure, he was the architect of several of the agency's most important initiatives, including the Clean Air Interstate Rule, the Clean Air Diesel Rule, the Mercury Rule for power plants and the reform of the New Source Review program. He also oversaw the development of the Bush Administration's Clear Skies Legislation and key parts of its Global Climate Change Initiative. Prior to his appointment at EPA, Mr. Holmstead was a partner in the Environmental Group of Latham & Watkins, which he joined in 1993. Between 1989 and 1993, Mr. Holmstead served on the White House Staff as Associate Counsel to former President George H.W. Bush. In that capacity, he was involved in the passage of the Clean Air Act Amendments of 1990 and the key steps taken to implement those amendments. From 1987 to 1988, he served as a law clerk to Judge Douglas H. Ginsburg on the U.S. Court of Appeals for the District of Columbia.

Education

J.D., Yale Law School, 1987

B.A., *summa cum laude*, Brigham Young University, 1984

Bar Admissions

District of Columbia

Noteworthy

Chambers USA: America's Leading Lawyers for Business, Climate Change, 2010-2013;

Environment, 2008-2013

US Legal 500, *Environment: Litigation*, 2012

Best Lawyers in America, *Environmental Law*, 2008-2010 and 2013

Chairman LUMMIS. I thank the gentleman.
I now recognize our second witness, Mr. McConnell, for five minutes.

**TESTIMONY OF THE HONORABLE CHARLES MCCONNELL,
EXECUTIVE DIRECTOR, ENERGY & ENVIRONMENT INITIATIVE,
RICE UNIVERSITY**

Mr. MCCONNELL. Thank you. I am here to talk about EPA's carbon plan and Clean Power Plan, and unfortunately it is neither of the two.

So what is it and what is it not? Well, it is certainly not impactful environmental regulation. In fact, Administrator McCarthy testified in 2013 to that very effect in front of the House of Representatives and suggested that it was really being developed for political leverage in a global climate discussion.

So let's talk about how much of an impact it really is. It impacts, if fully developed, .18 percent of the global CO₂ that is admitted in the world, less than 2/10 of a percent. It will impact global warming and climate change by .01 degrees centigrade. And that, if you do the mathematics and climate change, technology, would affect the level of sea rise by about 1/3 the thickness of this dime that I am holding. It is hard to see, I know, but it is 1/3 of that thickness.

It is also not flexible. Administrator McCarthy has mentioned that it is too flexible in fact in some States and that we haven't really prescribed it enough. Well, truly, if you look at the outputs of a coal-fired power plant or even a natural gas-fired power plant, you will see that it is a disingenuous comment. In fact, there is no other way for this to be achieved than to simply mandate more windmills and more solar panels. It is just that simple.

And at the end of it all, where is the question on affordability and what have we heard from the EPA? And what you hear right now is the sound of silence. There is nothing that has been said. As a matter of fact, the questions have been dodged, unanswered, and not addressed at all. But if you look at the mathematics of the way it works and the way technology is deployed, on average across this country the average ratepayer will see its rates go up by about two times. But in the five States that are going to bear 40 percent of the burden of this CO₂ reduction, those ratepayers are going to see anywhere from 3X to 4X. So if this gets put forth, you won't have to wonder why your power bill is more expensive; it is directly related to this.

And the other problem is the inconvenient truths are that we don't have any studies on reliability; we don't have any studies on affordability. There is really no evidence of any interagency collaboration, FERC and the natural gas availability for all the fuel switching that is being anticipated. Transmission capacity and capability, the Department of Energy and the Office of Electricity have that capability but there is no evidence that there is any connection there. Operating plant efficiencies by the National Energy Technology Laboratory and Fossil Energy have copious amounts of information that have not been tapped into. And of course the carbon capture and storage and CCS technology development roadmap has fundamentally been avoided with this.

So really this is dangerous and damaging to the American consumer, to industry, and to our global competitiveness. And unfortunately, what we are doing is we are wrapping this up as an environmental victory and there isn't any environmental victory. It is a disingenuous "all pain for no gain" program and it is difficult to understand. I would suggest that what we need to do is pivot this conversation to a discussion around world-class technology so that we can have real environmental responsibility and a real all-of-the-above approach, not just CO₂ but all the issues associated with environmental responsibility not only in our country but globally. We need to study the situation around energy reliability. It is too important and it needs to tap into the agencies that we had here in our system to be able to do that.

And finally, we have to drive toward affordability for all citizens, not just in our country but to think about the global implications of the developing nations around the world and their need for advanced technology. The rest of the world doesn't need our political platitudes and morals. What they need is our technology that we are so capable to develop that we need to fund and deploy.

Thank you.

[The prepared statement of Mr. McConnell follows:]

EPA'S CARBON PLAN: FAILURE BY DESIGN

Testimony before the Committee on Science, Space, and Technology

United States House of Representatives

July 30, 2014

The Honorable Charles D. McConnell

Executive Director, Energy and Environment Initiative, Rice University

Former Assistant Secretary for Fossil, U.S. Department of Energy

Introduction

We all want clean air to breathe and clean water to drink, and there is a growing consensus on the need to reduce our greenhouse gas (GHG) emissions, especially CO₂ emissions. However, how we approach achieving GHG reductions is critical to being able to do so and protect our economy, our global competitiveness and the very quality of our lives. The EPA's proposed rulemaking does not meet the test of relevant and impactful policy to reduce such emissions.

Whenever emission reductions are judged to be needed, some immediately turn to more regulation as a solution without honestly and objectively considering whether the necessary technology is available to achieve that regulation. If the technology is not available, passing a regulation that requires its deployment makes no sense. It can take well over twenty years to develop a technology from its laboratory cradle through commercial demonstration and many more years to achieve broad commercial deployment. Technology enables innovation and regulation and not vice versa. Once a given technology is commercially viable and available, correctly written regulation can incentivize further, incremental improvement of that technology.

So where are we today with commercially viable CO₂ capture and storage or utilization (CCS/CCUS) technology? Commercial CCS technology is still in the laboratory cradle. Today's CCS technology deployed on a coal power plant will increase the cost of the generated electricity by 80 percent (the size of the cost penalty varying with the percentage capture), with unknown overall plant reliability and availability and unknown long-term CO₂ storage liability. Worse yet, DOE has been dramatically cutting the budget for developing CCS technology, thus assuring that its commercial availability will be delayed by decades. Even the Senate Appropriations Committee in its Energy and Water Subcommittee markup for the fiscal year 2015

appropriations bill last week, cut funding for CCS and power systems by over 30 percent (from the current \$392M level to \$267M).

What does all of this mean? These facts are well known to EPA officials, leading an objective observer to conclude that the EPA motivation for issuing its GHG regulations was not to reduce GHG emissions, but rather to eliminate fossil fuels – first by eliminating coal use and later natural gas and other fuels – irrespective of its economic impacts on consumers (especially low income consumers). EPA will manipulate numbers and disagree that their regulations are causing severe economic impacts, but the fact is that electricity prices are rising in states that are retiring coal plants. DOE will cite the billions of dollars spent on current CCS demonstration projects (over 80 percent of those funds are from the private sector). These demonstrations are needed to demonstrate the operability of current CCS/CCUS technology. However, they are not currently operating and they will not be demonstrating the low cost CCS technology that has yet to be developed and that is necessary to meet EPA GHG regulations. EPA has essentially recognized this point by not requiring CCS on existing coal plants and imposing requirements that will result in the replacement of existing coal plants thus making their motives and strategy transparent to all.

Existing Fleet and Efficiency

EPA has proposed four “building blocks” to get to the goal of reducing carbon emissions from coal-fired power plants by 30 percent from 2005 levels by 2030. Those are: improve efficiency at each power plant by 6 percent as a fleet-wide average; employ “environmental dispatch” to run natural gas plants more and coal plants less; substitute renewable energy for coal; and reduce demand from consumers by 1.5 percent per year.

So let's talk about power plant efficiency. What does a 6 percent efficiency improvement look like? To be honest, I can't tell you, and I'm not sure anyone can really tell you, because I'm not sure it's ever been done before. The existing coal fleet average efficiency is somewhere in the 33 to 35 percent range, meaning a power plant is 33 to 35 percent efficient in converting the energy value of the raw material into actual usable energy output, or Btus. If you converted a power plant from 35 percent efficiency to 41 percent efficiency, you essentially would be looking at rebuilding the entire plant. AEP's Turk plant in Arkansas will have a 39-40 percent steam cycle efficiency, as opposed to about a 35 percent average coal-fired plant steam cycle efficiency. To get those extra 4-5 percent efficiency points, they built a plant that is entirely different from a subcritical coal plant.

The National Coal Council's (NCC) most recent report, issued just two months ago, specifically looked at possible power plant efficiency improvements. The NCC stated that its report "does not provide a quantitative assessment of the degree to which these existing technologies could improve the heat rate (or efficiency) of the existing coal fleet," but there are other credible sources to show what is feasible for existing coal plants.¹ For example, an International Energy Agency paper from the fall of 2013 noted that "Retrofits will increase efficiency significantly, by up to as much as 2-3 percentage points, and may compensate completely for loss of performance from addition of environmental control equipment after a plant was first commissioned."² Two to three percent. That's half to one-third of EPA's six percent.

¹ See the Reliable & Resilient: The Value of Our Existing Coal Fleet the National Coal Council's May 2013 report at <http://www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf>

² International Energy Agency, Upgrading and efficiency improvement in coal-fired power plants, No. 13/9, August 2013, <http://www.iea-coal.org.uk/documents/83185/8784/Upgrading-and-efficiency-improvement-in-coal-fired-power-plants,-CCC/221>.

The NCC's report does list a number of changes that could be made at a power plant to improve efficiency. It is useful to simply insert here the findings of that expert group on power plant efficiency improvements, as summarized in the report's executive summary:

“Coal could potentially be dried using waste heat, making the boiler more efficient. Steam turbines could potentially be refit with modern and more efficient multistage rotors. In addition, corrosion and deposition on major heat transfer components (boiler tubes and condensers) could potentially be reduced, making heat transfer in those components more efficient.

“On some units, alkali materials can be injected into flue gases to reduce acidity that would otherwise present corrosion problems at low temperatures, thereby potentially allowing greater heat recovery from flue gases. Improved sensors and controls could potentially allow a plant to operate closer to conditions optimal for higher efficiency. Variable speed drives could potentially be used to make motors more efficient, particularly at lower load.

“While many of the needed technologies already exist and are operating on some units, these are not a one-size-fits-all package of solutions that can be readily applied to or accommodated by the existing coal fleet. The opportunity to apply these efficiency improvements across the existing fleet will vary significantly.

“In some cases, the opportunity will be negligible because the unit either is already operating in a highly efficient mode with some or all of the improvements in place or because the implementation of potential improvements is not cost-effective and/or technically feasible. As such, the degree of efficiency improvement possible at a given unit is highly site-specific, and may depend on the design of the unit, current maintenance

procedures, whether the unit operates as base load or cycling, the type of coal used by the unit, system economics and the economics of the specific measure and the configuration of the unit. Even the location of a unit is relevant to efficiency because plant efficiency is sensitive to ambient temperature and atmospheric pressure (elevation).³

Congress recognized in the Energy Policy Act of 2005 that getting even 4 percent efficiency improvement was so costly that it established a massive tax credit as an incentive. Section 1307 of the EPACT provides \$1.3 billion in tax credits to “advanced coal-based generation technology” projects, which for existing units are defined to include projects on units that “achieve[] a minimum efficiency of 35 percent and an overall thermal design efficiency improvement, compared to the efficiency of the unit as operated, of not less than –

- 7 percentage points for coal of more than 9,000 Btu
- 6 percentage points for coal of 7,000 to 9,000 Btu, or
- 4 percentage points for coal of less than 7,000 Btu⁴

By the way, that’s a “design” efficiency improvement, which recognizes that the plant ultimately may get less thermal efficiency improvement in operation.

The bottom line is that Congress knew this was “rebuild the power plant” levels of efficiency improvements, hence the tax credit. EPA, of course, argues that the proposed rule provides “flexibility,” and that not everyone will have to do this everywhere. Yet its final GHG reduction level is based on 6 percent efficiency improvement being the industry-wide average (i.e., because it has baked 6 percent industry-wide efficiency improvement into the 30 percent below 2005 level target).

³ See the pg. 4-5 of Reliable & Resilient: The Value of Our Existing Coal Fleet the National Coal Council’s May 2013 report at <http://www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf>

⁴ See P.L. 109-58 Section 1307 at <http://www.gpo.gov/fdsys/pkg/PLAW-109publ58/html/PLAW-109publ58.htm>

Finally, it is important to note that there are legal barriers to doing power plant efficiency improvements, and EPA knows it well. Specifically, significant changes to an existing power plant trigger a provision of the Clean Air Act known as “New Source Review” or NSR. Essentially, under this statutory provision, existing industrial facilities are treated like new facilities for the purposes of clean air permitting when “major modifications” are made, meaning they become subject to more stringent air limits that can be very expensive to meet. EPA had discretion in determining what is a major modification, and power plants and other industrial facilities sensibly do all they can to avoid triggering the requirements and their subsequent expenses. In the case of CO₂ emissions, EPA surely must know it is creating a catch-22: big efficiency improvements will trigger NSR, which will require the installation of equipment to reduce other emissions and decrease efficiency. Again, the NCC’s report summarizes the issue well: “In general, if a plant owner expects that an efficiency improvement would lead to [NSR] designation, the efficiency project will not be pursued as the resulting permitting process would be extensive and the compliance requirements would be onerous and likely too stringent to be practicable. Unfortunately, this prospect has all but eliminated RD&D that would more than marginally innovate the fleet.”⁵

Current Situation (Failure by Design)

On June 25, 2013, President Obama issued his Presidential Memorandum – Power Sector Carbon Pollution Standards. In this memorandum to EPA, he directed the agency, by September 30, 2013, to issue a new proposed rule to establish New Source Performance Standards (NSPS) for CO₂ emissions from fossil fueled power plants, replacing the rule EPA proposed for that

⁵ See the pg. 5 of Reliable & Resilient: The Value of Our Existing Coal Fleet the National Coal Council’s May 2013 report at <http://www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf>

sector on April 13, 2012. He also directed EPA to propose standards or guidelines governing emissions from existing power plants by June 1, 2014.

The most constructive thing that can be said about the resulting proposed regulations is that EPA almost met the President's schedule. They published the first rule on their website on September 20, although it did not appear in its final form in the Federal Register until January 8, 2014. The existing source rule was released on EPA's website on June 2, and the formal version was printed in the Federal Register on June 18. That's the good news.

The bad news is that these proposals follow such a tortured logic that there is a reasonable likelihood that a reviewing court will, perhaps three or four years from now, determine that EPA's legal and technical arguments lack merit and the agency must start over again.

My background is in technology and I would like to offer you my views on why I believe that EPA's two proposed power plant rules are harmful to technology development, and, because of that, will probably have the perverse effect of increasing CO₂ emissions, regardless of whether they withstand litigation or are reversed.

First, let us review the fundamental legal criterion for both the Section 111(b) NSPS rule and the Section 111(d) existing source performance standards rule: the Clean Air Act's definition of a "standard of performance." "The term 'standard of performance' means 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." The key phrase here is "best system of emission reduction which ... has been

adequately demonstrated.” These are the brutal facts regarding the technology we are all focused upon, CCS:

- The technology is not “adequately demonstrated.” In fact, it has not been demonstrated at all in the sense Congress intended in the Clean Air Act. There is no commercial scale CCS system operating on a power plant (coal, gas, or oil-fired) anywhere on the planet. That is a fact.
- At least two major power plant vendors have provided official statements that CCS technology is not ready for commercial deployment. The first, Bob Hilton, VP at Alstom Power, offered his view before this Committee at a hearing on March 12, 2014. “Alstom does not currently deem its technologies for Carbon Capture commercial and, to my knowledge, there are no other technology suppliers globally that can meet this criteria or are willing to make a normal commercial contract for CCS at commercial scale.”⁶ The second view was offered by B&W in that company’s formal comments on EPA’s proposed NSPS rule. “As a developer and supplier of CO2 capture technologies, we do not agree that these technologies are ready for commercial deployment on new EGUs today to meet this emission limit.”⁷ These statements from two companies at the forefront of CCS and power technology are tantamount to facts.
- Multiple reports and technical studies by the Department of Energy have concluded that adding CCS to a traditional coal-fired power plant will increase the cost of electricity from that unit by about 80 percent. This is an unacceptable cost increase and is one of the primary reasons that DOE spends about \$400 million a year to improve CCS technology. These are facts.

¹ Testimony by Robert Hilton before the US House of Representatives Subcommittee on Environment and Subcommittee on Energy, of the Committee on Science, Space, and Technology, March 12, 2014.

⁷ B&W, Comment available on the EPA regulatory docket, document # EPA-HQ-OAR-2013-0495-8348.

- Although we are conducting research in carbon storage, we have relatively little experience with injection of large quantities of CO₂ into geologic formations – none at the 3-4 million TPY rate typical for a large coal-fueled power plant. EPA regulations intended to protect groundwater supplies require CO₂ storage facilities to monitor the underground CO₂ plume for 50 years after CO₂ injection has ceased to ensure that nothing goes wrong. These are facts.
- The other option for storage of CO₂ is Enhanced Oil Recovery (EOR), which provides the economic bonus of enabling production of high value crude oil. However, EPA’s proposed NSPS included provisions making EOR activities impractical, at least in the view of one major EOR producer. A white paper⁸ on the reporting requirements of the rule by Denbury stated, “the proposed NSPS rule will *foreclose – not encourage* – the use of CO₂ captured by emission sources in EOR operations.” [emphasis in original] EPA’s requirements convert a resource recovery operation into a waste disposal operation, which is incompatible with EOR activities. EOR is a dynamic process that involves “a host of changes to the originally-approved plan.” EPA’s proposed monitoring, reporting, and verification requirements would necessitate re-permitting the operation after every change and expose the project to time consuming permit challenges and litigation. More unpleasant facts.

Against these facts, let us review EPA’s views on CCS technology:

⁸ Subpart RR Flaws Preclude EPA’s Reliance on CO₂-EOR in the Proposed NSPS Rule, Denbury, (undated).

- “[W]e are not proposing that CCS does or does not qualify as the “best system of emission reduction” that “has been adequately demonstrated” for new coal-fired power plants.”⁹
- “EPA believes that partial CCS should be considered BSER.”¹⁰
- “The EPA believes the cost of ‘full capture’ CCS without EOR is outside the range of costs that companies are considering for comparable generation and therefore should not be considered BSER”¹¹
- “[T]he EPA is not proposing and does not expect to finalize CCS as a component of the BSER for existing EGUs in this rulemaking.”¹²

These are EPA’s views from regulatory proposals for new and existing power plants made public in 2012, 2013 and 2014, seemingly (and in some cases actually) conflicting with one another, without any significant change in during that period in the readiness of the technology.

I believe in technology solutions to technical problems like pollution. There is a strong track record of government and the private sector collaborating to develop technologies like flue gas desulfurization, selective catalytic reduction, and mercury capture systems – when provided adequate federal resources and time. Past NSPS rules for SO₂ and NO_x emissions did this: they based a regulation on proven, monitored application of a technology on many commercial scale units. I believe that with adequate time and resources, CCS can make a major contribution to the effort to address global climate change. However, the Administration in its proposed CO₂ NSPS

⁹ USEPA, preamble to 2012 proposed power plant NSPS. 77FR22411, April 13, 2012.

¹⁰ USEPA, preamble to 2014 proposed power plant NSPS. 78FR1479.

¹¹ *Ibid.*, p.1435.

¹² USEPA, preamble to 2014 proposed rule for existing power plants, 79FR34857, June 18, 2014.

can point to no commercial operating units with CCS, and the Administration is proposing again to reduce funding for coal and CCS research.

This is not just about coal, or CCS, or electric utilities. The existing coal fleet provides about 40 percent of our electricity and does so at about half the cost of any technology that would replace those existing units. The U.S. enjoys electricity priced at about one-half to one-third that of most of Europe. This means more money in the pockets of American consumers, and a competitive edge for U.S. manufacturing in international markets. It would be more than a shame to throw away those enormous economic benefits by reaching beyond our grasp on these two proposed regulations. But we are headed in that direction. (See Appendix B for a compelling presentation of the effect EPA's rulemaking will have on my home state of Texas.) We are already on a path to retire about 20 percent of our existing coal units by 2018, even though many of those units were essential to getting us through last winter's cold waves. And these proposed rules promise to stop any new coal units, while forcing another 20 percent to retire, at least according to EPA. A close study of EPA's technical support documents certainly supports concerns that the system impacts could be much worse.

It is bad enough that EPA's rules will put our nation's electric reliability at risk and significantly increase electricity rates. As somebody who has spent his professional life trying to advance technology, a pill that is almost as bitter to swallow is the fact that EPA has failed to propose a *technology* rule when the problem the President has announced he wants to address will **demand** a *technology* solution.

The President and Administrator McCarthy have said that the problem of global climate change will demand "leadership" from the United States. For years, we were heading down that path by fully funding DOE's public-private partnerships to incubate CCUS so that, one day, the

world's coal fleet would have a technology solution capable of making meaningful progress toward that goal. Yet, now, by simultaneously underfunding CCUS research and implementing regulatory mandates that will hinder, not further, CCUS development, we are not just failing to "lead," we are undermining the world's ability to develop the one technology that has a prayer of addressing the problem.

Technology has benefits to the environment and the economy that don't need to be cut off by EPA rulemaking. We know that the opportunity is out there for CCS, or more accurately CCUS. In the U.S., we have two major projects being undertaken by the private sector to capture carbon from a power plant and use the CO₂ for enhanced oil recovery. One is Southern Company's Kemper County facility in Mississippi, a new facility nearing completion at which the company will gasify lignite, produce a syngas that will be combusted to generate electricity, produce several byproducts like fertilizer and industrial chemicals, and produce a clean CO₂ stream, which will be sold to oilfield companies for enhanced oil recovery. The other is NRG's project at the existing W.R. Parish plant, a post-combustion capture project where the CO₂ again will be used for enhanced oil recovery. This is the kind of technological leadership that needs to be encouraged, not precluded as a consequence – intended or unintended – of environmental policy.

Conclusions

There are four fundamental flaws in the EPA's approach to the three rules proposed and they are the following:

1. Meaningful policy must be both relevant and impactful. DOE has the ability to provide such analysis. Why is it not referenced and included? Interagency collaboration is

anticipated and required. Where is it? From a purely scientific standpoint, the implications of these rules are that:

- They address 0.18% of global CO₂ emissions
 - Climate science would equate that to 0.01 degree Celsius of global warming impact
 - Resulting impact to sea level is the thickness on four sheets of paper or 1/3 the thickness of a dime
 - This rulemaking does not meet the test of meaningful GHG policy
2. Technology capabilities and assumptions made by EPA in unit and system performance are not founded on science and engineering. Notwithstanding the fact that U.S. coal-fired power plants and natural gas-fired facilities are the most efficient in the world, the targets set are clearly beyond achievable targets – especially in a global setting.
3. EPA appears to have approached the challenge with a politically driven end game in mind and worked in reverse to make necessary assumptions to meet targets, including:
- Availability of the necessary infrastructure to enable switching to natural gas from coal.
 - Availability of the system and transmission infrastructure to enable renewable and gas replacement of coal.
 - Assuming natural gas plant utilization factors unrealistically high.

- Assuming technology insertion when technologies are unproven and not commercially available. I testified nearly a year ago on the absurdity of that assumption that was based on plants not yet build or operational.
4. Environmental policy cannot be developed in a vacuum with energy affordability and security not considered. System reliability will be impacted negatively and analyzing “reserve adequacy” is an incomplete approach that is dangerous to our energy security. Affordability is never mentioned in any manner and estimates range from a low side of two-times to a high side of four-times the average cost to the customer in states most impacted. More troubling in both of the areas is that there is no body of work addressing these issues. Why?

It is all pain for no gain. We need technology to address existing coal and natural gas facilities as the world will double over the next 50 years and in 2060 global energy will still be >80% supplied by coal and natural gas. Forcing this rule on the U.S. will:

- Hobble U.S. competitiveness in the global marketplace.
- Not impact the climate in any meaningful way through rulings on CO₂.
- Not provide technology leadership the rest of the world can follow
- Assure the failure of CCS/CCUS by cutting funding for the development of low cost CCS/CCUS technology

Most importantly, we may be declaring victory against GHG emissions and climate change by majoring on the minor. We are not looking at comprehensive solutions, we cannot achieve environmental or economic success through focusing just on CO₂ for coal-fired power plants.

National Coal Council – Reliable & Resilient: The Value of Our Existing Coal Fleet

APPENDIX A

Turbine Upgrade or Efficiency Improvement Projects Cited in NSR Enforcement Initiative

This list is limited to turbine upgrades or replacements – the list would be much longer if improved materials of construction and improved designs of heat transfer surfaces were included.

1. Turbine Upgrade or Efficiency Improvement Projects Cited in NSR Enforcement Initiative

- *United States v. Duke Energy Corp.*, No. 00-cv-01262 (M.D.N.C. Dec. 22, 2000) (GE Dense Pack turbine upgrades at Belews Creek Units 1 and 2 and Marshall Unit 3);
- *New York v. Niagara Mohawk Power*, No. 02-CV-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶ 202 (“upgraded the turbine” on Huntley Unit 63 in 1987), ¶ 323 (“replaced the turbine” on Huntley Unit 67 in 1991);
- *United States v. East Kentucky Coop.*, No. 04-34-KSF, Compl. (E.D. Ky. Jan. 28, 2004), ¶ 60 (“replacement or renovation ... of major components of the ... turbine at the unit” on Dale 4 in 1995-1995), ¶ 76 (“replacements or renovations of major components of the ... turbine” on Dale 3 in 1996);
- *Sierra Club v. Portland General Electric*, No. 08-cv-01136, Am. Compl. (D. Or. Nov. 29, 2010), ¶ 134 (“a plant turbine upgrade” at Boardman in 2003);
- *United States v. Ameren Missouri*, No. 4:11-cv-77, Am. Compl. (E.D. Miss. June 28, 2011), ¶ 67 (“associated turbine replacements” at Rush Island Unit 1 in 2001-2002), ¶ 73 (“associated turbine replacements” at Rush Island Unit 2 in 2003-2004);
- *Conservation Law Foundation, Inc. v. Public Service of New Hampshire*, No. 11-cv-00353, Compl. (D.N.H. July 21, 2011), ¶ 49 (“removed a high pressure/intermediate pressure turbine, and replaced it with a new HP/IP turbine” at Merrimack Unit 2 in 2008);
- *Dine Citizens Against Ruining Our Environment v. Arizona Public Service Company*, No. 1:11-cv-889, Am. Compl. (D.N.M. Jan. 6, 2012), ¶ 48 (“replacement of the high pressure turbines” at Four Corners Units 4 and 5 in 2007), *id.* (“Plaintiffs are informed and believe ... that these high-pressure turbine upgrades increased the design-level heat input rate of each of these units, thereby increasing each unit’s generating capacity and its potential to emit air pollution.”);
- *United States v. Dairyland Power Coop.*, No. 12-cv-462, Compl. (W.D. Wisc. June 28, 2012), ¶ 38 (“upgrading of the turbine at the J.P Madgett Unit in 2004”);
- *Sierra Club v. PPL Montana LLC*, No. 1:13-cv-32, Am. Compl. (D. Mont. Sept. 27, 2013), ¶ 55 (“Replacement of the Low Pressure Turbine” on Unit 3 in 2011), ¶ 57 (“High Pressure/Intermediate Pressure Turbine Replacement” at Unit 2 in 2008), ¶ 58 (“High Pressure Turbine Replacement” at Unit 3 in 2007), ¶ 59 (“High Pressure Turbine Replacement” at Unit 4 in 2006), ¶ 60 (“Replacement of the High Pressure and Intermediate Pressure Turbines” at Unit 1 in 2006).

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2. Standard Turbine Overhauls or other Turbine Projects Cited in NSR Enforcement Initiative

- *United States v. Cinergy*, No. IP99-1693, Third Am. Compl., (S.D. Ind. June 29, 2006) at ¶ 172 (replacement of “turbine blades” on Beckjord Unit 6 in 1994);
- *United States v. Duke Energy Corp.*, No. 00-cv-01262, Compl. (M.D.N.C. Dec. 22, 2000), ¶ 32 (“turbine overhaul” at Allen Unit 5 in 2000), ¶ 60 (“turbine overhaul” at Allen Unit 4 in 1998), ¶ 195 (“turbine rehabilitation” at Cliffside Unit 4 in 1990);
- *Sierra Club v. Dayton Power & Light, Inc.*, No. C2-04-905, Compl. (S.D. Ohio Sept. 21, 2004), ¶ 43 (“overhaul of the turbine” on Stuart Unit 1 in 1980);
- *United States v. American Electric Power*, No. C2-05-360, Compl. (S.D. Ohio Apr. 8, 2005), ¶ 97 (“replacement of the low pressure turbine rotor” on Conesville Unit 5 in 1997), *id.* (“replacement of the low pressure turbine rotor” on Conesville Unit 6 in 1997);
- *Sierra Club v. PPL Montana LLC*, No. 1:13-cv-32, Am. Compl. (D. Mont. Sept. 27, 2013), ¶¶ 53 (“Low Pressure Turbine Overhaul” at Unit 1 in 2012), *id.* (“Turbine/Generator Base Overhaul” at Unit 1 in 2012), ¶ 54 (“Turbine Generator Base Overhaul” on Unit 2 in 2011), ¶ 55 (“Turbine Generator Base Overhaul” on Unit 3 in 2011), ¶ 55 (“Intermediate Pressure Turbine Overhaul” on Unit 3 in 2011), *id.* (“Turbine/Generator Base Overhaul” on Unit 3 in 2011), ¶ 56 (“LP1 & LP2 Turbine Rebuild” at Unit 4 in 2009), *id.* (“Low Pressure Turbine” at Unit 4 in 2009), *id.* (“Turbine/Generator Base Overhaul” at Unit 2 in 2008), *id.* (“Low Pressure Turbine Overhaul” at Unit 2 in 2008), ¶ 59 (“Intermediate Pressure Turbine Overhaul” at Unit 4 in 2006).



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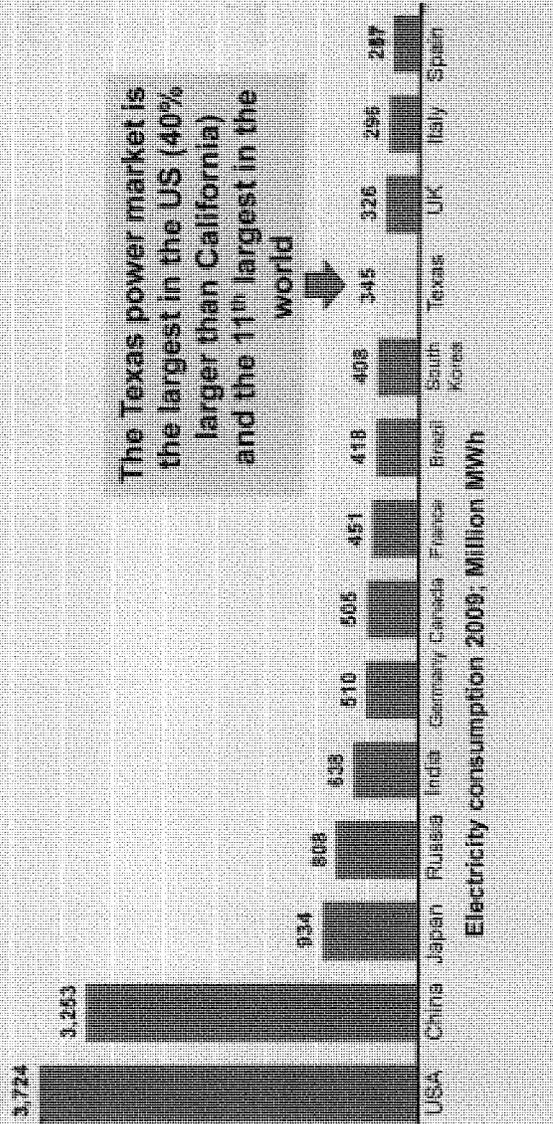
An Assessment of the Impact of EPA's 111(d) Rule (a.k.a. "Clean Power Plan") on Texas

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July 7, 2014

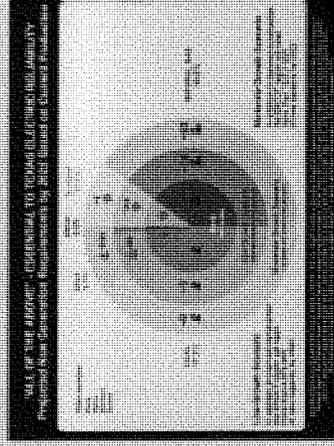


**Population, Industry, & Climate Make
the Texas Power Market...
*“Like a Whole Other Country”***



NO MEGAWATTS TO SPARE: Texas Uses a Diverse Range of Fuels, Including Coal, to Keep Reliability Up & Cost Down

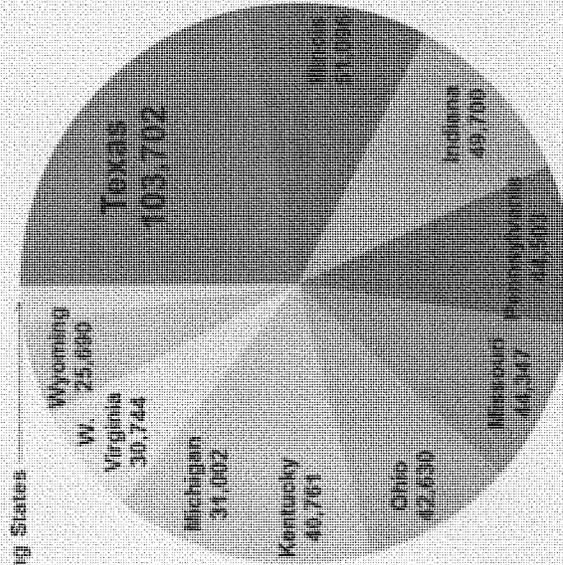
- Texas uses more energy than any other state in the nation, almost as much as the next two states combined (California and Florida).
- *Nearly half of Texas' electricity use is for industry and manufacturing, which includes the oil & gas and petrochemical industries (more than next 3 states combined).*
- To keep costs down and production up, Texas uses coal to maintain fuel diversity – accounts for 37-40% of grid



Source: Energy Consumption by End-Use Sector, Ranked by State, 2010 Rankings, U.S. EIA

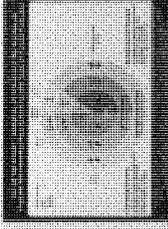
Because of its Size, Texas Consumes Twice as Much Coal as Any other State

U.S. THERMAL COAL CONSUMPTION (tons)

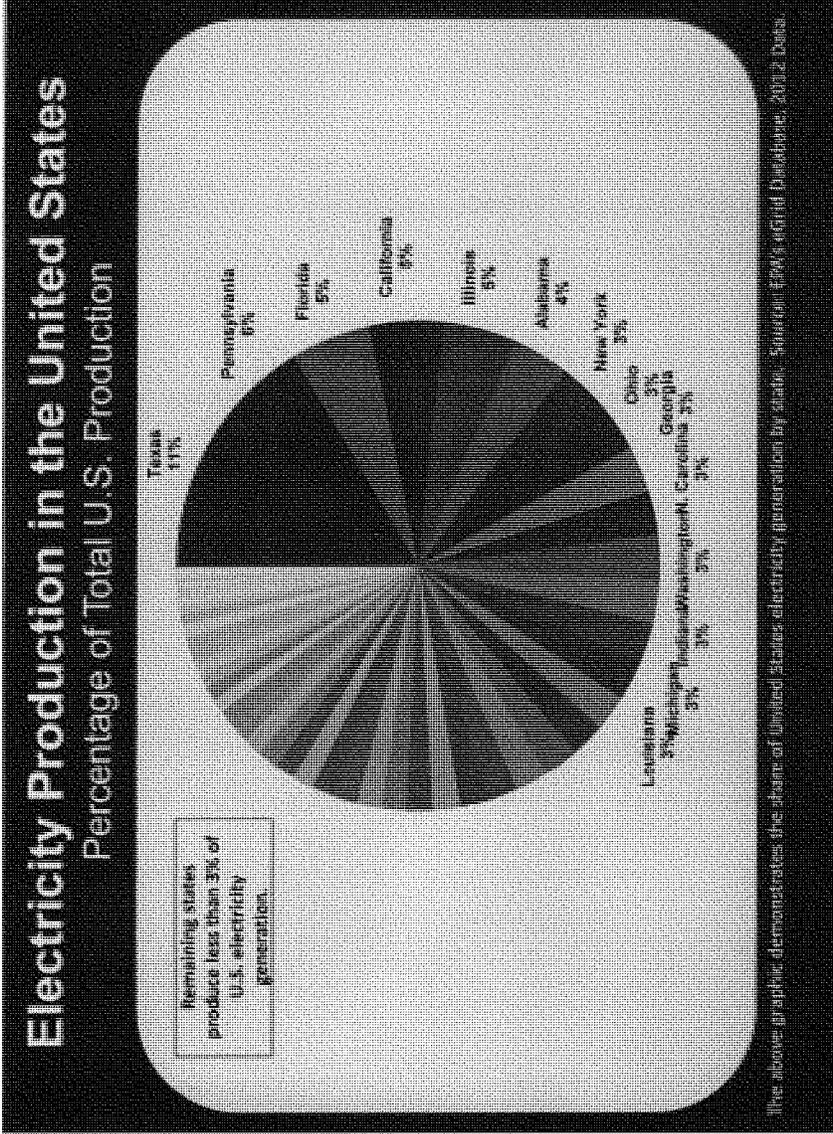


Source: U.S. Energy Information Administration, Annual Coal Report, 2012. In order to reduce the impact of market swings, coal consumption is based on an average of the coal consumption for 2011 and 2012.

Texas Carrying Disproportionate Burden of EPA Carbon Reductions

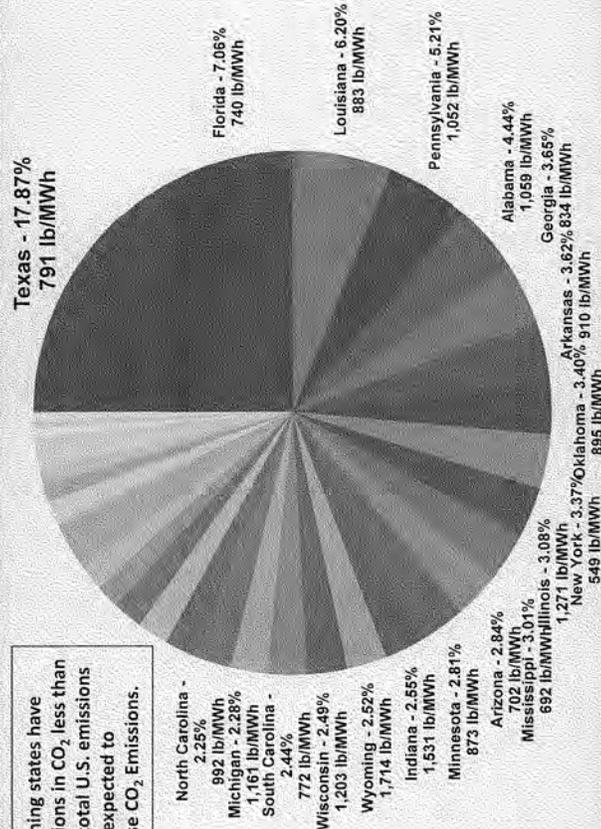


- A legitimate claim could be made that Texas should not have to reduce a proportionate share because it produces a majority of our nation's fuels, chemicals and goods (we do everyone's dirty work)
- Yet, when you compare the next two slides, you can see that EPA is not just making Texas carry its share, but almost TWICE its proportionate share (11% of U.S. generation and 18-25% of CO2 reductions)



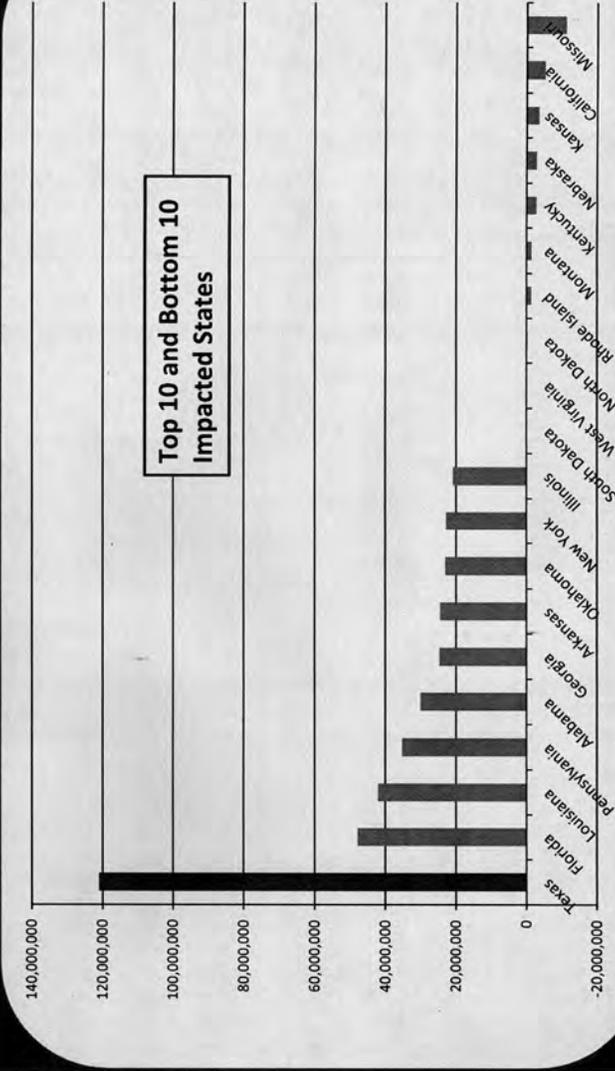
States' Proportion of Total CO₂ Reductions from Electric Generation by 2030 (budgeted rate)

Remaining states have reductions in CO₂ less than 2% of total U.S. emissions or are expected to increase CO₂ Emissions.



Graph does not include Alaska and Hawaii because data was not available. Vermont is excluded because it is not covered by EPA's rule. The following states were excluded from the graph because they are anticipated to have gains in CO₂ emissions: North Dakota (1.0%), Kentucky (3.0%), California (7.0%), Montana (8.0%), Kansas (10.0%), Nebraska (10.0%), Missouri (14.0%), and Rhode Island (37.0%). Sources: EPA's eGrid 2012 Data & Bloomberg, New Energy Finance analysis (for the rate-to-mass conversion on which percentages are based).

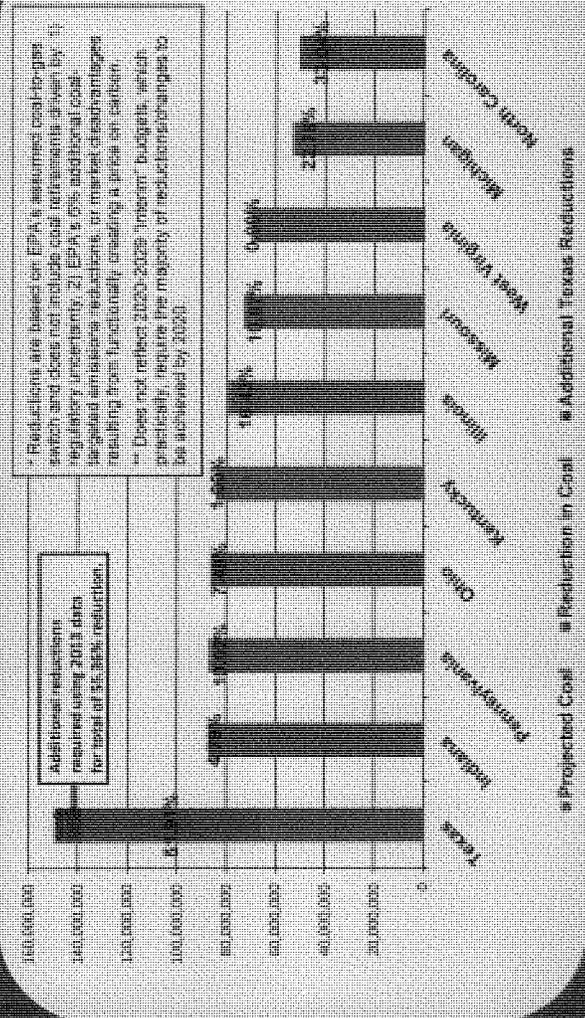
States' CO₂ Reductions from Electric Generation by 2030 (budgeted rate)



Graph does not include Alaska and Hawaii because data was not available. Vermont is excluded because it is not covered by EPA's rule. Sources: EPA's eGrid 2012 Data & Bloomberg, New Energy Finance analysis (for the rate-to-mass conversion on which percentages are based).

EPA's Modeled Reductions in Coal Generation

Comparison of Top 10 Generators of Coal Electricity – Final 2030 Target

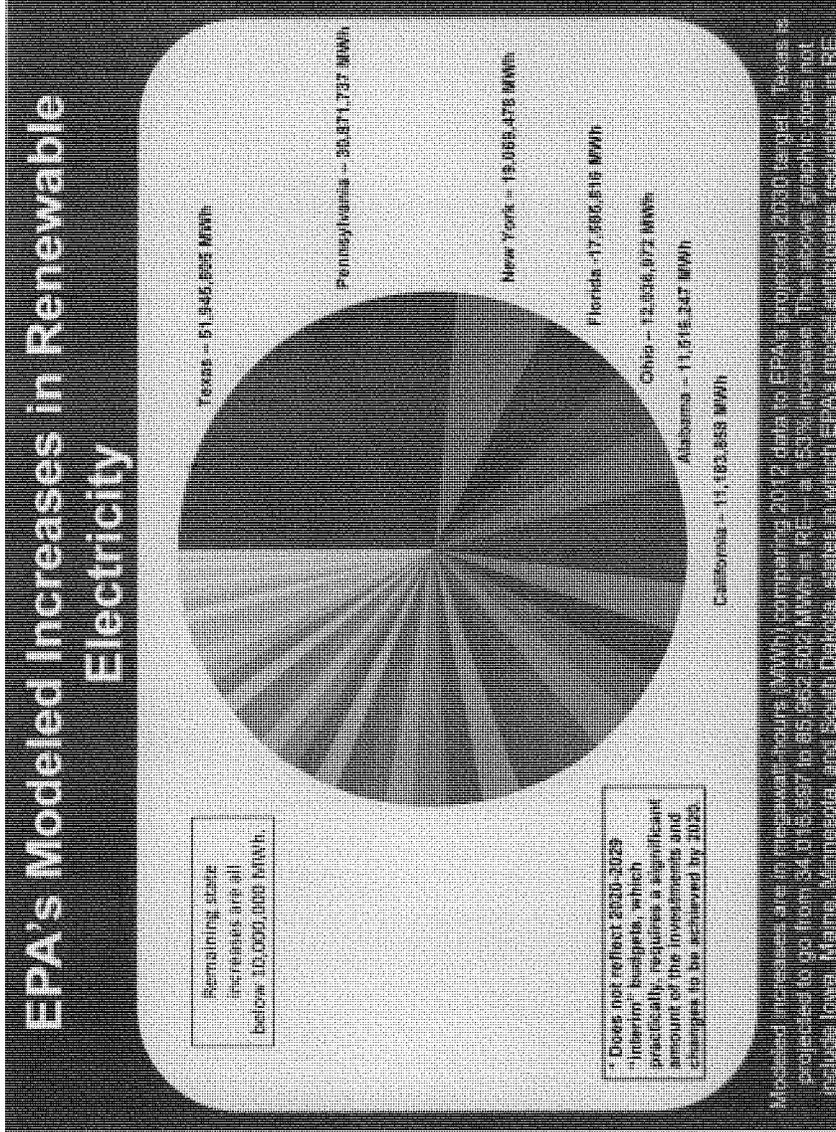


* Reductions are based on EPA's assumed coal-to-gas switch and does not include coal refinements driven by regulatory uncertainty. 2) EPA's 2013 additional coal baseline emissions reductions, or market advantages resulting from functionality creating a price on carbon.

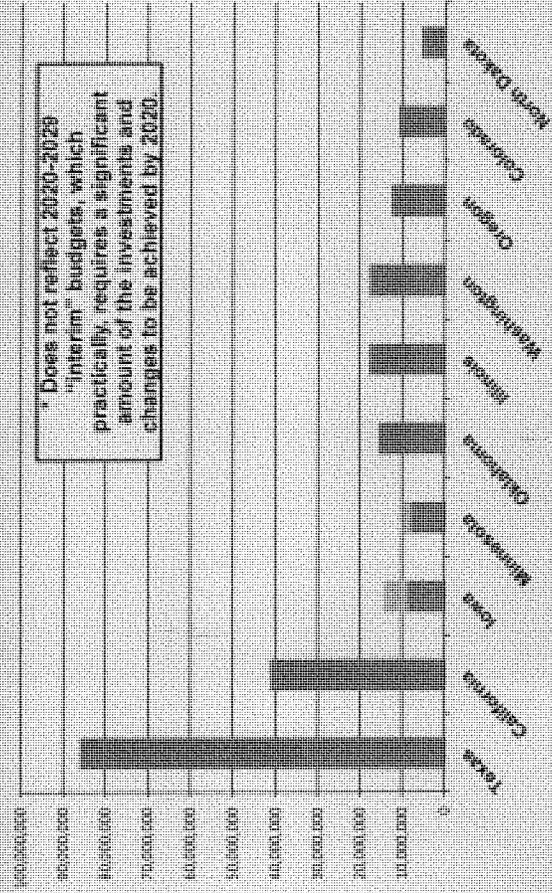
** Does not reflect 2020-2028 "reservoir" budgets, which, practically, require the majority of reductions to be achieved by 2020.

Additional reductions required using 2013 data for total of 52,858 MWh reduction

Modeled reductions are shown in megawatt-hours (MWh) compared to 2012. EPA's projected 2030 target for Texas is projected to reduce coal generation from 134,705,500 MWh in 2012 to 81,846,233 MWh in 2030 – a reduction of 39.31%. In 2013, Texas coal generation actually reached 149,604,241 MWh, which would result in a difference of 67,757,908 MWh from EPA's 2030 target.



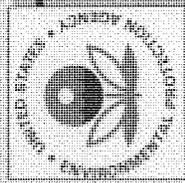
EPA's Modeled Increases in Renewable Electricity (Top Ten Producers)



* Does not reflect 2020-2029 "interim" budgets, which practically requires a significant amount of the investments and changes to be achieved by 2020.

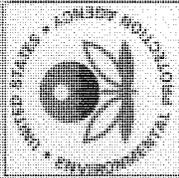
■ 2012 RE ■ Increase in RE ■ Decrease in RE

Modeled increases are in megawatt hours (MWh) comparing 2012 data to EPA's projection 2029. *suppl. Texas is projected to go from 46,014,987 to 95,000,000 MWh in RE. * 2012. Increase. California fully covered by increase in renewable electricity generation by 37%. From 2020 to 2029. EPA's model assumes that Texas will increase renewable electricity generation by 114.6% while California is projected to increase by 95%.

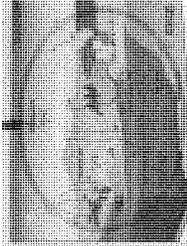


Texas WILL Fight EPA's Illegal Re-Engineering of our Fleet

- EPA claims states have "flexibility" but the reality of mandated state budgets strictly limit options available to states
- Majority of the rule's reductions come "outside the fence" by assuming fuel-switching & build-out of renewables & efficiency
- Disparate impact on Texas will strike at the heart of the U.S. production of fuels, chemicals, and manufactured goods.
- SIP disapprovals & FIPs could result in unprecedented clash between EPA and states ("Come and Take it")
- Immediate task is to build case for irreparable harm & political intervention to keep the rule from coming into effect



EPA'S Carbon Rule is "All Pain – No Gain"



(based on EPA analysis/methodology in light duty vehicle rule and assuming accuracy IPCC projections):

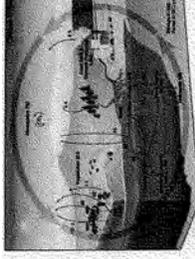
- Addresses only 0.18% of world's CO₂ emissions.
- Global temperature reduced by only 0.01 degrees C
- Mitigation of 0.016 inch of sea level rise; the thickness of 4 sheets of paper or 1/3rd the thickness of a dime

14



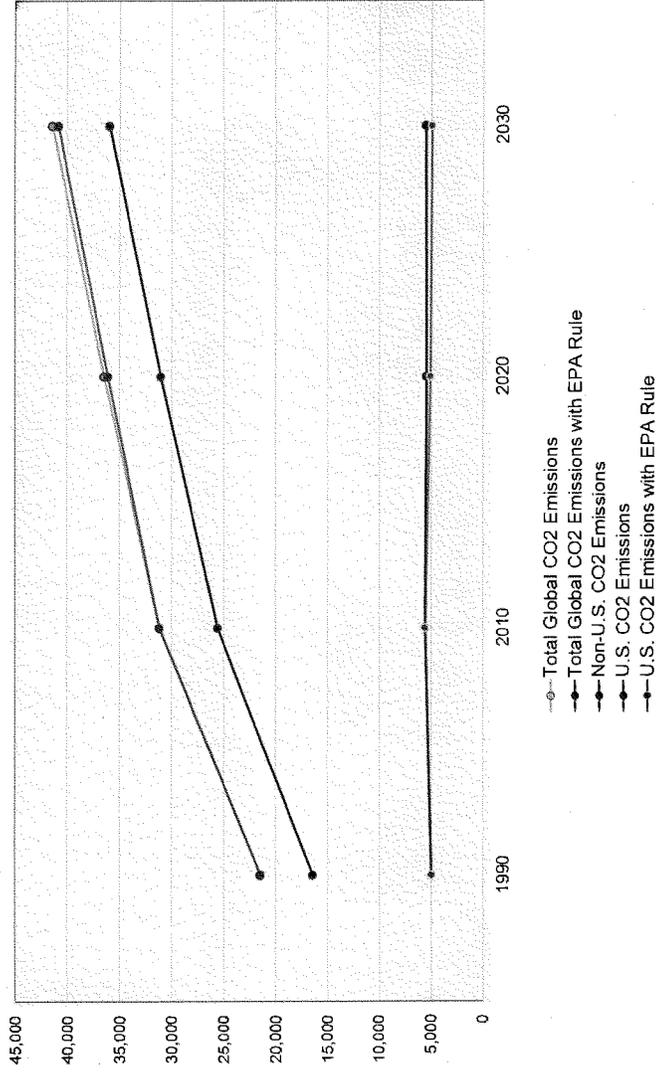
No Gain

(due to World energy realities)



- Non-U.S. CO₂ emissions are projected to increase 55 percent between 2010 and 2040.
- Between 2011 and 2030, annual non-U.S. power sector carbon emissions are projected to increase by 4,692 million tons
- BOTTOM LINE: 111(d) rule reductions will be offset **more than 8 times over by developing nations.**

U.S. and Global Carbon Emissions Projections (million metric tons)



Source: EPA Carbon Regulation Proposal, pg 547-548, and www.eia.gov/forecasts/leo/table21.cfm

National Coal Council – Reliable & Resilient: The Value of Our Existing Coal Fleet

APPENDIX A

Turbine Upgrade or Efficiency Improvement Projects Cited in NSR Enforcement Initiative

This list is limited to turbine upgrades or replacements – the list would be much longer if improved materials of construction and improved designs of heat transfer surfaces were included.

1. Turbine Upgrade or Efficiency Improvement Projects Cited in NSR Enforcement Initiative

- *United States v. Duke Energy Corp.*, No. 00-cv-01262 (M.D.N.C. Dec. 22, 2000) (GE Dense Pack turbine upgrades at Belews Creek Units 1 and 2 and Marshall Unit 3);
- *New York v. Niagara Mohawk Power*, No. 02-CV-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶ 202 (“upgraded the turbine” on Huntley Unit 63 in 1987), ¶ 323 (“replaced the turbine” on Huntley Unit 67 in 1991);
- *United States v. East Kentucky Coop.*, No. 04-34-KSF, Compl. (E.D. Ky. Jan. 28, 2004), ¶ 60 (“replacement or renovation ... of major components of the ... turbine at the unit” on Dale 4 in 1995-1995), ¶ 76 (“replacements or renovations of major components of the ... turbine” on Dale 3 in 1996);
- *Sierra Club v. Portland General Electric*, No. 08-cv-01136, Am. Compl. (D. Or. Nov. 29, 2010), ¶ 134 (“a plant turbine upgrade” at Boardman in 2003);
- *United States v. Ameren Missouri*, No. 4:11-cv-77, Am. Compl. (E.D. Miss. June 28, 2011), ¶ 67 (“associated turbine replacements” at Rush Island Unit 1 in 2001-2002), ¶ 73 (“associated turbine replacements” at Rush Island Unit 2 in 2003-2004);
- *Conservation Law Foundation, Inc. v. Public Service of New Hampshire*, No. 11-cv-00353, Compl. (D.N.H. July 21, 2011), ¶ 49 (“removed a high pressure/intermediate pressure turbine, and replaced it with a new HP/IP turbine” at Merrimack Unit 2 in 2008);
- *Dine Citizens Against Ruining Our Environment v. Arizona Public Service Company*, No. 1:11-cv-889, Am. Compl. (D.N.M. Jan. 6, 2012), ¶ 48 (“replacement of the high pressure turbines” at Four Corners Units 4 and 5 in 2007), *id.* (“Plaintiffs are informed and believe ... that these high-pressure turbine upgrades increased the design-level heat input rate of each of these units, thereby increasing each unit’s generating capacity and its potential to emit air pollution.”);
- *United States v. Dairyland Power Coop.*, No. 12-cv-462, Compl. (W.D. Wisc. June 28, 2012), ¶ 38 (“upgrading of the turbine at the J.P Madgett Unit in 2004”);
- *Sierra Club v. PPL Montana LLC*, No. 1:13-cv-32, Am. Compl. (D. Mont. Sept. 27, 2013), ¶ 55 (“Replacement of the Low Pressure Turbine” on Unit 3 in 2011), ¶ 57 (“High Pressure/Intermediate Pressure Turbine Replacement” at Unit 2 in 2008), ¶ 58 (“High Pressure Turbine Replacement” at Unit 3 in 2007), ¶ 59 (“High Pressure Turbine Replacement” at Unit 4 in 2006), ¶ 60 (“Replacement of the High Pressure and Intermediate Pressure Turbines” at Unit 1 in 2006).

National Coal Council – Reliable & Resilient: The Value of Our Existing Coal Fleet

2. Standard Turbine Overhauls or other Turbine Projects Cited in NSR Enforcement Initiative

- *United States v. Cinergy*, No. IP99-1693, Third Am. Compl., (S.D. Ind. June 29, 2006) at ¶ 172 (replacement of “turbine blades” on Beckjord Unit 6 in 1994);
- *United States v. Duke Energy Corp.*, No. 00-cv-01262, Compl. (M.D.N.C. Dec. 22, 2000), ¶ 32 (“turbine overhaul” at Allen Unit 5 in 2000), ¶ 60 (“turbine overhaul” at Allen Unit 4 in 1998), ¶ 195 (“turbine rehabilitation” at Cliffside Unit 4 in 1990);
- *Sierra Club v. Dayton Power & Light, Inc.*, No. C2-04-905, Compl. (S.D. Ohio Sept. 21, 2004), ¶ 43 (“overhaul of the turbine” on Stuart Unit 1 in 1980);
- *United States v. American Electric Power*, No. C2-05-360, Compl. (S.D. Ohio Apr. 8, 2005), ¶ 97 (“replacement of the low pressure turbine rotor” on Conesville Unit 5 in 1997), *id.* (“replacement of the low pressure turbine rotor” on Conesville Unit 6 in 1997);
- *Sierra Club v. PPL Montana LLC*, No. 1:13-cv-32, Am. Compl. (D. Mont. Sept. 27, 2013), ¶¶ 53 (“Low Pressure Turbine Overhaul” at Unit 1 in 2012), *id.* (“Turbine/Generator Base Overhaul” at Unit 1 in 2012), ¶ 54 (“Turbine Generator Base Overhaul” on Unit 2 in 2011), ¶ 55 (“Turbine Generator Base Overhaul” on Unit 3 in 2011), ¶ 55 (“Intermediate Pressure Turbine Overhaul” on Unit 3 in 2011), *id.* (“Turbine/Generator Base Overhaul” on Unit 3 in 2011), ¶ 56 (“LP1 & LP2 Turbine Rebuild” at Unit 4 in 2009), *id.* (“Low Pressure Turbine” at Unit 4 in 2009), *id.* (“Turbine/Generator Base Overhaul” at Unit 2 in 2008), *id.* (“Low Pressure Turbine Overhaul” at Unit 2 in 2008), ¶ 59 (“Intermediate Pressure Turbine Overhaul” at Unit 4 in 2006).



Mike Nasi

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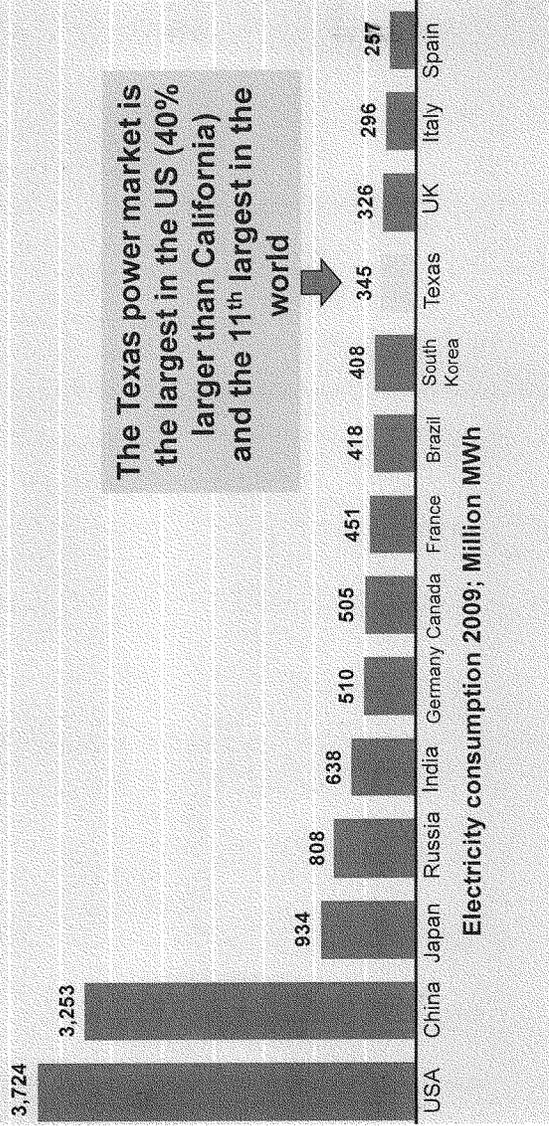
An Assessment of the Impact of EPA's 111(d) Rule (a.k.a. "Clean Power Plan") on Texas

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July 7, 2014



Population, Industry, & Climate Make the Texas Power Market... *“Like a Whole Other Country”*



NO MEGAWATTS TO SPARE: Texas Uses a Diverse Range of Fuels, Including Coal, to Keep Reliability Up & Cost Down

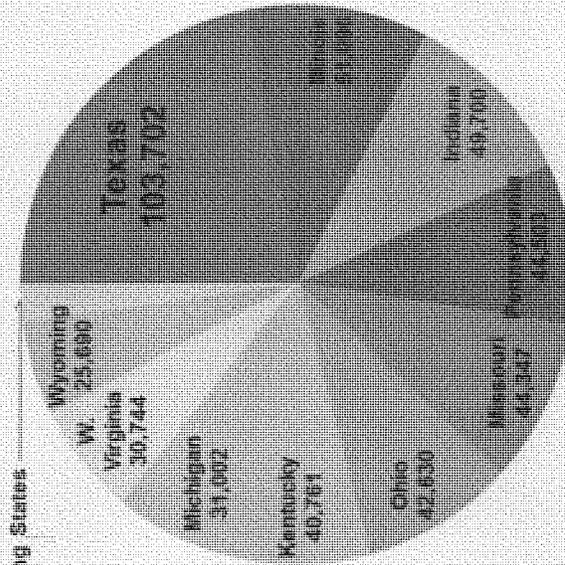
- Texas uses more energy than any other state in the nation, almost as much as the next two states combined (California and Florida).
- *Nearly half of Texas' electricity use is for industry and manufacturing, which includes the oil & gas and petrochemical industries (more than next 3 states combined).*
- To keep costs down and production up, Texas uses coal to maintain fuel diversity – accounts for 37-40% of grid



Source: Energy Consumption by End-Use Sector. Ranked by State, 2010. Energy, U.S. EIA

Because of its Size, Texas Consumes Twice as Much Coal as Any other State

U.S. THERMAL COAL CONSUMPTION (tons)

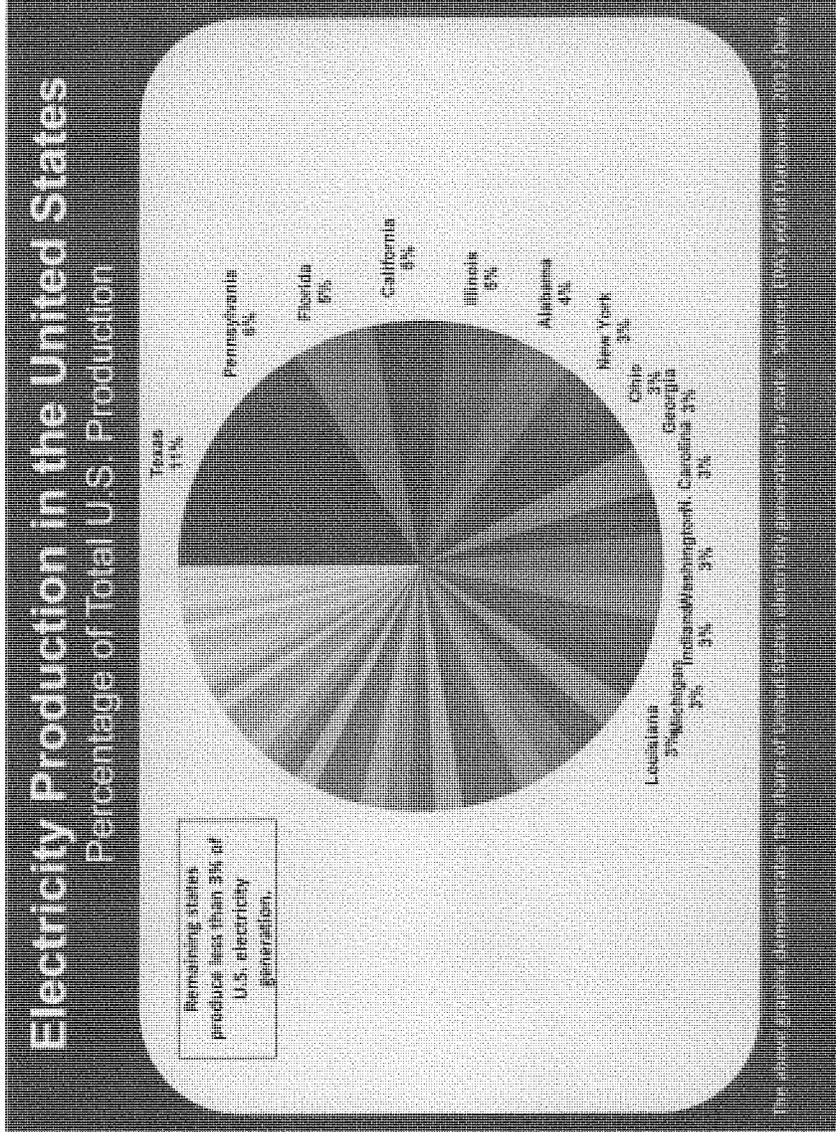


Source: U.S. Energy Information Administration, Annual Coal Report, 2012. In order to reduce the impact of market swings, coal consumption is based on an average of the coal consumption for 2011 and 2012.

Texas Carrying Disproportionate Burden of EPA Carbon Reductions

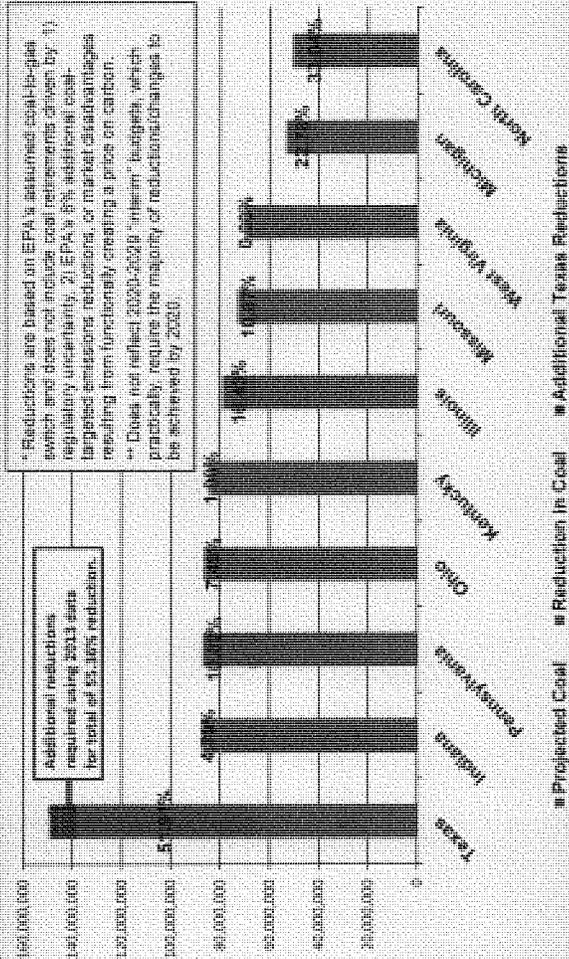


- A legitimate claim could be made that Texas should not have to reduce a proportionate share because it produces a majority of our nation's fuels, chemicals and goods (we do everyone's dirty work)
- Yet, when you compare the next two slides, you can see that EPA is not just making Texas carry its share, but almost TWICE its proportionate share (11% of U.S. generation and 18-25% of CO2 reductions)



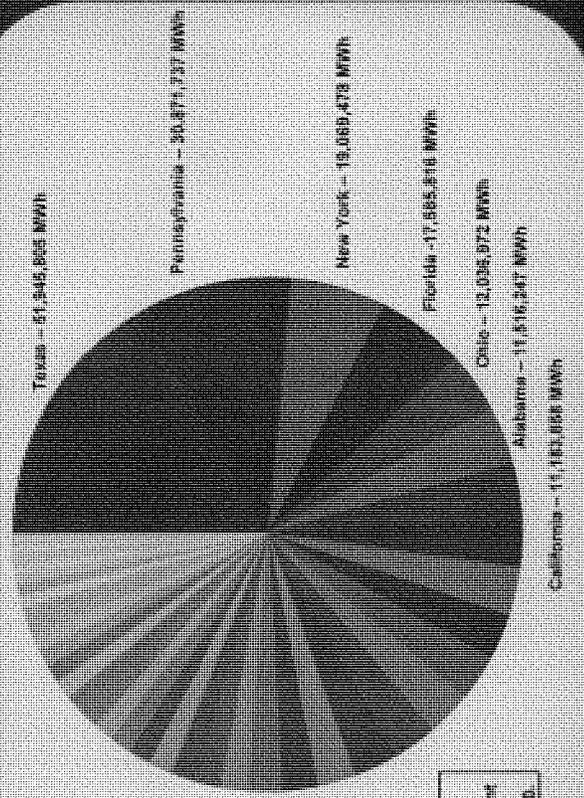
EPA's Modeled Reductions in Coal Generation

Comparison of Top 10 Generators of Coal Electricity – Final 2030 Target



Modeled reductions are shown in megawatt-hours (MWh), comparing 2012 data to EPA's projected 2030 target. Texas is projected to reduce coal generation from 138,705,133 MWh in 2012 to 66,699,255 MWh in 2030 – a reduction of 51.21%. In 2013, Texas coal generation actually totaled 149,414,144 MWh, which would result in a difference of 92,714,889 MWh (62.08%) to meet EPA's 2030 target.

EPA's Modeled Increases in Renewable Electricity

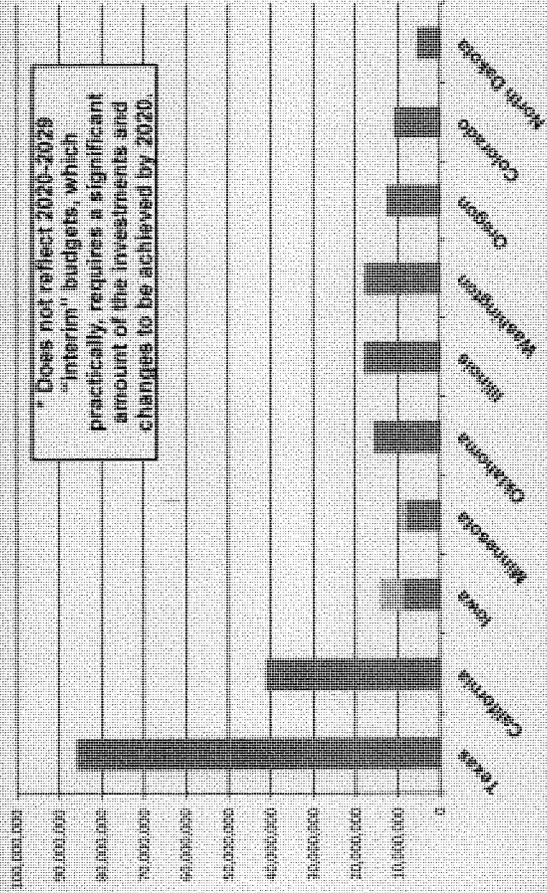


Remaining state increases are all below 10,000,000 MWh.

* Does not reflect 2020-2025 "energy" budgets, which typically require a significant amount of the investments and changes to be achieved by 2020.

Modeled increases are in megawatt-hours (MWh) comparing 2012 data to EPA's projected 2030 target. Texas is projected to go from 34,016,537 to 65,962,502 MWh in RE - a 100% increase. The above graphic does not include Iowa, Maine, Minnesota, and South Dakota, states in which EPA's model anticipates reductions in RE.

EPA's Modeled Increases in Renewable Electricity (Top Ten Producers)



* Does not reflect 2020-2028 "interim" budgets, which practically, requires a significant amount of the investments and changes to be achieved by 2020.

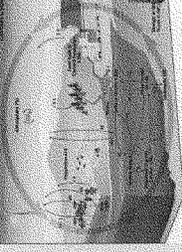
■ 2012 RE ■ Increase in RE ■ Decrease in RE

Modeled increases are in megawatt-hours (MWh) starting 2012 data to EPA's 2028 target. Texas is projected to go from 94,507 to 104,527 MWh in RE. Illinois, Nevada, California, and Washington are only projected to increase renewable electricity generation by 31%. From 2012 to 2028, EPA's model projects that Texas will increase renewable electricity generation by 114.3% while California is projected to increase by 8%.



Texas WILL Fight EPA's Illegal Re-Engineering of our Fleet

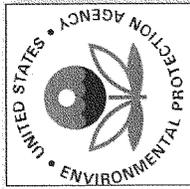
- EPA claims states have “flexibility” but the reality of mandated state budgets strictly limit options available to states
- Majority of the rule’s reductions come “outside the fence” by assuming fuel-switching & build-out of renewables & efficiency
- Disparate impact on Texas will strike at the heart of the U.S. production of fuels, chemicals, and manufactured goods.
- SIP disapprovals & FIPs could result in unprecedented clash between EPA and states (“Come and Take it”)
- Immediate task is to build case for irreparable harm & political intervention to keep the rule from coming into effect



EPA'S Carbon Rule is "All Pain – No Gain"

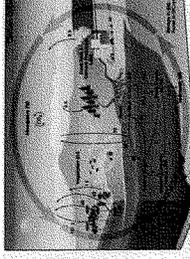
(based on EPA analysis/methodology in light duty vehicle rule and assuming accuracy IPCC projections):

- Addresses only 0.18% of world's CO₂ emissions.
- Global temperature reduced by only 0.01 degrees C
- Mitigation of 0.016 inch of sea level rise; the thickness of 4 sheets of paper or 1/3rd the thickness of a dime)



No Gain

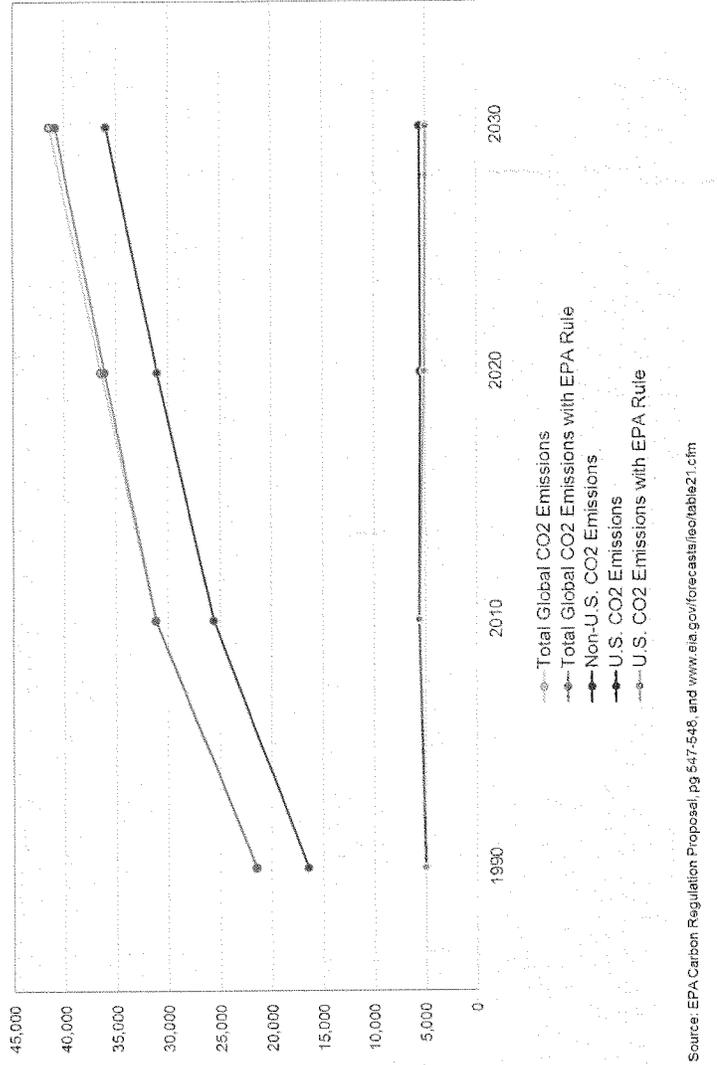
(due to World energy realities)



- Non-U.S. CO₂ emissions are projected to increase 55 percent between 2010 and 2040.
- Between 2011 and 2030, annual non-U.S. power sector carbon emissions are projected to increase by 4,692 million tons
- BOTTOM LINE: 111(d) rule reductions will be offset **more than 8 times over by developing nations.**

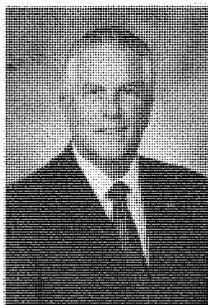
U.S. and Global Carbon Emissions Projections

(million metric tons)



Source: EPA Carbon Regulation Proposal, pg 547-548, and www.eia.gov/forecasts/leo/table21.cfm

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 LUMMIS. I thank the witness and now recognize our third witness, Dr. Cash.

**TESTIMONY OF MR. DAVID CASH, COMMISSIONER,
MASSACHUSETTS DEPARTMENT OF
ENVIRONMENTAL QUALITY**

Mr. CASH. Thank you very much, Chair Lummis and Ranking Member Johnson and other Members of the Science, Space, and Technology Committee for the opportunity to provide comments on EPA's proposed Clean Power Plan.

My name is David Cash. I am the Commissioner of the Massachusetts Department of Environmental Protection, and prior to this, I was Commissioner of our State's Public Utilities Commission and focused on grid reliability and cost for ratepayers. In total, I have worked in State Government for ten years, always at the nexus of energy, environment, and economic development and always with the goal of creating a thriving State for families, communities, and businesses.

Let me start with a story of dramatic change. Eight years ago there were three megawatts of installed solar power Massachusetts. Today, there are over 500 megawatts. Eight years ago there were three megawatts of installed wind power. Today, there are over 100 megawatts. Today, there are over 5,000 companies and over 80,000 people employed in the clean energy economy in our State, and for the last four years, clean energy job growth has been between six percent and 12 percent per year.

Today, Fortune 500 companies and mom-and-pop shops, residential customers in cities and towns are taking advantage of our energy efficiency and renewable energy programs and saving billions of dollars. For a company this may mean hiring new people or expanding R&D or marketing. For a town, maybe new teachers or firefighters can be hired. For families across the Commonwealth, they have more money in their pockets that they are not spending on energy. Over the last several years we have invested over \$1 billion in energy efficiency and expect a return of \$3-\$4 billion.

The arc of this story is simple. Wise environmental protection and robust economic development can and should go hand-in-hand. In fact, since 1990, our carbon emissions in Massachusetts have declined by 40 percent while our economy has grown by almost 70 percent.

[Slide]

Mr. CASH. If you will take a look at the graph that is shown on the screens now, take a look particularly at the bottom line, the red line that shows our greenhouse gas emissions in the power sector declining by 40 percent, most of that in the last 8 to ten years, but over the last 20 years by 40 percent. At the same time, look at the top line. That shows our economic growth of over 70 percent. You can see some other indicators in the middle, but the story is a powerful story that shows that environmental protection can go hand-in-hand with economic development.

The Administration of Governor Deval Patrick has launched a clean energy revolution in our State introducing forward-looking policies and wide-ranging regulatory reform and regional partnerships. One of his first actions in office was to bring all of the energy

and environment agencies under one umbrella and add a mandate to link environmental protection and economic development.

We have approached EPA's 111(d) rule with exactly this comprehensive perspective understanding how these regulations will impact the power sector, energy prices, the environment, and economic development.

Our conclusion is that implementation of 111(d) will mirror what has happened in the last eight years in Massachusetts and other States but on a national scale. The private sector will respond, sparking innovation, entrepreneurship, energy cost savings, job growth, customer choice, and opening up global markets for U.S. products and services.

In preparing the Clean Power Plan, EPA conducted an unprecedented amount of outreach to States and other key stakeholders recognizing the need for flexibility in the diversity of state-led initiatives and programs. One such successful program is the multistate Regional Greenhouse Gas Initiative, RGGI. RGGI is a regional market-based emissions reduction program for the power sector, in other words, setting a standard and letting the market work. In the Clean Power Plan EPA recognizes regional market-based programs as acceptable compliance mechanisms. This is critical because the evidence is clear. RGGI and the RGGI experience has demonstrated that we can cost effectively realize environmental and economic goals while maintaining electricity grid reliability.

The RGGI States have experienced a 40 percent reduction in power sector emissions since 2005 while our regional economy has grown by seven percent, adjusted for inflation. Of course, these significant pollution reductions are due to a combination of factors including market forces, the greater supply of natural gas, and other state clean energy policies, but RGGI has clearly been a driver as well.

A recent independent analysis by the Analysis Group concluded that investments for the first RGGI control period in energy efficiency, renewable energy, and other programs are adding \$1.6 billion of net economic value to our region. In the RGGI region, these emissions reductions and types of strategic investments by Massachusetts and other RGGI States occurred while customer rates were dropping. Our original prediction, as we began developing RGGI, where that electricity rates would increase by 1 to two percent. Instead, region-wide they have declined by 8 percent.

I know that we are not Kentucky or West Virginia or other States that are facing difficult challenges, but I also know that the low-hanging fruit of energy efficiency is available everywhere and grabbing that low-hanging fruit means savings for customers, local jobs, and greenhouse gas emission reductions.

EPA should be commended for developing the proposed rule that recognizes the diversity among States and provides a flexible approach to compliance. By providing the States with this flexibility, Massachusetts believes the plan will not only aid in the effort to reduce carbon pollution but will also help our nation develop an advanced infrastructure that delivers cleaner air, smarter energy use, and an improved economy and local jobs.

Thank you and I am happy to answer questions.

[The prepared statement of Mr. Cash follows:]

House Committee on Science, Space & Technology

Testimony on EPA Clean Power Plan

Dr. David W. Cash
Commissioner
Massachusetts Department of Environmental Protection

July 30, 2014
Washington, DC

Thank you Chair Lamar Smith, Ranking Member Eddie Bernice Johnson, and other members of the Science, Space, and Environment Committee for the opportunity to provide comments on EPA's proposed Clean Power Plan. My name is David Cash and I am the Commissioner of the Massachusetts Department of Environmental Protection. Prior to this position, I was a Commissioner of our state's public utilities commission for three years focusing on grid reliability and protection of ratepayers. In total, I have worked in state government for ten years, always at the nexus of energy, environment and economic development.

Let me start with a story of dramatic change:

8 years ago, there was 3MW of installed solar power – today there is over 500MW in Massachusetts.

8 years ago, there was 3MW of installed wind power – today there is over 100MW.

Today there are over 5,000 companies and over 80,000 people employed in the clean energy economy in our state, and for the last 4 years, clean energy job growth has been between 6% and 12% per year.

Today, Fortune 500 companies and mom & pop shops, residential customers and cities and towns are taking advantage of our energy efficiency programs and collectively saving billions of dollars. For a company, this may mean hiring new people or expanding R&D or marketing; for a town maybe new teachers or fire fighters can be hired; for families across the Commonwealth, they have money in their pockets that they are not spending on energy. Over the last several years we've invested over \$1B for energy efficiency and expect a return of \$3-4B.

The arc of this story is simple: wise environmental protection and robust economic development can, and should, go hand in hand. In fact, since

1990, our carbon emissions have declined by 40%, while our economy has grown by almost 70%. [See Graph 1 in the Appendix].

The Administration of Governor Deval Patrick has launched a clean energy revolution in our state, introducing forward-looking policies and wide-ranging regulatory reform and regional partnerships. One of his first actions in office was to bring all of the energy and environment agencies under one umbrella, and add a mandate to link environmental protection and economic development. We have approached EPA's 111(d) rule with exactly this comprehensive perspective, understanding how these regulations will impact the power sector, energy prices, emissions and economic development.

Our conclusion is that implementation of 111(d) will mirror what has happened in the last 8 years in Massachusetts and other states but on a national scale: the private sector will respond, sparking innovation, entrepreneurship, energy cost savings, job growth, customer choice and opening up global markets for U.S. products and services.

While Massachusetts and many other states have begun to see the opportunities of addressing climate change, following the Supreme Court's ruling in 2007 that upheld the requirement that EPA must regulate greenhouse gases, EPA has provided a national path forward to seize clean energy opportunities nation-wide.

Massachusetts welcomes the release of the Clean Power Plan, which seeks to reduce carbon dioxide (CO₂) emissions from power plants under section 111(d) of the Clean Air Act. This proposed rule is a very important step forward towards the development of an advanced energy infrastructure that delivers cleaner air, smarter energy use, and job growth.

EPA conducted an unprecedented amount of outreach to states and other key stakeholders during the development of this proposed rule, recognizing the need for flexibility and the diversity of initiatives and programs that states are currently pursuing.

One such successful program is the multi-state Regional Greenhouse Gas Initiative. RGGI is a regional market-based carbon emissions reduction program for the power sector. In the Clean Power Plan EPA recognizes

regional market- based programs as acceptable compliance mechanisms. This is critical because the evidence is in: the RGGI experience has demonstrated that we can cost-effectively realize environmental and economic goals while maintaining electricity grid reliability.

The RGGI states have experienced a 40 percent reduction in power sector carbon dioxide pollution since 2005 as our regional economy has grown by 7% (adjusted for inflation). Of course, these significant pollution reductions are due to a combination of factors including market forces, the greater supply of natural gas, and other state clean energy policies, but RGGI has clearly been a driver as well. Through 2013 the RGGI states have invested more than \$950 million in RGGI proceeds in energy efficiency, clean and renewable energy, and other strategic energy programs. In Massachusetts, we have invested more than \$240 million through last year, with approximately 90 percent of these investments directed toward energy efficiency projects. A recent independent analysis by the Analysis Group concluded that investments from the first RGGI control period are adding \$1.6 billion net economic value to our region. In the RGGI region, these types of strategic investments by Massachusetts and the other RGGI states occurred while customer rates were dropping. Our original predictions, as

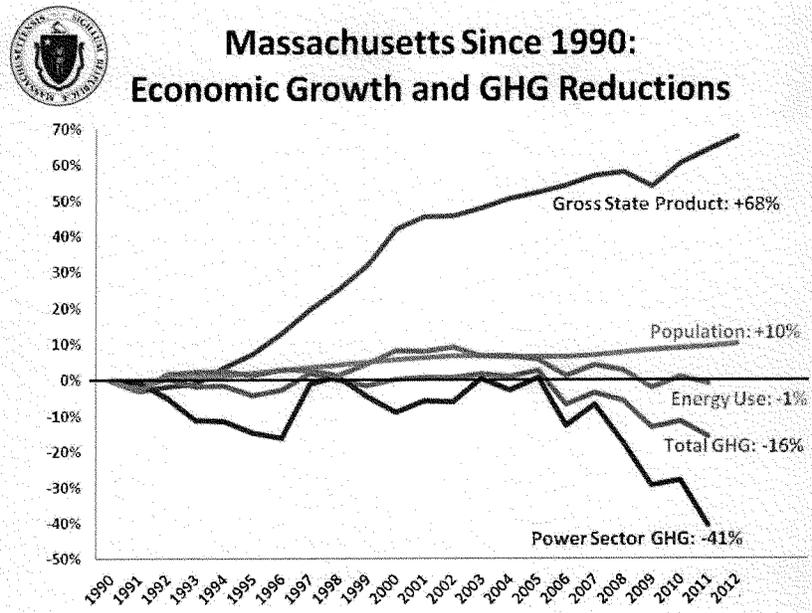
we began the developing RGGI, were that electricity rates would increase by 1-2% -- instead, region-wide they've declined by about 8%. All while emissions dropped by 40%, the economy grew by 7%, and grid reliability was enhanced through lower demand-related stress and solar power which produces electricity during peak demand periods.

We believe that ours and many other states' experience demonstrates that flexible carbon emissions reduction programs, coupled with other state policies, can prevent harmful pollution from entering the atmosphere, while also supporting a broad range of economic benefits, from lower energy bills, mitigation of price volatility and job growth. EPA should be commended for developing a proposed rule that recognizes the diversity amongst states and provides a flexible approach to compliance. By providing the states with this flexibility, Massachusetts believes the plan will not only aid in the effort to reduce carbon pollution, but will also help our nation develop an advanced energy infrastructure that delivers cleaner air, smarter energy use, an improved economy and new local jobs.

Thank you.

Appendix

Graph 1



Source: MassDEP Nov. 2014

David W. Cash was appointed on March 26, 2014 as Commissioner of the Massachusetts Department of Environmental Protection (MassDEP) by Governor Deval Patrick and his Secretary of Energy and Environmental Affairs, Richard K. Sullivan Jr.

Dr. Cash brings to MassDEP a wealth of experience in environmental, energy and regulatory sectors. He most recently held the position of Commissioner at the Massachusetts Department of Public Utilities (DPU) where he helped lead efforts to modernize the grid, expand the deployment of energy efficiency and renewable energy, and empower customers in their energy decisions.

Prior to his work at the DPU, Dr. Cash was the Undersecretary for Policy in the Massachusetts Executive Office of Energy and Environmental Affairs (EEA). In this role, Dr. Cash advised the EEA Secretary on an array of issues, including climate change, energy, land management, water management, oceans, wildlife and fisheries, air and water quality, environmental and energy dimensions of transportation, and waste management. He was one of the architects of clean energy legislation and implementation in the first term of the Patrick Administration, including the Green Communities Act, the Global Warming Solutions Act, the Green Jobs Act and the Clean Energy Biofuels Act. As part of this work, he led the Secretariat's effort in developing the Massachusetts Clean Energy and Climate Plan for 2020, which provides a roadmap of policies and programs that will lower energy costs, create clean energy jobs and reduce greenhouse gas emissions.

Prior to working for the Commonwealth, Dr. Cash was a research associate at the John F. Kennedy School of Government at Harvard University, and a Lecturer in Environmental Science and Public Policy. He also taught science in the Amherst, Massachusetts public schools from 1990-1993. He received a Ph.D. in Public Policy from the Kennedy School at Harvard in 2001, and a B.S. in biology from Yale University in 1987.

He lives in Newton with his wife Annie and their two high-school-age children, Sophie and Eliza.

Chairman LUMMIS. I thank the gentleman and now recognize our final witness, Mr. Sopkin, for—is it Sopkin?

Mr. SOPKIN. It is Sopkin.

Chairman LUMMIS. Okay. For five minutes.

**TESTIMONY OF MR. GREGORY SOPKIN,
PARTNER, WILKINSON, BARKER, KNAUER LLP**

Mr. SOPKIN. Thank you. And it is an honor to be here from the great State of Colorado where we don't always win Super Bowls but we have a really balanced energy portfolio.

From 2003 to early 2007 I was the Chairman of the Colorado Public Utilities Commission. I am approaching this testimony primarily from a State perspective, what States are looking at and having to implement this EPA rule.

We have written a white paper. My partner Ray Gifford, who also was a Chairman of the Colorado PUC, and I wrote a white paper about the logistical political and practical difficulties States are going to have in implementing this EPA rule.

I also have to give a shout out to our associate Matt Larson who had a big hand in offering this and had a baby boy yesterday. And we as a compassionate firm gave him the day off yesterday.

We wrote this paper because of our experience as State Commissioners in working with state environmental departments and state legislatures. Some of the white paper's findings are, first, the EPA's proposed carbon reduction rule creates a carbon-driven energy resource planning process that is unlike any other Clean Air Act regulatory regime. The proposed building blocks look strikingly like integrated resource planning, which is a function that has traditionally been performed by States that have the expertise and manpower to delve into those matters deeply. Carbon IRPs or their equivalent will almost certainly require state legislation regardless of whether a State is vertically integrated or deregulated States.

The time constraints for States in implementing this rule are potentially insurmountable. States have little time, particularly given the need to pass legislation, to make crucial and far-reaching decisions regarding this proposed rule. The decision points include whether to act individually or on a multistate basis and determining what state agencies should take the lead in implementing and overseeing this process.

The scope of the EPA rule creates implementation—excuse me—creates a serious risk of EPA takeover of state resource planning. If a State implementation plan is deemed inadequate by EPA, then it is up to the EPA to then devise the plan for States to follow.

Next, a carbon adder for environmental dispatch is likely a necessary implementation feature regardless of market structure. That means that there has to be something similar to a carbon tax that is imputed upon the regulatory structure.

Next, all generators must participate in the carbon IRP process from investor-owned utilities to non-jurisdictional entities not traditionally subject to regulation. That includes rural cooperatives and municipal utilities who have never had to submit a resource plan before are now going to be subject to regulation of some state agency over their resource planning.

Central resource planning will return to restructured, competitive States. In restructured States, States have opted to use competition as the method for lowest-costing electricity and to determine their optimal resource mix. That will now give way to carbon planning.

Multistate SIPs are accompanied by legal and practical hurdles, including the potential need for a congressionally approved interstate compact. The EPA approval criteria requiring adequate enforcement mechanisms implicate the United States Constitution Compact Clause because enforcement can and should be on an interstate basis to address inevitable rivalries that will develop in an interstate agreement between States.

In my view of the EPA's Section 111(d) proposal fundamentally transforms state commission sovereignty over resource planning in determining what is best for electric consumers. I have seen first-hand the effects of electric reliability problems and high cost generation in my home State, Colorado. The EPA has repeatedly invoked the refrain "flexibility," meaning we don't care how your State reaches that prescribed carbon reduction level, but you must get there and you have one year to submit a plan to do it. This is analogous to saying you have 6 gallons of gas to get from San Francisco to New York City in 24 hours but you have the flexibility regarding your mode of transportation. One could be forgiven for not thinking that that is flexibility. The problem here is that EPA has declined to offer flexibility on the all-important issues of cost, capacity, and feasibility. In fact, EPA has implicitly declined to offer the State flexibility inherent in its very own Section 111(d) implementing regulations.

The remainder of my written testimony is the contents of the white paper. I look forward to your questions.

[The prepared statement of Mr. Sopkin follows:]

Testimony before the House Committee on Science, Space, and Technology

EPA's Carbon Plan: Failure by Design

Wednesday, July 30, 2014

Testimony of Greg Sopkin
On Behalf of Wilkinson, Barker, Knauer LLP

Members of the Committee on Science, Space and Technology:

Thank you for the opportunity to offer testimony on the Existing Source Performance Standards being considered by the U. S. Environmental Protection Agency (EPA) under Section 111(d) of the Clean Air Act – it is an honor to be here from the great State of Colorado.

From 2003 to early 2007, I was Chairman of the Colorado Public Utilities Commission, which regulates investor-owned electric utilities. My testimony is focused on a white paper written by myself and my partner Ray Gifford, who also was a Chairman of the Colorado Public Utilities Commission. We wrote the paper because of our experience as state commissioners and working with the state environmental department and state legislature on regulatory matters. We identified several political, logistical, and practical problems that states will have implementing EPA's proposed rules. Some of the white paper's findings are:

The EPA's proposed Section 111(d) carbon reduction rule creates a carbon-driven energy resource planning process that is unlike any other Clean Air Act regulatory scheme. The proposed building blocks look strikingly like integrated resource planning (IRP), a function traditionally left to the states without federal oversight. It creates a novel 'Carbon IRP' for the states to implement.

Carbon IRPs, or their equivalent, will almost certainly require state legislation, regardless of whether a state is vertically-integrated or deregulated. States will need to devise institutional arrangements between the state PUC and state environmental regulator to implement carbon-driven resource planning.

The time constraints are severe and potentially insurmountable. States have little time, particularly given the need for state legislation, to make crucial and far-reaching decisions regarding EPA's proposed rule. These decision points include whether to act individually or on a multi-state basis, and determining what state agency or agencies should implement and oversee a Carbon IRP-like process.

The scope of the rule and implementation difficulties creates a serious risk of EPA takeover of state resource planning. State Implementation Plans (SIPs) deemed inadequate by EPA under its evaluation criteria will be superseded by an EPA-drafted Federal Implementation Plan (FIP). The breadth of the rule creates a plausible scenario whereby EPA, not the state utility regulator, is indirectly shaping and approving IRPs.

A carbon adder is likely a necessary implementation feature regardless of market structure. This applies in vertically-integrated states because a carbon adder must be **included in any** modeling. In deregulated states and/or wholesale markets, a carbon adder is needed to implement "environmental dispatch protocols."

All generators must participate in the Carbon IRP process, from investor-owned utilities to non-jurisdictional entities not traditionally subject to regulation. Rural cooperatives and municipal utilities will be subject to an entirely new level and scope of jurisdiction over their

resource planning activities. This will require new state legislation in many states and also increase compliance costs for these non-jurisdictional entities.

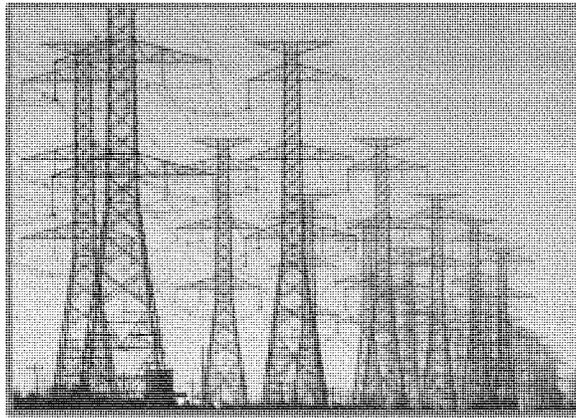
Central resource planning will return to restructured, competitive states. These states opted for competitive generation as a means to lower costs and achieve optimal resource mixes through competition instead of centralized resource planning by state utility commissions or similar entities.

Multi-state SIPs are accompanied by legal and practical peril, including the potential need for a Congressionally-approved interstate compact. Multi-state plans may be attractive in some regions, but the practical hurdles are significant. First, EPA SIP approval criteria requiring adequate enforcement mechanisms implicate the Compact Clause because enforcement can and should be on an interstate basis. Second, states should and will insist upon interstate enforcement mechanisms to address inevitable rivalries that develop given the interstate nature of the electric grid.

The remainder of my written testimony is the contents of the white paper. I encourage you to review it, and look forward to your questions – thank you.

State Implementation of CO₂ Rules

*Institutional and Practical Issues with State and
Multi-State Implementation and Enforcement*



A White Paper

Release 1.0 – July 2014

Raymond L. Gifford

Gregory E. Sopkin

Matthew S. Larson

Executive Summary

The proposed rule implicates potentially impossible timelines. States have relatively little time to make crucial decisions regarding EPA's proposed rule, including whether to act individually or on a multi-state basis, which of four state plan pathways to take, what state agency(ies) should be responsible to implement a Carbon IRP-like process, how any ISOs or RTOs operating within the state will play a role, and what enforcement and corrective action measures are necessary to ensure compliance with the proposed rule.

'Carbon IRPs' will require new institutional arrangements and state legislation. States will need to devise institutional arrangements, which almost certainly will require new legislation, between the state PUC and state environmental regulator to implement carbon-driven resource planning.

All EGUs need to be in the room for a Carbon IRP process to be effective – including non-jurisdictional entities not traditionally subject to regulation. State plans will need to encompass all electric generation units, including those owned or operated by current non-state jurisdictional entities like rural cooperatives and municipal utilities. To the extent a state SIP relies on energy efficiency or demand response, all distribution utilities will need to be brought within carbon IRP planning as well.

Carbon-driven planning may result in a soft reintegration of restructured markets. Restructured wholesale markets will require integrated carbon planning across the market areas to ensure adequate capacity and reliability.

Multi-state SIPs are attractive based on market structure but are accompanied by legal and practical peril. Multi-state plans may be attractive within many regions, particularly when coincident with ISO or RTO footprints.

Multi-state SIPs may breed rivalrous scenarios, and EPA SIP approval criteria will require interstate enforcement mechanisms, which implicate the Compact Clause. Because state interests will be potentially rivalrous, multi-state SIPs will need an enforcement mechanism and may well require congressionally-approved interstate compacts to satisfy EPA requirements of enforceability.

FIPs may put state regulators in awkward positions, including by forcing ultra vires actions. State SIPs that are adjudged by EPA to be inadequate in terms of enforceable, quantifiable and verifiable reductions of EGU CO₂ emissions equivalent to EPA's goals, and implementation of corrective actions, if necessary, will result in a FIP. A FIP creates legal issues of whether EPA has the authority to force state officials to enforce obligations they do not have authority to enforce under state law, and to engage in resource planning and direct system dispatch.

I. Overview

EPA’s proposed rule to regulate carbon dioxide emissions (“Section 111(d)” or the “CO₂ Emission Guidelines”) from electric generating units (EGUs), issued June 2, 2014, has triggered immediate analysis and commentary about the prudence and legality of EPA’s approach under the Clean Air Act. This White Paper approaches the proposed rule from the perspective of states, and focuses in particular on the institutional and practical challenges that states face in implementing the proposed rule.¹

To state our conclusion up front: There are manifold challenges and decisions for states, and between states, about how to implement the rule. In all conceivable scenarios, Section 111(d) implementation will require state legislation to erect new institutional arrangements for a state to consider a “Carbon Integrated Resource Plan” (Carbon IRP). In vertically-integrated states, non-jurisdictional generation and distribution operators like cooperatives and municipal utilities will need to be brought into the Carbon IRP process. Threshold institutional questions will also need to be answered. Will the Carbon IRP take place under the auspices of a public utilities commission or the state environmental regulator?² In states with restructured wholesale markets, there is a compelling rationale for states to enter into multi-state plans coincident with the wholesale market (RTO) territory. But even regionally, something resembling a Carbon IRP will be

The issues that must be debated and decided among and between states to determine what institutional structures must be in place to even begin deciding how the carbon reduction mandates will be reached must occur over the next several months, not years.

necessary, and adapting an “environmental dispatch” protocol will risk anointing winners and losers across states. Finally, the multi-state plan option implicates the need for interstate compacts, state legislation authorizing the compacts, and compliance with the Compact Clause of the U.S. Constitution.

Because it takes years for utilities and energy providers to plan and develop substantial changes to electricity generation portfolios - and additional time to obtain necessary state agency approval of these plans - EPA’s Section 111(d) implementation timeline is very short indeed. States must submit their enforceable State Implementation Plans (SIPs) by June of 2016 (absent an EPA grant of a 1- or 2-year delay), and the SIPs must demonstrate considerable carbon reductions by 2020. Therefore, the issues that must be debated and decided among and between states to determine what institutional structures must be in place to even begin deciding how the carbon reduction mandates will be reached must occur over the next several months, not years. These political, logistical, and jurisdictional issues may well prove complex and intractable enough to undermine the foundation for EPA’s Section 111(d) goals.

States must formulate SIPs under the Section 111(d) implementing regulations. The CO₂ Emission Guidelines are accompanied by numerous legal and technical memoranda, including a memorandum that addresses state-level compliance “plan pathways.” In its State Plan Considerations Technical

Support Document, EPA proposes four “state plan pathways”: (1) rate-based CO₂ emission limits; (2) mass-based CO₂ emission limits; (3) a state-driven portfolio approach; and (4) a utility-driven portfolio approach. A portfolio approach “would include emission limits for affected EGUs along with other enforceable end-use energy efficiency and renewable energy measures that avoid EGU CO₂ emissions.”

EPA generally addresses the role of existing programs and processes in the CO₂ Emission Guidelines, including resource planning processes:

¹ For purposes of this analysis, we do not question EPA’s legal authority to issue the rule, but rather what a state CO₂ regime will look like under Section 111(d) and the proposed implementing regulations.

² The U.S. Supreme Court recently denied a certiorari petition seeking review of a Missouri PSC decision denying Kansas City Power & Light cost recovery of FERC-approved transmission costs. Based on this, an investor-owned utility will likely insist on PUC involvement in Carbon IRP planning to ensure cost recovery of Carbon IRP planning decisions. See *State of Missouri ex. rel. KCP&L v. Missouri Public Service Commission*, 408 S.W. 3d 153 (Mo. App. 2013), cert. denied, 2014 WL 2921776 (June 30, 2014).

“States would be able to rely on and extend programs they may already have created to address the power sector. Those states committed to Integrated Resource Planning (IRP) would be able to establish their CO₂ reduction plans within that framework, while states with a more deregulated power sector system could develop CO₂ reduction plans within that specific framework.” Here, then, is the crux of the institutional and practical questions states must confront with this rule.

This White Paper proceeds in five parts: overall considerations for SIP development, SIP implementation in vertically-integrated states, SIP implementation in restructured states and within RTOs, multi-state SIP considerations, and tentative conclusions.

At the outset, we want to emphasize that this “Release 1.0” of the White Paper is meant to be iterative, to provoke comment, correction and disputation. As we contemplate the practical implementation of the rule, we foresee the issues detailed below, but also emphasize that a rule this

As we contemplate the practical implementation of the rule, we foresee the issues detailed below, but also emphasize that a rule this complex is difficult to get one’s mind around.

complex is difficult to get one’s mind around. The issues we raise and conclusions we reach, therefore, should be regarded as tentative and partial. We welcome feedback because we envision iteratively focusing and improving this White Paper in future releases. For now, we see a daunting set of institutional challenges for the states that will profoundly affect the implementation and effectiveness of the rule, and its effect on the nation’s electric system. These key issues and challenges include the need to:

- Pass enabling legislation to implement the proposed rule at the state level.
- Construct institutional arrangements between the

universe of regulators (public utility commissions (PUCs), environmental regulators, gubernatorial energy offices) in a state statutory and administrative context.

- Obtain and concentrate jurisdiction in the appropriate regulatory bodies over all affected entities, including current non-state jurisdictional entities like cooperatives and municipal utilities.
- Institute carbon-driven resource planning and dispatch in restructured markets to ensure adequate capacity and reliability.
- Structure enforceable and constitutional multi-state SIPs with interstate enforcement mechanisms, which may well require Congressionally-approved interstate compacts to satisfy EPA SIP approval criteria.

II. The Structure of the CO₂ Emission Guidelines and Key EPA Assumptions

a. Building Blocks and Performance Goals under the CO₂ Emission Guidelines

EPA’s proposed CO₂ Emission Guidelines limit CO₂ emissions from EGUs in every state save Vermont and the District of Columbia. The proposed guidelines require each state to devise its own enforceable state implementation plan to meet the CO₂ performance goal, *i.e.*, emission limit, established by EPA for the state.³

³ Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (June 18, 2014). In the proposed Table 1 to Subpart UUUU of 40 C.F.R. Part 60, EPA proposes interim and final goals for each state in pounds of CO₂ per net MWh. CO₂ Emission Guidelines at 643-645. The interim goals apply from 2020-2029, while the final goal applies in 2030. The interim goals as currently structured present a unique challenge for some utilities, as the 2020-2029 interim goal is “the simple average of the annual rates computed for each of the years from 2020 to 2029.” CO₂ Emission Guidelines at 355. In addition, “[t]o be approvable, a state plan must demonstrate that the emission performance of affected EGUs will meet the interim emission performance level on average over the 2020-2029 period.” CO₂ Emission Guidelines at 409. Part of the justification for the 2020-2029 interim goals is that “EPA recognizes the importance of ensuring that, during the proposed 10-year performance period (2020-2029) for the interim goal, a state is making steady progress toward achieving the required level of emission performance.” CO₂ Emission Guidelines at 411. The need for *de facto* ongoing compliance on a trajectory could be difficult for utilities that may want to engage in long-term system planning such that it may miss interim goals in some years but would ultimately

A state is free to determine how it will achieve the EPA-set CO₂ performance goal, but EPA made certain general assumptions, applied to all states, to calculate each individual performance goal.

EPA calculated the CO₂ performance goal using four "building blocks": (1) assuming a six percent heat-rate efficiency improvement to each existing coal-fired EGU; (2) assuming a 70 percent capacity utilization rate for combined-cycle gas-fired EGUs; (3) calculating a renewable portfolio standard (RPS) based on the average RPS of states in the same region of the country, and assuming usage of nuclear power plants based on existing and expected nuclear units; and (4) assuming a one and one-half percent per year reduction in electric usage through demand-side management (DSM) measures.

b. Illustrative Application of the Building Blocks

EPA relied on the four building blocks in establishing the CO₂ performance goal for each state. For example, EPA calculated the CO₂ performance goal for Georgia as follows: (1) all coal-fired EGUs will improve their respective heat rate by six percent; (2) dispatch to gas combined cycle (CC) units can be increased to 70 percent; (3) the state can continue utilizing existing nuclear plants and Southern Company will complete construction of the Vogtle 3 and 4 nuclear units; (4) statewide renewable energy power generation can and will increase from three to ten percent; and (5) statewide DSM levels (demand reduction) will increase from 1.8 to 9.8 percent. The EPA's interim (2020-2029) mandate for Georgia is a CO₂ emission reduction from 1,534 to 891 pounds of CO₂ per megawatt hour (CO₂/MWh), which represents a reduction of 41 percent; and its final (by 2030) mandate is a reduction to 834 CO₂/MWh. This represents roughly a 46 percent reduction from 2012 baseline emissions.

achieve compliance on average through specific actions taken all at one time or over a one- to two-year period just prior to the implementation of the final goal in 2030. This "less steady" strategy would still comply with the interim goals on average and utilities may wish to preserve this option.

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c. Must States Conform Resource Planning to Match the Building Blocks?

States are *not* required to overhaul the generation fleet to adopt assumptions used in the four building blocks; in other words, states do not necessarily have to reduce the heat rate of all coal-fired EGUs by six percent or increase gas CC dispatch to 70 percent. However, each state is ultimately responsible for achievement of its performance goal or, as discussed in more detail later in this paper, an aggregated multi-state performance goal. This is where EPA's "flexibility" talking point comes in, as states technically have flexibility to meet the performance goal as they see fit.⁴ States do not have "flexibility" to modify the CO₂ performance goal set by EPA.

III. State Considerations in Formulating SIPs

a. State Primacy and EPA's Proposed "Plan Pathways"

As referenced above, states have primacy and discretion in devising SIPs under the CO₂ Emission Guidelines.⁵ For example, although the state-promulgated "emission standards" are to be "no less stringent than the corresponding emission guideline(s)" issued by EPA, states may make a case-by-case

determination that a specific facility or class of facilities are subject to a less-stringent standard or longer compliance schedule due to: (1) cost of control; (2) a physical limitation of installing necessary control equipment; and (3) other factors making the less-stringent standard more reasonable.⁶ State-level

Each state is ultimately responsible for achievement of its performance goal or, as discussed in more detail later in this paper, an aggregated multi-state performance goal.

⁴ See, e.g., EPA Administrator Gina McCarthy, *Remarks Announcing Clean Power Plan, As Prepared*, (June 2, 2014) available at <http://vosemite.epa.gov/opa/admpress.nsf/8d49f7ad4bbcf4ef852573590040b7f6/c45baade030b640785257ceb003f3ac3f0penDocument> (mentioning the word "flexibility" eight times in speech announcing the CO₂ Emission Guidelines and stating "[t]his plan is all about flexibility. That's what makes it ambitious, but achievable. That's how we can keep our energy affordable and reliable. The glue that holds this plan together, and the key to making it work, is that each state's goal is tailored to its own circumstances, and states have the flexibility to reach their goal in whatever way works best for them.")

⁵ See generally 40 C.F.R. Part 60, Subpart B.

⁶ 40 C.F.R. § 60.24(f).

compliance “plan pathways” are discussed in a accompanying Technical Support Document (TSD) to the rule.⁷ The TSD details the states’ options:

- Rate-based CO₂ emission limits: “Rate-based emission limits would apply a lb CO₂/MWh emission limit to affected EGUs. Depending on a state’s approach, compliance flexibility could be provided through different mechanisms, such as averaging among affected sources, or the use of tradable credits for avoided CO₂ emissions resulting from end-use energy efficiency and renewable energy measures”⁸
- Mass-based CO₂ emission limits: “Mass-based emission limits would apply either an individual limit on CO₂ tons emitted from an affected EGU or establish a finite CO₂ emissions budget for a group of affected EGUs. The latter approach is typically implemented through a tradable allowance system. With mass-based emission limits, end-use energy efficiency measures that avoid EGU CO₂ emissions could be a major component of a state’s overall strategy for cost-effectively reducing EGU CO₂ emissions, but would be complementary to the enforceable state plan (i.e., not included as enforceable measures in a state plan). These actions could be used to help a state cost-effectively achieve the CO₂ emissions limits, or to achieve other policy goals, but CO₂ emissions performance would be assured through the enforceable limit on mass emissions from affected EGUs.”⁹
- Portfolio approach: “The second basic state plan approach uses a portfolio of actions, in which a state plan includes multiple programs and measures that are designed to achieve either a rate-based or mass-based emissions performance goal for affected EGUs [A] portfolio approach is distinguished from an emission limit approach by the fact that achievement of the full level of required emission performance for affected EGUs specified in the plan is not ensured through the

application of direct emission limits that apply to affected EGUs [A] portfolio approach implemented in a restructured state with retail competition will likely look quite different from one implemented in a state with vertically integrated, regulated electric utilities. This includes the process for developing the portfolio approach, the mechanisms for implementing it, the responsible parties, and the regulatory and legal relationships among parties and state regulators.”¹⁰

- State-driven portfolio approach: “A state-driven portfolio approach – rather than a utility-driven approach – is more likely to be adopted in a state with a restructured electricity sector Under a state-driven portfolio approach a mix of entities might have enforceable obligations under a state plan. This includes owners and operators of affected EGUs subject to direct emission limits, as well as electric distribution utilities, private or public third-party entities, and state agencies or authorities that administer end-use energy efficiency and renewable energy deployment programs or are subject to portfolio requirements.”¹¹
- Utility-driven portfolio approach: “Under a utility-driven portfolio approach, a vertically integrated utility would develop and implement a portfolio of measures designed to meet the rate-based or mass-based emission performance level for its affected EGUs specified in the state plan. This plan would likely be developed and approved through an IRP-like process overseen by the state public utility commission. If there is more than one rate-regulated electric utility in the state, the state might apportion the state emission performance level for affected EGUs among utilities Under a utility-driven portfolio approach, the entire suite of obligations under the plan would be enforceable against the utility company, which would also be an owner and operator of affected EGUs A similar approach could be taken by municipally owned utilities or utility cooperatives, which often

⁷ See EPA Office of Air and Radiation, *State Plan Considerations – Technical Support Document for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Docket ID No. EPA-HQ-OAR-2013-0602 (June 2014), available at <http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf>

⁸ *Id.* at 7.

⁹ *Id.* at 8.

¹⁰ *Id.* at 8-9.

¹¹ *Id.* at 9-10.

also engage in an IRP process. However, state public utility commissions often do not regulate these utilities. As a result, implementation of a portfolio approach by these entities would introduce practical enforceability considerations under a state plan.¹²

According to EPA, “[s]tates would be able to rely on and extend programs they may already have created to address the power sector. Those states committed to Integrated Resource Planning would be able to establish their CO₂ reduction plans within that framework, while states with a more deregulated power sector system could develop CO₂ reduction plans within that specific framework.”¹³ However, this generic statement belies the myriad complexities associated with building a CO₂-driven regulatory regime into preexisting, state- or region-level resource planning architecture.

b. Enforcement as a Prerequisite for EPA Approval

A SIP must be enforceable by a state or group of states as a prerequisite for EPA acceptance. Consistent with the history of the Clean Air Act and the SIP-driven compliance approach, EPA makes clear in the CO₂ Emission Guidelines that the ability to enforce emission standards is a key, if not the most important, element the agency will consider in evaluating SIPs. Enforcement is paramount under single state or multi-state SIPs, and applies across the board to any and all actions relied upon to achieve compliance with emission standards. EPA provides that:

In order for a state to devise an acceptable SIP, the necessary regulatory structures must be in place to enforce CO₂ reductions of EGUs. For a substantial percentage of EGUs across the U.S., these structures do not exist.

A state plan must include enforceable CO₂ emission limits that apply to affected EGUs. In doing so, a state plan may take a portfolio approach, which could include enforceable CO₂ emission limits that apply to affected EGUs as well as other enforceable measures, such as RE and demand-side EE measures, that avoid EGU CO₂ emissions and are implemented by the state or by another entity.

¹² *Id.* at 11-12.

¹³ CO₂ Emission Guidelines at 22.

...

The EPA is proposing to evaluate and approve state plans based on four general criteria: 1) enforceable measures that reduce EGU CO₂ emissions; 2) projected achievement of emission performance equivalent to the goals established by the EPA, on a timeline equivalent to that in the emission guidelines; 3) quantifiable and verifiable emission reductions; and 4) a process for biennial reporting on plan implementation, progress toward achieving CO₂ goals, and implementation of corrective actions, if necessary.¹⁴

In vertically-integrated states, investor-owned utilities are regulated by state PUCs, generally through integrated resource planning processes. Municipal and rural electric cooperative utilities, by contrast, are often “self-regulating” and autonomously determine their resource portfolios, with exceptions.¹⁵ In states that are all- or partially-restructured, independent system operators (ISOs) or RTOs help govern the electric system. However, generation in ISOs and RTOs is not subject to traditional IRP processes and can be owned by merchant generators or utilities.

c. The Need for New State-Level Regulatory Architecture

In order for a state to devise an acceptable SIP, the necessary regulatory structures must be in place to enforce CO₂ reductions of EGUs. For a substantial percentage of EGUs across the U.S., these structures do not exist.

With the possible exception of California, no states have expressly delegated regulatory authority to implement and oversee carbon-based resource planning, including enforcement and corrective action

¹⁴ CO₂ Emission Guidelines at 43-44, 46.

¹⁵ While many states exempt municipal utilities and cooperatives from PUC administrative regulation, others do not. For instance, Arkansas and Florida regulate cooperative utilities to a greater extent; other states have exempted their municipal and cooperative utilities from administrative regulation. It will be a state-by-state determination of the institutions which are authorized to regulate a given EGU or distribution utility.

authority. Therefore, states will likely need to pass legislation to enforce carbon reductions set forth in a SIP. This is not to say that all states will necessarily need legislation, but in particular to take advantage of the portfolio approaches detailed by EPA, a new institutional arrangement between PUCs and state environmental regulators will be necessary. By the same token, even for states adopting a source-based approach, the environmental regulator will likely need to coordinate with the PUCs to fully appreciate cost and reliability concerns.

Enacting legislation to create the new institutional arrangements may be difficult in vertically-integrated states. Generation & Transmission (G&T) organizations, rural electric cooperatives, and municipalities have traditionally been opposed to ceding generation planning to an outside regulatory agency (assuming, *arguendo*, that the outside agency has jurisdiction over these entities in the first instance). Municipal and public power utilities have always self-determined their resource plans. While G&Ts are required in some states to obtain approval to construct a new generation plant, they have not been required to obtain approval of their IRPs. In addition, the rivalrous nature of different utilities' interests threatens 'who's ox is being gored' rivalries, where the costs and pains will be difficult to apportion among utilities with dramatically different carbon profiles.

d. What if a State Declines to Participate?

A final option states might consider with carbon rule implementation would involve the affirmative refusal to participate in devising a SIP. This could occur through the failure of legislation creating the institutional administrative structure described earlier. Or, it could be conceived as an affirmative policy stance of the state to not submit a SIP.¹⁶

While a state may chart such a course, the outcome would be EPA implementing its own Federal Implementation Plan (FIP) and enforcement authority under the Clean Air Act. The FIP would, in essence, amount to EPA taking over resource planning in the given state and subsuming enforcement powers for

¹⁶ There are cooperative federalism schemes in the utility sphere where states have opted-out. Alaska and Hawaii, for instance, have not passed statutes to participate in the federal PHMSA program. Virginia, quite notably, refused to participate in implementation of the Telecommunications Act of 1996.

carbon reductions to itself. Furthermore, EPA would take jurisdiction over where carbon reductions come from and what makes up an adequate portfolio of reductions — the 'right' combination of heat rate improvements, increased CT dispatch, and renewable and demand response. In short, a state would be handing over its Section 111(d) prerogatives to the federal agency, which has little to no experience with issues such as reliability, cost analysis or demand response verification. Thus, while defiance of EPA is certainly an option, the potential downside of such an approach could be precipitous for states electing such a path.¹⁷

IV. CO₂ SIP Implementation in Vertically Integrated States

a. General Resource Planning Issues

In vertically-integrated states, modern IRPs look at issues that go well beyond a utility's self-build generation plans. Investor-owned utilities present estimates to state public utility commissions for future load, customer growth, fuel (gas and coal) prices, cost of renewables, resource margins, and other data to support proposed IRPs. In addition to any self-build proposals, these plans involve power purchases from independent power producers (IPPs), renewable energy portfolios, and DSM. Typically, state policy goals or mandates such as renewable energy penetration and DSM are overlaid onto a lowest cost portfolio approach.

While G&Ts, rural electric cooperatives, and municipalities have been subject to environmental regulation at the federal and state levels, including air quality regulation under the Clean Air Act, EPA's proposed CO₂ Emission Guidelines go beyond pollution control measures directed at EGUs. Perhaps recognizing that inside-the-fence, *i.e.*, implemented at the source, measures are insufficient to meet EPA's 30 percent carbon reduction goal by 2030, only one building block assumption - average heat rate improvement of six percent for coal-fired EGUs - is source-focused. Building blocks 2, 3 and 4 of the CO₂ Emission Guidelines assume that utilities can meet

¹⁷ EPA enforcement is not limited to imposition of a FIP. Under certain circumstances, EPA may (1) prohibit the approval by the U.S. Secretary of Transportation of state highway funding for the state or (2) increase the non-attainment area New Source Review emission offset ratio to at least two to one. 42 U.S.C. §§ 7509(a)(3), 7509(b).

certain outside-the-fence metrics. Although the proposed rule does not require states and utilities to actually implement these metrics, they are the root of each CO₂ performance goal.

b. State PUC or Environmental Regulator as Lead Agency

Portfolio-based metrics, *i.e.*, non-source-based emission limits, strongly resemble the resource planning function traditionally performed by state utility commissions: reliance on existing and under-construction natural gas CC units to up to 70 percent capacity factor; expansion of renewable generation; reliance on existing and under-construction nuclear facilities; and increase of demand-side energy efficiency to one and one-half percent annually. A state may choose to enforce the measures utilized by the EPA to determine carbon reduction amounts for the state. In the alternative, if these prove impracticable or unworkable, a state may order a variant of these measures or simply mandate closure of carbon-emitting EGUs.

In any case, entities that own or dispatch EGUs - and that have not been subject to state authority - will inevitably find themselves under the umbrella of state CO₂ regulations by a designated agency. That agency could be the state PUC, or the state environmental agency, or some new hybrid of the two agencies.

With a portfolio compliance approach in particular, the state PUC makes the most sense based on its experience and expertise with Building Blocks 2, 3 and 4.¹⁸ State environmental agencies may be given a consulting role similar to the process employed in the Clean Air-Clean Jobs Act in Colorado,¹⁹ but the state

¹⁸ It could be argued that state environmental agencies should be given the authority to develop and impose carbon reductions on EGUs, as these agencies have traditionally been involved with implementation of EPA pollution reduction measures. However, given the IRP-like "building block" approach of EPA in its proposed rule, it appears more appropriate for state PUCs to have primary authority. Nevertheless, one of the political disputes that may develop is over which agency should be tasked with this important role.

¹⁹ See Colorado PUC Docket No. 10M-245E; Colorado House Bill 10-1365.

PUC is much more likely to adjudicate the resource plan. In the alternative, with a pure source-based compliance plan, the environmental agency might be adequately suited to take the lead. However, the PUC would still need to be involved because the state will also have cost and system reliability concerns. In either case, states will be wrestling to create a new hybrid regulatory process that likely involves both the PUC and the environmental regulator.²⁰

The state agency devising the Carbon IRP also will have to take on the role as CO₂ SIP enforcer. Normally,

Portfolio-based metrics, *i.e.*, non-source-based emission limits, strongly resemble the resource planning function traditionally performed by state utility commissions.

utilities present a resource plan to the state commission, and the commission may approve, deny or modify the plan. A utility gains a presumption of prudence by following the measures in the approved plan. A state agency enforcing the EPA Section 111(d) rule must be able to enforce "measures that reduce EGU CO₂ emissions" and implement "corrective actions, if necessary."²¹ This changes the consequences of a "missed" IRP decision: the state must be able to

enforce the Carbon IRP, presumably by dictating and sanctioning all relevant EGUs or other participants in the carbon reduction portfolio under the state SIP. The corrective actions available to the state Carbon IRP-enforcer include those sanctions available under Section 113(a)-(f) of the Clean Air Act, including without limitation the issuance of administrative penalties of up to \$37,500 per day²² and instituting criminal proceedings against "[a]ny person who knowingly" violates relevant provisions of a SIP.²³ The "any person" language in the Clean Air Act can and does allow for enforcement against private parties.

²⁰ Tennessee and Nebraska, because they are exclusively served through public power, might either consider implementing the rule exclusively through the environmental regulator - a tall order if they are going to pursue a portfolio approach, especially involving the audit and verification burdens associated with DR. Alternatively, they could decide to confer the Nebraska PSC and the Tennessee Regulatory Authority (TRA), respectively, with new jurisdiction over the carbon IRP that they do not currently possess.

²¹ CO₂ Emission Guidelines at 46.

²² 42 U.S.C. § 7413(d). In late 2013, EPA made the default penalty up to \$37,500 per day of violation. 78 Fed. Reg. 66,643 (Nov. 6, 2013).

²³ 42 U.S.C. § 7413(c).

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c. Timing Issues with State Enabling Legislation

The need for state legislation in vertically integrated states creates a significant timing issue. The proposed CO₂ Emission Guidelines will not be finalized until June 2015 under EPA's current timeline, and (absent an EPA-granted extension of time) states must submit SIPs by June 2016. Most state legislative sessions are conducted in the early months of the calendar year, e.g., January to April or May. In addition, some state legislatures do not meet every year. For example, the state legislative sessions of Montana, Nevada, North Dakota and Texas occur biennially, in odd-numbered years.

Many states may be reluctant to pass legislation granting CO₂ reduction enforcement authority to state PUCs or other agencies until the EPA rule is final. EPA has made clear that it is engaged in a "listening tour" to receive comments from the states and other stakeholders, and that it may change the proposed rule based on this feedback. Indeed, EPA's proposed rule poses numerous questions about whether certain provisions should be imposed, introducing a degree of uncertainty regarding the potential scope of the final rule.

Those states that wait until 2016 to pass legislation may find themselves in an unenviable position due to impossible time constraints (notably, Montana, Nevada, North Dakota and Texas will not have a 2016 legislative session unless a special session is called). Resource planning cases require substantial planning and development by utilities before they are filed. These cases are quasi-adjudicatory, involving interventions from various stakeholders, testimony, discovery, motions practice, briefing, and evidentiary hearings. This time crunch could become even more severe considering that many utilities, e.g., non-jurisdictional municipal utilities and cooperatives, have never filed an integrated resource plan before, and

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The proposed CO₂ Emission Guidelines do include a one- or two-year extension provision that involves a two-phased SIP submittal process for state plans. If a state needs additional time to submit a complete plan, then it must tender an initial plan by June 30, 2016 that explains why the state needs more time and includes commitments to ensure that the state will submit a complete plan by June 30, 2017 or 2018, as appropriate.²⁵ To be approvable, the initial plan must include specific components, including a description of the plan approach, initial quantification of the level of emission performance that will be achieved in the plan, a commitment to maintain existing measures that limit CO₂ emissions, an explanation of the path to completion, and a summary of the state's response to any significant public comment on the approvability of the initial plan. If the initial plan is approved, the state would have until June 30, 2017 to submit a complete plan if the geographic scope of the plan is limited to that state. If the state develops a plan using multi-state approach, it would have until June 30, 2018 to submit a complete plan.

²⁴ Any planning process necessarily involves the input of appropriate regulatory bodies at the state level as well as affected entities. This may require PUCs to open investigatory/miscellaneous dockets or their functional equivalent under state law to allow utilities and other affected entities to submit relevant data and preserve confidentiality protections, where necessary. Some utilities are already receiving informal "discovery requests" regarding CO₂ emissions data and other relevant information. To allow utilities to protect this information, PUCs should open investigatory/ miscellaneous dockets or a functional equivalent such that there is a level of administrative law formality to allow affected entities to protect confidential and proprietary information. In addition, affected entities, specifically jurisdictional and non-jurisdictional utilities as well as fuel supply, should be engaging with state regulators and pushing to begin the exploration of the structure of a Carbon IRP or similar process what legislative changes may be required.

²⁵ See, e.g., 40 C.F.R. §§ 60.5755, 5760 (as proposed in the CO₂ Emission Guidelines at 618).

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However, it is unclear whether the EPA would allow a one- or two-year delay for a state that has not both passed legislation effective before June 30, 2016 and have a state agency-determined initial plan approach with "quantification of the level of emission performance that will be achieved in the plan."²⁶ The language of the CO₂ Emission Guidelines appears to require a demonstration that the plan will meet the required carbon reductions and be enforceable, suggesting that the legislation and state agency determination must be complete for any initial plan and related extension of time to submit a complete plan to be approved.

V. CO₂ SIP Implementation in Restructured States

a. Background on Restructured States and References in the CO₂ Emission Guidelines

In restructured states, the wholesale market clears generation needs, and utilities either have spun-off their generation assets, or hold them in a separate subsidiary. Electric distribution utilities purchase electricity from competitive wholesale markets. There is no IRP process in these states, and therefore EPA takes the position that "[a] state-driven portfolio approach" is likely most suitable for restructured states. EPA envisions a regime where a wide variety of entities, ranging from generation owners to non-profit organizations, would be subject to an overarching regulatory scheme to achieve standards and CO₂ emission reductions set forth in the SIP. EPA provides an example for restructured states:

One likely state plan scenario involves inclusion of enforceable obligations for state-regulated entities other than affected EGUs. An example of a state-regulated entity that is not an owner or operator of affected EGUs may be an electric distribution utility. These entities are typically regulated by a state public utility commission. An example of an enforceable state plan measure that might apply to an electric distribution utility is a compliance obligation under a state end-use energy efficiency resource standard (EERS) or renewable portfolio standard (RPS), or implementation of incentive programs for

the deployment of end-use energy efficiency and renewable energy technologies.²⁷

b. Practical Issues in Restructured States

This creates numerous practical issues. Perhaps the paramount issue is that the regime outlined by EPA may ultimately result in a degree of soft reintegration of the utility function in restructured states. These states opted for competitive generation as a means to lower costs and achieve optimal resource mixes through competition instead of centralized resource planning by state utility commissions or similar entities. An equivalent Carbon IRP process necessarily reintroduces a central planning aspect to generation because allowable facilities must now be approved through the regulatory process and portfolios must be balanced by each state.

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There are other practical considerations in restructured states. First, as with vertically integrated states, regulation of such a diverse group of entities will almost certainly require new enabling legislation. This introduces all of the same timing considerations discussed above. It also creates overlapping regulator issues between state utility commissions and environmental regulators, as regulation of certain activities, *e.g.*, non-profits administering or implementing energy efficiency programs, may be done by one agency while merchant generators may be regulated separately by another agency. In turn, this creates implementation difficulties for any SIP approved by EPA.

Finally, submission of a SIP premised upon a new regulatory scheme raises general compliance issues. SIPs must be enforceable by the states to be approved by EPA. If a state submits a SIP which it cannot enforce because it cannot convey legal authority and get itself organized, it opens itself up to a FIP and numerous other potential sanctions by EPA. The FIP

²⁶ CO₂ Emission Guidelines, at 48.

²⁷ State Plan Considerations at 14.

would create a host of legal issues, from potentially forcing state officials to enforce obligations they do not have authority to enforce under state law to EPA indirectly engaging in resource planning and directing system dispatch. Another concern in restructured states is that states would pass new legislation implementing a new regulatory paradigm to allow for enforcement against the relevant entities and actors. Once this avenue is created under state law, it creates an opportunity for EPA to come in and regulate these entities indirectly through the FIP under the new state laws. Indeed, the creation of new regulatory paradigms creates a similar issue in vertically-integrated states as well.

Another concern in restructured states is that states would pass new legislation implementing a new regulatory paradigm to allow for enforcement against the relevant entities and actors. Once this avenue is created under state law, it creates an opportunity for EPA to come in.

Restructured markets thus present a challenge to the state-by-state Carbon IRP model that seems to be contemplated by the EPA rule. To be sure, the most sensible course would appear to be for restructured states to engage in multi-state plans coincident with RTO boundaries. This creates its own problems, particularly in states like Missouri, Illinois, Indiana and Arkansas, where two separate RTOs operate within the state. Nevertheless, we turn to the institutional issues associated with multi-state plans below.

c. Environmental Dispatch as a Compliance Strategy

Environmental dispatch protocols have been referenced in the days following the issuance of the CO₂ Emission Guidelines as potential multi-state compliance strategies in states that participate in restructured wholesale markets. With environmental dispatch, speaking strictly in the CO₂ context, the RTO seeks to identify an optimal generation schedule that

achieves appropriate power balance, satisfies unit operating limits, and minimizes both fuel cost and CO₂ emissions. Based upon our rudimentary understanding of environmental dispatch protocols, the use of a carbon imputation in bid pricing represents a clear way to implement an environmental dispatch strategy. However, the CO₂ Emission Guidelines do not appear to provide for such a compliance strategy in a SIP. In

It is unclear how a SIP, or a multi-state SIP for that matter, would be built around a dispatch protocol for an RTO. This also raises questions of enforcement.

addition, it is unclear how a SIP, or a multi-state SIP for that matter, would be built around a dispatch protocol for an RTO. This would be novel to say the least, and also raises questions of enforcement, specifically whether the member states could enforce the dispatch protocols through the SIP and how corrective action might work in this context. Both enforcement and corrective action are mandated within EPA's SIP approval criteria.²⁸ While significant questions remain, EPA seeks comment on the roles of RTOs in implementing SIPs: "The ISO/RTO Council, an organization of electric grid operators, has suggested that ISOs and RTOs could play a facilitative role in developing and implementing region-wide, multi-state plans, or coordinated individual state plans. Existing ISOs and RTOs could provide a structure for achieving efficiencies by coordinating the state plan approaches applied throughout a grid region."²⁹ Needless to say, the roles of RTOs and environmental dispatch in effectuating CO₂ Emission Guidelines are an open question in this rulemaking.

The SIP modification process, as proposed, raises questions how a SIP premised on an "environmental dispatch" strategy would be modified if it were not achieving the intended results. When implementing an approved SIP, a state might find the need to update or alter one or more of the enforceable measures in the state plan, or even replace certain existing measures with new measures. The CO₂ Emission Guidelines provide:

²⁸ CO₂ Emission Guidelines at 46.

²⁹ *Id.* at 430.

EPA proposes that the state may revise its state plan provided that the revision does not result in reducing the required emission performance for affected EGUs specified in the original approved plan. In other words, no "backsliding" on overall plan emission performance through a plan modification would be allowed.

If the state wishes to revise enforceable measures in its approved state plan, EPA proposes that the state must submit the revised enforceable measures to the EPA and demonstrate that the revised set of enforceable measures in the modified plan will result in emission performance at affected EGUs that is equivalent to or better than the level of emission performance required by the original state plan.³⁰

Accordingly, a SIP premised on environmental dispatch of generation would appear to require EPA approval before any material changes to dispatch protocol were made. EPA thus would become the approval authority for generation dispatch protocols under a mass emissions plan.³¹

VI. Multi-State State SIP Considerations

a. EPA's Proposed Multi-State SIPs

In the proposed CO₂ Emission Guidelines, EPA proposes a multi-state SIP compliance avenue, *i.e.*, two or more states can jointly submit a SIP with aggregated emission goals. EPA has implemented past air quality programs, such as the NO_x Budget Trading Program, on a regional basis; however, the notion that states can

³⁰ *Id.* at 468-69.

³¹ "[A]ny person," including PUCs, would also likely be subject to novel Clean Air Act citizen suits during the pendency of its request to modify dispatch protocols. 42 U.S.C. § 7604. Certain special interest groups bring these suits with regularity.

The notion that states can jointly submit a SIP, and in turn rely on one another to effectuate compliance with an emission standard, is novel under the Clean Air Act.

jointly submit a SIP, and in turn rely on one another to effectuate compliance with an emission standard, is novel under the Clean Air Act.³² EPA describes multi-state SIPs as follows:

For states wishing to participate in a multi-state plan, the EPA is proposing that only one multi-state plan would be submitted on behalf of all participating states. The joint submittal would be signed by authorized officials for each of the states participating in the multi-state plan and would have the same legal effect as an individual submittal for each participating state. The joint submittal would adequately address plan components that apply jointly for all participating states and for each individual state in the multi-state plan, including necessary state legal authority to implement the plan, such as state regulations and statutes. Because the multi-state plan functions as a single plan, each of the required plan components ... would be designed and implemented by the participating states on a multi-state basis.³³

States retain primacy under Section 111(d) to develop legally enforceable emission standards and compliance schedules, but states submitting a multi-state SIP would have a multi-state rather than single state CO₂ performance goal and would demonstrate emission performance "in aggregate with partner states,"

States retain primacy under Section 111(d) to develop legally enforceable emission standards and compliance schedules, but states submitting a multi-state SIP would have a multi-state rather than single state CO₂ performance goal and would demonstrate emission performance "in

³² See, e.g., EPA, *Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2)*, at 1 (Sept. 13, 2013) (providing in part that "Under Clean Air Act (CAA) sections 110(a)(1) and 110(a)(2), each state is required to submit a state implementation plan (SIP) that provides for the implementation, maintenance, and enforcement of each primary or secondary national ambient air quality standard (NAAQS). Moreover, section 110(a)(1) and section 110(a)(2) require each state to make this new SIP submission within 3 years after promulgation of a new or revised NAAQS.") (emphasis added).

³³ CO₂ Emission Guidelines at 434.

aggregate with partner states.³⁴ This aggregation occurs notwithstanding whether states pursue a rate-based or mass-based compliance approach:

[S]tates taking a rate-based approach would demonstrate that all affected EGUs subject to the multi-state plan achieve a weighted average CO₂ emission rate that is consistent, in aggregate, with an aggregation of the state-specific rate-based CO₂ emission performance goals established in the emission guidelines that apply to each of the participating states. If states were taking a mass-based approach, participating states would demonstrate that all affected EGUs subject to the multi-state plan emit a total tonnage of CO₂ emissions consistent with a translated multi-state mass-based goal. This multi-state mass-based goal would be based on translation of an aggregation of the state-specific rate-based CO₂ emission performance goals established in the emission guidelines that apply to each of the participating states.³⁵

Accordingly, regardless of the emission calculation approach chosen, multi-state SIPs are submitted jointly and based upon aggregated performance goals. States would “rise and fall” together based on collective performance and compliance with the multi-state SIP.

EPA also may include state-specific requirements for multi-state plans. The proposed rule asks whether states submitting multi-state plans should also be required to provide individual submittals that: (1) provide state-specific elements of the multi-state plan; and (2) address all elements of the multi-state plan.

b. RGGI as the Prototypical Multi-State SIP

The CO₂ Emission Guidelines reference the Regional Greenhouse Gas Initiative (RGGI) on numerous occasions as an example of a regime that addresses CO₂ emissions on a multi-state, regional basis, and EPA cites RGGI as an example of a group of states that may submit a multi-state SIP.³⁶ Given

EPA’s understandable emphasis on enforceability, however, it is questionable whether RGGI as currently structured could submit a SIP that would satisfy EPA’s four general criteria.

RGGI is a cap-and-trade system for CO₂ emissions from fossil-fuel fired EGUs with 25 MW or greater generating capacity. The following nine states currently participate: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. This regional CO₂ emissions reduction strategy began in 2005, when seven states signed a Memorandum of Understanding (MOU) committing the state to the “CO₂ Budget Trading Program.” The MOU set an initial regional emission cap of 121.2 million short tons; this regional base annual CO₂ emissions budget was then apportioned to each state individually based on its specific emissions history. EPA explains that:

The program works as a coordinated regional whole through a shared emission and allowance tracking system and allowance auction process, but is implemented in accordance with materially consistent, stand-alone state regulations and individual statutory authority. These regulations recognize CO₂ allowances issued by other participating states for use by affected EGUs when complying with each state’s emission limitation, but contain all the necessary components to administer the program requirements on an individual state basis.³⁷

As a result, each state develops its own individual regulatory and/or statutory structure based on an agreed-upon “Model Rule” that provides a framework for the development of individual state proposals.

mass-based plan that demonstrates emission performance by affected EGUs on a multi-state basis. Additional states may also choose to join a multi-state plan. The mechanics of translating rate-based goals into mass-based goals and considerations related to multi-state plans are discussed below in Section VIII on state plans.”

³⁷ *State Plan Considerations* at 18 (further providing that “[t]he emission limitation consists of a requirement to submit CO₂ allowances equal to reported CO₂ emissions during a compliance period. While states have individual emission budgets, representing the total number of allowances issued for a given year that are available for allocation, there are no individual state emission limits. The CO₂ emission constraint is regional, based on the sum of state CO₂ emission budgets.”)

³⁴ *Id.* at 116, 438.

³⁵ *Id.* at 438.

³⁶ *Id.* at 360 (“[T]he EPA’s approach allows states to submit multi-state plans. The EPA expects this flexibility to reduce the cost of achieving the state goals and therefore expects it to be attractive to states. For example, the RGGI-participating states could choose to submit a multi-state

While this CO₂ budget trading program is enforceable at the state level, EPA admits that “enforceability would be contingent, in part, on states having comparable enforcement mechanisms.”

Importantly, each member state, with one exception resulting in multi-year litigation, passed *new legislation* to implement the Model Rule in their respective states and facilitate participation in RGGI.³⁸ The Model Rule does not supplant state-developed rules, but rather, provides a general organizational structure for states to follow when implementing their own provisions. While this CO₂ budget trading program is enforceable at the state level, EPA admits that “enforceability would be contingent, in part, on states having comparable enforcement mechanisms.”³⁹

A regional organization (RO) facilitates the ongoing administration of RGGI. The RO (RGGI, Inc.) is a non-profit entity incorporated in Delaware that was created in 2007 to provide technical and administrative support to the member states.⁴⁰ It operates pursuant to by-laws agreed upon by the member states.⁴¹ The RO is managed by its Board of Directors, which consists of two directors from each member state, (1) the chair of the state’s energy

regulatory agency, and (2) the chief executive of the state’s environmental regulatory agency, unless the Governor determines that other state officials should act as the state’s directors.⁴²

c. RGGI Administration and Enforcement

While each participating state is responsible for its own regulatory program, the RO serves as a “forum for collective deliberation and action” and provides technical assistance in implementing certain components of the program, such as auctions, offsets, emissions tracking, and market monitoring.⁴³ To be sure, Article XII of the RO’s By-Laws explains that the RO is a technical assistance organization only, and “shall have no regulatory or enforcement authority with respect to any existing or future program of any

This calls into question EPA’s ability to find that a multi-state SIP premised upon a RGGI-like structure, *i.e.*, a regional entity with mere “technical assistance” authority and a consortium of state laws implemented and enforced at the state level, could be approved under EPA’s “general criteria” for SIP evaluation as set forth in the CO₂ Emission Guidelines.

Signatory State, and all such sovereign authority is reserved to each Signatory State.”⁴⁴ In sum, with the technical assistance of the RO, each member state essentially adopts the Model Rule into its preexisting regulatory framework through new state legislation. Importantly, however, the Model Rule, as well as state legislation implementing the Model Rule as modified to a member state’s satisfaction, is not enforceable as between the states because the structure lacks an interstate enforcement mechanism and state laws by their very nature cannot result in extraterritorial enforcement.

This calls into question EPA’s ability to find that a multi-state SIP premised upon a RGGI-like structure, *i.e.*, a regional entity with mere “technical assistance” authority and a consortium of state laws implemented and enforced at the state level, could be approved under EPA’s “general criteria” for SIP evaluation as set forth

³⁸ See Connecticut (R.C.S.A. 22a-174-31; Conn. Gen. Stat. Section 22a-200c); Delaware (7 DE Admin Code 1147; Title 7 Chapter 60 of the Delaware Code, Subchapter IIA, §6043); Maine (DEP Chapter 156-158; Maine Rev. Stat., Title 38, Chapter 3-B); Maryland (Department of Environment, Title 26, Subtitle 9; Environment Article, §§1-101, 1-404, 2-103, and 2-1002(g), Annotated Code of Maryland); Massachusetts (DEP Regulations 310 CMR 7.70; 225 CMR 13.00; M.G.L. c. 21A, §22); New Hampshire (NH Code of Admin. Rules, Chapter Env-A 4600; Chapter Env-A 4700; Chapter Env-A 4800; RSA 125-O:19-28; RSA 125-O:8, I(c)-(g)); Rhode Island (Dept. of Environmental Management Office of Air Resources, Air Pollution Control Regulation No. 46 and 47; R.I. Gen. Laws §42-17.1-2(19), §23-23 and §23-82); Vermont (30 V.S.A. § 255; 30 V.S.A. § 209(d)(3); Agency of Natural Resources, Vermont CO₂ Budget Trading Program 23-101 – 23-1007). New York did not pass legislation, which resulted in subsequent litigation. However, the court did not consider the merits of the claims because they were time-barred. See *Thrun v. Cuomo*, 112 A.D.3d 1038 (N.Y. App. Div. Dec. 5, 2013).

³⁹ *State Plan Considerations* at n.19.

⁴⁰ 2007 RGGI By-Laws, at Art. I, available at http://www.rggi.org/old/docs/rggi_bylaws_12_12_07.pdf.

⁴¹ 2007 RGGI By-Laws, at Art. I.

⁴² RGGI By-Laws, at Art. IV, § 1.

⁴³ RGGI By-Laws, at Art. I.

⁴⁴ RGGI By-Laws, at Art. XII.

in the CO₂ Emission Guidelines. States would not be able to enforce the terms of the joint, multi-state SIP *vis-à-vis* one another under a RGGI-like structure. This would likely render the SIP unenforceable, and thus not approvable by EPA, absent an interstate enforcement mechanism.

d. Member State Rivalries and the Practical Need for Enforcement Authority

From a practical standpoint, member states themselves may want interstate enforcement authority to ensure that all member states fulfill their obligations under a multi-state SIP. Member state interests could become rivalrous if and when a state does not fulfill its SIP obligations or through issues involving interstate capacity needs.⁴⁵ For instance, in many cases around the nation, electric capacity serving demand in one state comes from another state. A multi-state program makes sense to ensure that a given state's parochial carbon interests do not negatively affect another state's capacity needs.

Under any rivalrous scenario, states would want the ability to enforce the multi-state SIP provisions against the offending member state. While it is valid to point out that state rivalry has not been an issue in RGGI, there is no interstate enforcement provision in the RGGI structure. Moreover, and equally as important, the RGGI cap of allowed emissions from regulated power plants was 165 million tons in 2013, but actual 2012 emissions were only 91 million tons. Emissions were lower than previously anticipated due to low

⁴⁵ For example, the Missouri Joint Municipal Electric Utility Commission (MJMEUC) is authorized by Missouri state law to operate as an electric utility for the benefit of the combined requirements of its members. MJMEUC has ownership interests in coal-fired generation units in Missouri, Arkansas, Illinois and Nebraska. Accordingly, MJMEUC customers are dependent upon out-of-state generation to meet its capacity needs. If one of these states decides to retire coal-fired generation to meet its single state or multi-state SIP obligations such that reliability and/or affordability is affected, one can easily foresee a rivalrous scenario. This interstate capacity issue exists in the western U.S. as well – the North Valmy Generating Station in Nevada serves Idaho customers (in addition to in-state customers), the Navajo Generating Station in Arizona serves customers in California and Nevada (as well as Arizona), and the Jim Bridger Power Plant in Wyoming serves customers in Idaho and Utah. These provide just a few examples of the widespread interstate capacity issues across the country necessarily implicated by the CO₂ Emission Guidelines.

natural gas prices, energy conservation measures, and the struggling economy. Accordingly, with a cap that high, no member state was in severe danger of noncompliance; it is these potential noncompliance scenarios that would lead to an action by one state against another state. In February 2013, the RGGI cap was lowered to 91 million tons for 2014 with 2.5% annual reductions until 2020. Accordingly, the future may hold more rivalrous member state relationships in RGGI with a more restrictive cap.

e. Enter the Interstate Compact

The U.S. Constitution expressly addresses what amounts to contracts between individual states. Article I, section 10, clause 3 of the U.S. Constitution provides that “[n]o State shall, without the consent of Congress ... enter into any Agreement or Compact with another State.” Interstate compacts can create enforceable obligations between parties, and the U.S. Supreme Court has held for nearly 200 years that compacts are contracts between individual states.⁴⁶

Courts have discussed “some of the indicia of compacts,” specifically “establishment of a joint organization for regulatory purposes; conditional consent by member states in which each state is not free to modify or repeal its participation unilaterally; and state enactments which require reciprocal action for their effectiveness.”⁴⁷ Whether Congressional approval of an interstate compact is required, however, depends upon the nature of the agreement:

To form a compact, two or more states typically negotiate an agreement, and then each state legislature enacts a law that is identical to the agreement reached. Once all states specified in the compact have enacted such laws, the compact is formed. In some cases, if a compact affects the balance of power between the states and the federal government or affects a power constitutionally delegated to the federal government, it must also obtain congressional consent. In consenting to a compact, Congress may add certain conditions⁴⁸

⁴⁶ *Green v. Biddle*, 21 U.S. (8 Wheat.) 1, 92 (1823).

⁴⁷ *Seattle Master Builders Ass'n v. Pacific Northeast Electric Power & Conservation Planning Council*, 786 F.2d 1359, 1363 (9th Cir. 1986).

⁴⁸ U.S. Government Accountability Office, *INTERSTATE COMPACTS: An Overview of the Structure and Governance*

For example, a 2007 Government Administrative Office (GAO) study identified 76 environmental and natural resources interstate compacts, and 59 required Congressional approval.⁴⁹ The U.S. Supreme Court has wrestled with the line of where Congressional approval of interstate compacts is needed and where it is not several times. In 1893, the Supreme Court held:

Looking at the clause in which the terms "compact" or "agreement" appear, it is evident that the prohibition is directed to the formation of any combination tending to the increase of political power in the states, which may encroach upon or interfere with the just supremacy of the United States.⁵⁰

Therefore, the Compact Clause applies to agreements directed to the formation of any unit that may increase states' political power encroaching on federal power.⁵¹ Congressional consent is not required for joint state activity not affecting federal authority.⁵²

According to the analysis developed by the Supreme Court, a court first evaluates whether the agreement or arrangement at issue constitutes a compact. The key component of this analysis involves looking at the "indicia" set forth by the Ninth Circuit in *Seattle Master Builders Association*. If a compact is in fact at issue, courts evaluate if the compact encroaches upon federal power, *i.e.*, whether it is "political."⁵³ A compact is "political" if it (1) impacts the federal structure or (2) effects the interests of non-compacting sister states.⁵³ As to the first inquiry, in the words of the Supreme Court, "[t]he relevant inquiry must be one of impact on our federal structure."⁵⁴ Courts also consider whether

The multi-state enforcement issues with RGGI lead to the conclusion that a contract, in the form of an interstate compact, would be necessary to implement an enforceable multi-state SIP.

the compact affects the interests of non-compacting sister states. Under either scenario, *i.e.*, impact on federal structure or effects on the interest of non-compacting sister states, Congressional approval is required for the compact.⁵⁵

f. Multi-State SIPs and the Compact Clause

The multi-state enforcement issues with RGGI lead to the conclusion that a contract, in the form of an interstate compact, would be necessary to implement an enforceable multi-state SIP that would allow states to enforce rights against one another to achieve compliance with the multi-state performance goal.

Any such agreement would facially have all indicia of a compact: (1) a joint organization formed for regulatory purposes to effectuate compliance with the CO₂ Emission Guidelines; (2) conditional consent by each member state to have no right to modify or repeal its participation unilaterally as this consent would be required to submit an approvable multi-state SIP; and (3) state enactments requiring reciprocal action, as each member state would pass new legislation to allow for participation in the multi-state SIP and achievement of the multi-state performance goal would turn on each member state satisfying its obligations under the multi-state SIP. In fact, while some commentators have questioned whether RGGI was an interstate compact,⁵⁶ an agreement to implement multi-state SIPs would even more directly satisfy the *Seattle Master Builders*

of Environment and Natural Resource Compacts, at 1 (Apr. 2007), available at <http://www.gao.gov/assets/260/258939.pdf>.

⁴⁹ *Id.*

⁵⁰ *Virginia v. Tennessee*, 148 U.S. 503, 519 (1893).

⁵¹ *Northeast Bancorp, Inc. v. Board of Governors of Federal Reserve System*, 472 U.S. 159 (1985).

⁵² *Seattle Master Builders Ass'n v. Pacific Northwest Elec. Power and Conservation Planning Council*, 786 F.2d 1359 (9th Cir. 1986).

⁵³ *U. S. Steel Corp. v. Multistate Tax Comm'n*, 434 U.S. 452, 477 (1978).

⁵⁴ *Id.* at 471.

⁵⁵ *Id.* at 477. In both *U.S. Steel* and *Northeast Bancorp*, the Supreme Court applied a sister state interest analysis, suggesting that the sister state interest doctrine is in force despite being rejected as a justification for overturning the compacts in those particular cases.

⁵⁶ See, e.g., Edison Electric Institute, *Comments to Regional Greenhouse Gas Initiative Memorandum of Understanding*, at 22-24 (Mar. 20, 2006), available at http://www.rggi.org/docs/rggi-ecimou_comments032006final.pdf. In addition, the New York state lawsuit regarding the lack of legislation also challenged RGGI in part on grounds that it violated the Compact Clause. However, this case was dismissed without considering the merits by the New York Supreme Court because the all claims were either time-barred or moot. See *Thrun v. Cuomo*, 112 A.D.3d 1038 (N.Y. App. Div. Dec. 5, 2013).

Association factors because states likely could not unilaterally withdraw as they can under RGGI. If member states could unilaterally withdraw, it would raise questions as to whether the multi-state SIP was enforceable between member states and could satisfy EPA's general criteria.

Assuming an agreement or multi-state SIP is in fact a compact, the next question is whether the compact is "political." As to federal structure, a multi-state SIP would appear to impact the federal structure given that the Clean Air Act is a federal statute and the CO₂ Emission Guidelines are promulgated by EPA pursuant to Section 111(d) and its federal implementing regulations. Indeed, a counterargument exists that the Clean Air Act, through its purported embrace of cooperative federalism, actually involves states implementing state-specific programs through SIPs. In other words, it is technically a federal program but there is no federal structure because the states implement and enforce the requirements. However, the former argument would appear to be stronger and, at the very least, would potentially subject a multi-state SIP that did not receive Congressional approval for litigation. Moreover, there is also an argument that a multi-state SIP would interfere with federal authority by potentially affecting the grid reliability.

Second, notwithstanding the analysis above regarding impact on the federal structure, it would almost certainly appear that any interstate compact would require Congressional approval on the basis of effects upon non-compacting sister states. As EPA notes in the CO₂ Emission Guidelines, "[t]he utility power sector is unique in that, unlike other sectors where the sources operate independently and on a local scale, power sources operate in a complex, interconnected grid system that typically is regional in scale."⁵⁷ Accordingly, if a subset of states in an interconnected regional grid system entered into a multi-state SIP and associated interstate compact, it would likely affect the interests of the non-compacting states in that region. While the Supreme Court has

never rejected an interstate compact on the basis of effects on sister state interests, the multi-state SIP avenue raises a constitutional issue that has not been visited by the Supreme Court for many years.

Accordingly, it provides an interesting academic question at a minimum and a likely litigation path for any party seeking to challenge the validity of a multi-state SIP.

g. Congressional Approval and Timing Issues

The potential need for Congressional approval injects additional political and timing elements into any multi-state SIP process. Indeed, political issues are beyond the scope of this paper but could certainly inject delay into the approval process, as Congressional approval for an interstate compact would likely need to precede EPA approval of any multi-state SIP tied to the interstate compact. In its report, the GAO discusses the process for Congressional approval:

Congress generally gives its consent in one of three ways: (1) after the fact, by passing legislation that specifically recognizes and consents to the compact as enacted by the states; (2) in advance, by passing legislation encouraging states to enter into a specified compact or compacts for specified purposes; or (3) implied after the fact, when actions by the states and the federal government indicate that Congress has granted its consent even in the absence of a specific legislative act. In addition, Congress may impose conditions as part of granting its consent, and it typically reserves the right to alter, amend, or repeal its consent. Any proposed amendment to a compact must follow the compact approval process, unless the compact specifies otherwise.⁵⁸

Advance approval is irrelevant with regard to Section 111(d) and the CO₂ Emission Guidelines. An example of a statute providing advance Congressional approval of an interstate compact is the Energy Policy Act of 2005, which provided advance Congressional approval

It would almost certainly appear that any interstate compact would require Congressional approval on the basis of effects upon non-compacting sister states.

The potential need for Congressional approval injects additional political and timing elements into any multi-state SIP process.

⁵⁷ CO₂ Emission Guidelines, at 72.

⁵⁸ *Interstate Compacts GAO Report* at 6.

for any interstate compact entered into to address the siting of transmission lines to deliver renewable energy.⁵⁹ The Clean Air Act contains no such provision. Accordingly, Congressional approval will come in either the form of express legislation or implication through the actions of states and the federal government. While the express approval avenue could decrease the likelihood of future litigation under the Compact Clause, it also injects significant timing risk into the process because any multi-state SIP would be contingent upon approval of legislation. The "implied consent" avenue mitigates the timing risks, but carries with it the possibility that litigation could be brought for violation of the Compact Clause since no express action occurred. Under these circumstances, the member states would have to establish that Congress did in fact provide implicit consent.

VII. Initial Conclusions and Takeaways

We offer these tentative conclusions and takeaways based upon the above analysis and discussion:

- States have relatively little time to make crucial decisions regarding EPA's proposed rule, including whether to act individually or on a multi-state basis, which of four state plan pathways to take,

⁵⁹ Energy Policy Act of 2005, Title XII, Subtitle B, Section 1221. The statutory section provides:

(i) INTERSTATE COMPACTS.—(1) The consent of Congress is given for three or more contiguous States to enter into an interstate compact, subject to approval by Congress, establishing regional transmission siting agencies to—

(A) facilitate siting of future electric energy transmission facilities within those States; and

(B) carry out the electric energy transmission siting responsibilities of those States.

(2) The Secretary may provide technical assistance to regional transmission siting agencies established under this subsection.

(3) The regional transmission siting agencies shall have the authority to review, certify, and permit siting of transmission facilities, including facilities in national interest electric transmission corridors (other than facilities on property owned by the United States).

To date, no interstate compacts have been entered into under the statute.

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what state agency(ies) should be responsible to implement a Carbon IRP-like process, how any ISOs or RTOs operating within the state will play a role, and what enforcement and corrective action measures are necessary to ensure compliance with the proposed rule.

- States will need to devise institutional arrangements, which almost certainly will require new legislation, between the state PUC and state environmental regulator to implement carbon-driven resource planning.
- State plans will need to encompass all electric generation units, including those owned or operated by current non-state jurisdictional entities like rural cooperatives and municipal utilities. To the extent a state SIP relies on energy efficiency or demand response, all distribution utilities will need to be brought within carbon IRP planning as well.
- Restructured wholesale markets will require integrated carbon planning across the market areas to ensure adequate capacity and reliability.
- Multi-state plans may be attractive within many regions, particularly when coincident with ISO or RTO footprints.
- Because state interests will be potentially rivalrous, multi-state SIPs will need an enforcement mechanism and may well require congressionally-approved interstate compacts to satisfy EPA requirements of enforceability.
- State SIPs that are adjudged by EPA to be inadequate in terms of enforceable, quantifiable and verifiable reductions of EGU CO₂ emissions equivalent to EPA's goals, and implementation of corrective actions, if necessary, will result in a FIP. A FIP creates legal issues of whether EPA has the authority to force state officials to enforce obligations they do not have authority to enforce under state law, and to engage in resource planning and direct system dispatch.

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EMPLOYMENT EXPERIENCE

Wilkinson Barker Knauer LLP – *June 2012 to present*

Partner: As part of Denver office of WBK, practice focuses on energy and telecommunications matters, including transmission line development, smart grid/demand response, rate cases, resource planning, renewable and conventional energy, commercial contracts, rulemakings, state PUC issues

Squire Sanders & Dempsey – *April 2007 to June 2012*

Of Counsel: Co-founder of SSD Denver Office for regulatory practice in Rocky Mountain region, with emphasis in telecommunications, electric and gas regulatory work, including: high cost fund support; generation resource planning; renewable energy; transmission line development; commercial contracts with energy vendors and demand side management firms; rulemakings; rate cases

Colorado Public Utilities Commission – *January 2003 to January 2007*

Chairman: Responsibilities included conducting quasi-judicial and quasi-legislative proceedings; drafting legal decisions; meeting with the governor, legislators, and utilities regarding proposed legislation; investigating service outages; understanding and deliberating on Phase I and II electric rate cases, generation planning, quality of service, and telecommunications service regulation

Major Cases: Redrafting PUC regulatory rules – Electric, Gas, Telecommunications; 750 MW coal plant certification; Xcel and Aquila rate cases; Xcel integrated resource generation planning; implementation of renewable energy mandates; transmission line approval and disputes; electric price response pilot program; Qwest deregulation case; high cost fund administration; rulemakings

Gorsuch Kirgis LLP - *August 2000 to January 2003*

Senior Assoc: Litigation practice with emphasis in representing electric, gas, and telecommunications utilities before PUC; commercial practice before state and federal district and appellate courts

Colorado Attorney General's Office - *September 1997 to August 2000*

Asst. AG: Represent the Colorado Public Utilities Commission Staff at electric, gas and telecommunications proceedings before the Commission, and the PUC in appeals to District Court, Colorado Supreme Court, and Federal Courts

Wells, Anderson & Race LLC - *September 1995 to September 1997*

Weller, Friedrich LLC - *September 1991 to September 1995*

Assoc.: Civil defense litigation before state and federal courts, including insurance fraud and products liability; appellate practice before U.S. Courts of Appeal

University of Colorado- *January 1990 to May 1991*

Business Law

Instructor: Instructor to 60 undergraduate students for 3 semesters under Professor Ed Gac; two lectures per week; Socratic teaching method; graded on written work assignments, testing, and class participation

LEGAL AND UNDERGRADUATE EDUCATION

Degree/Honors: University of Colorado School of Law, Juris Doctor, 1991
Rank: 17/154 (Top 15%)
University of Colorado Law Review

University of Illinois, May, 1988
B.S. in Business Administration; Emphasis in Economics
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SPEECHES AND PAPERS

I have given speeches and presented papers to, among others, the Federal Communications Bar Association, Colorado Bar Association, University of Colorado, CLE International, National Association of Regulatory Utility Commissioners, Federalist Society, Western Chapter of the Energy Bar Association, Silicon Flatirons Telecommunications Program, Colorado Rural Energy Association, Midwest Energy Association, EUCL, and Law Seminars International regarding the following topics:

- Federal Energy Policy Act of 2005
- Solar and wind energy development
- Natural gas price volatility
- Generation resources, planning, and reliability
- RPS Mandates
- Transmission Line Disputes
- Rate Case issues
- Regional Transmission Organizations and Standard Market Design
- Renewable energy and demand side management
- Advanced meter and price response programs
- Federal and state telecommunications jurisdiction and preemption
- Legal and policy issues related to VoIP, wireless services, the Universal Service Fund, unbundled network elements, and inter-carrier compensation
- Rural ILEC issues and disputes
- Telecommunications Act of 1996
- Telecommunications deregulation

Chairman LUMMIS. And I thank all the witnesses for their testimony and for being here today.

We will now begin Member questions. The Chair will at this point recognize herself for five minutes.

First of all, Mr. Sopkin, you mentioned in your testimony rural cooperatives, which are a big component of providers of electrical power in my very rural State of Wyoming, as well as in Colorado, your home State. Are there unique difficulties for States with rural electric co-ops in being able to hit a 70 percent gas utilization rate?

Mr. SOPKIN. Thank you, Chairman. And if I could have Slide 2 shown, I think that would give you an idea of what rural cooperatives are up against.

[Slide.]

Mr. SOPKIN. This is a—this slide was released by the Colorado Air Quality Control Commission and it—what it does is it shows where the EPA's 2030 goal is, which is a limit of 1,108 pounds per megawatt hour and it superimposes that on top of every electric generating unit resource in Colorado. This shows you that every coal unit is in violation of the EPA rule on a pure rate emissions basis. The ones that are under the red line are all gas units. One gas unit actually exceeds this limit. And what you can see from this is that many of these coal plants are operated by rurals and municipals and so they are going to be affected pretty dramatically by this rule.

As far as the 70 percent dispatch, there are many questions about that. In particular, the national utilization average for combined cycle units, gas units, is 48 percent. The EPA standard pushes that up to 70 percent. In most States the utilization rate is somewhere around 30 or 40 percent. Now, why is that? It is because running that gas combined cycle unit is more expensive than the baseload unit that they traditionally run on an 80 or 90 percent basis. It also could be because they don't have the adequate gas line—gas pipeline infrastructure to do it or the electricity transmission rights to do it. So EPA just simply did the cookie-cutter approach of every State, go to 70 percent, without knowing whether a State can actually achieve that because you have to delve deep into whether those transmission rights, those—the pipeline infrastructure is there. But also it is probably going to result in significant rate increases because it is more expensive to run a gas unit than a baseload unit.

Chairman LUMMIS. Thank you. I would also like to ask Mr. McConnell a question about the EPA targets. How reasonable are they? Let's look at coal generators. Can they improve their heat rate by six percent. As the gentleman from Colorado stated, overall utilization to 70 percent for natural gas combined cycle; States meeting renewable energy deployment targets of 13 percent nationwide; end-user energy efficiency improvements, are these targets realistic?

Mr. MCCONNELL. You know, I am all for regulations and environmental responsibility. I am having a hard time figuring out why we are talking about deployment and execution of something that fundamentally doesn't impact the environment. The targets that have been set are all about finding a mechanism to eliminate coal and

ultimately natural gas from our energy mix and require renewables to be deployed.

Now, it is dressed up to look like there is some sort of technical evaluation behind it, but in fact the targets that you just cited are not only difficult to achieve but require advanced technology, advanced development of that technology, and are not something that people will be able to make that decision to go to in the time frame that has been proposed. And so, again, we are in a situation where we are talking about deployment and yet we are getting no value for it.

Chairman LUMMIS. I thank the gentleman. My time is expired.

And I do want to allow Mrs. Johnson, the Member from Texas and Ranking Member, to ask questions for five minutes.

Ms. JOHNSON. Thank you very much.

Recently, three thought leaders from different backgrounds and political ideologies—Michael Bloomberg, Henry Paulson, and Tom Steyer—came together to study the impacts of climate change would have on American businesses. This effort culminated in the report called “Risky Business: The Economic Risk of Climate Change in the United States.” And, Madam Chairman, I would like to submit this by unanimous consent for the record.

Chairman LUMMIS. Without objection.

[The information appears in Appendix II]

Ms. JOHNSON. The report didn’t parse words stating unequivocally “every year that goes by without a comprehensive public and private sector response to climate change is a year that locks in future climate events that will have a far more devastating effect on our local, regional, and national economies.”

Dr. Cash, as I understand it, many businesses already include climate risk as part of their business model. Can you comment on the engagement and interest in businesses in Massachusetts and the Northeast in achieving carbon reductions?

And the second question, what are the potential impacts to the economy of Massachusetts and its businesses if we do not address climate change now?

Mr. CASH. Thank you very much, Ranking Member Johnson. I will actually take those in reverse order because one builds on the other.

We think there—and the science shows and the evidence shows that there is already impacts on climate change and all you need to do is to be in any part of the country where we see high-impact weather events happening that are happening much more frequently than had previously been happening. In the Northeast we struggled with Super Storm Sandy, Irene, a freak October snowstorm. All of those happened while I was a PUC Commissioner and the outages that lasted days and days and days was certainly something that we struggled with. And there is no question that a coastal State like Massachusetts is dealing with sea level rise already.

Businesses are already concerned and are already making plans to deal with climate change. There is no question that in the insurance industry they are addressing climate change. There is no question in the development community they are looking at extra expenses in development along coastal areas. And in the public sec-

tor we are very concerned about infrastructure. That is one of the primary reasons that action on climate change is so fundamentally important because we want to avoid those kinds of large problems that we are going to see on a greater scale in the future. And we see huge economic opportunities to address this problem in terms of clean energy development.

Ms. JOHNSON. Thank you.

Now, in your testimony you indicate that significant pollution reductions achieved in the Northeast were due to a combination of factors, but the Regional Greenhouse Gas Initiative has been a driver. You also conclude that implementation of the Clean Power Plan will mirror what has happened in Massachusetts over the past five years—last eight years but on a national scale. Can you please describe in more detail what has happened over the last eight years in Massachusetts?

Mr. CASH. I can. One of the most exciting things that happened is this growth of the clean energy sector in jobs that go all the way across the value chain that employs people who have Ph.D.'s, that employ architects, plumbers, electricians, those who come to your house to weatherize it, to put in insulation. It is across-the-board value chain job growth that happened in Massachusetts that can't be put overseas. And it has been done—the Regional Greenhouse Gas Initiative has been done using a market-based approach.

And one of the things that I find kind of interesting about the concerns that are raised is there seems to be a lack of confidence that our private sector can step up. What we have done in Massachusetts and across the Northeast is set a clear target, clear market rules, and the private sector has stepped up with innovation after innovation after innovation seeking to capture that world market where we know there is going to be greater demand for electricity in China, and India, et cetera. I am not sure why we want to cede that, cede the growth to India, China, Germany in terms of innovation, entrepreneurship, and economic development. That is what our country is founded on and that is what this kind of regulatory package will allow, the unleashing of that kind of entrepreneurial spirit.

The other piece that I think has been fundamentally important is our use of energy efficiency, and perhaps at some later point I can talk more about that because that is savings across the board, residential customers and business customers as well.

Ms. JOHNSON. Thank you. My time is expired. Thank you very much.

Chairman LUMMIS. I thank you very much.

I recognize the gentleman from Arizona, Mr. Schweikert.

Mr. SCHWEIKERT. Thank you, Madam Chairman.

This is one of those occasions where you have dozens of questions and only a few minutes to do it in, so let me grind into a couple things that I fret about. For my panel, who has actually worked at the EPA? My understanding is in the modeling that the modeling is ultimately proprietary to the EPA, is that correct?

Mr. HOLMSTEAD. I think it is actually proprietary to an EPA contractor.

Mr. SCHWEIKERT. How do you make public policy and not have that model available for everyone to vet and make sure that—be-

cause who knows? Is it stringent enough; is it too stringent? Is there noise in the model? I am trying to understand from, you know, a discussion at the state level to the industry level to the activist level, how do you make public policy on a proprietary model?

Mr. HOLMSTEAD. Well, that question has been raised many times. EPA's answer is, well, you can have your own models and model the same thing, and in fact if you pay a lot of money, there is a way to have the same contractor run something similar. But here is what I would say. For most of these models, the big issue is the assumptions that go into them and it is pretty easy to be skeptical of EPA's assumptions without necessarily—so I agree with your question but just take a look at the assumptions that they do acknowledge publicly and you will see how unrealistic they are.

Mr. SCHWEIKERT. Yeah. And I want to make it very clear for my brothers and sisters on the Committee and everyone else in the room, when I say model, I actually mean from the raw data sets because we also know if you all remember your basic statistics class, that is where you get to really, you know, mess with your inputs.

And this one just sort of eats at me so I might as well share it and get it off my chest. An article from a couple months ago, EPA Chief promotes—or, excuse me, “EPA Chief Promises to Go after Republicans Who Question Agency Science.” And in the article it makes it very clear. I love this quote, “We're coming for you.” So if you question the data, question the science, they are going to come for us? And then the arrogance of the comments of, well, we have real scientists and if you are not part of the EPA infrastructure, you don't count as a real scientist. Is this just noise or is this the actual arrogance that comes out of the EPA? I know it—okay—

Mr. MCCONNELL. We saw it in spades at DOE. We had opportunities to do interagency collaboration and in fact many times it was just frankly dismissed.

Mr. SCHWEIKERT. Who do I have on the panel that has actually worked at the Department of Energy?

For Department of Energy, this is your area of expertise; were you requested to build or participate or do some of the modeling? Because my understanding being from out West where, you know, we have this great difficulty trying to explain to States like Massachusetts and stuff the scale and the distances we run through and that it is more than just that facility, it is my pipelines, it is my mileage of, you know, power lines, the distances we have to cover. So a long way to ask the question, DOE, were you asked? Were you contracted for—to model the actual energy side of this?

Mr. MCCONNELL. Well, first of all, I think it is a great story that has been told here about Massachusetts. I think we all have to recognize that they are less than one percent of the total energy generated in the United States so it is a very unique story to a very small place. And it is a great story but it is a very small part of our world.

At DOE a simple example we got a 650-page document on Friday afternoon at 3:00 and were asked for a response back by 10:00 a.m. on Monday. Now if my folks at DOE hadn't worked all weekend,

we wouldn't have had a chance to respond, and after we responded, we barely got a thank you and many of the corrections that were made were regretfully accepted but it was the kind of disingenuous interagency collaboration that often was very puzzling.

Mr. SCHWEIKERT. And so you are saying from a technical standpoint the relationship DOE and EPA—I mean how did they react when you provided them those corrections to the data?

Mr. MCCONNELL. Reluctant acceptance, but in fact I think it was more of a box-checking exercise to show that interagency collaboration occurred when it really didn't.

Mr. SCHWEIKERT. Okay. Thank you, Madam Chairman.

Chairman LUMMIS. The gentleman yields back.

The Chair now recognizes the gentlelady from Oregon, Ms. Bonamici.

Ms. BONAMICI. Thank you very much, Madam Chairwoman. And thank you to the witnesses for appearing here today.

This is an issue that is a high priority for my constituents, and before I go into questions, I just wanted to say a few words about the economic arguments we are hearing today. I know that a lot of my fellow Committee Members have heard me rave about Oregon and I do realize that in some ways we face different conditions from the conditions experienced by some of my colleagues. In Oregon, for example, we are currently phasing out our last coal-fired power plant. We have abundant hydroelectric power and that means that the reduction target given to our State by the EPA is quite a bit different from targets given to States that rely on coal power for electricity.

But I also want to say that Oregon's economy is uniquely reliant on natural resources, and hence, our economy is threatened by the impacts of climate change. My constituents see the cost of inaction as startlingly high. We consider what might happen to our wine industry, for example, if the global temperatures continue to rise, what is happening to our commercial fishing and shellfish industry as the ocean chemistry changes because of high levels of carbon dioxide in the atmosphere.

And so while the EPA's proposed rule is being analyzed by the State Departments of Environmental Quality, our utility sector, and others who will participate in its implementation, they are seeing forward progress in carbon reduction as welcome news in Oregon.

And I know, Commissioner Cash, you spoke about RGGI. I just want to mention that our Pacific Coast Collaborative has worked on a Pacific Coast Action Plan on Climate and Energy, and that is a collaboration among not only States, the States of California, Oregon, and Washington, but also British Columbia to combat climate change. And our region is really becoming a center of innovation and investment in the clean fuels and technologies.

And I know, Mr. McConnell, you mentioned the importance of developing new technologies, attracting private capital for infrastructure. All of this is turning into jobs, as you, Dr. Cash, recognized was happening in Massachusetts.

So even though, yes, Massachusetts is just one, as Mr. McConnell recognized, one State, when we look at the regional partnerships that are being implemented and moving forward, I think we

see a lot of potential to have the same kind of results that they have seen in Massachusetts on a regional scale.

So I wonder, Dr. Cash, could you talk a little bit—it was an interesting discussion about collaboration or the alleged lack thereof with the EPA. Can you recommend any improvements that could have been made to the outreach process but also talk about whether your agency and others in the RGGI group were consulted during the development of the proposed rule?

Mr. CASH. Thank you very much. That is an excellent question and I am glad I have an opportunity to respond.

I think in the development of the rule there was actually a lot of outreach, and it wasn't just to States like Massachusetts. My understanding from talking to colleagues when I was in—a member of NARUC as a Commissioner—Public Utilities Commissioner, was that the EPA reached out quite a bit all across the country from the highest level—Commissioner level down to the staff level, that the inputs into models and to how they analyze this was done with a lot of input from States, from other agencies as well. The Department of Energy, et cetera, was very engaged in this as well.

So I think that kind of process was a very robust one and has continued to be a robust one since the rule was announced that EPA has been holding meetings at—through all of their regions and our staff has been in contact with the technical staff at EPA almost nonstop. So that outreach has definitely been there.

In terms of the regional concern, I knew it might be addressed that Massachusetts is a small State. I get that. But part of what has happened in RGGI is that it hasn't been just our State. It hasn't just been the one percent. It has been all of the RGGI States, the New England States down to the mid-Atlantic States, down to Maryland and Delaware have been part of this. And all across that region, which is a significant amount of population in the country, a significant amount of the energy use, a significant mix of different energy sources, we have seen reductions of 40 percent while the regional economic advances by seven percent. And we have seen this huge growth in the innovation sector of the—in—all across these States. And it is actually not just these States. We see this throughout the—all of the United States.

Ms. BONAMICI. Thank you, Dr. Cash.

And in my remaining few seconds, I just want to mention that, you know, we have had many discussions about the development of technology in the Committee and also in the Environment Subcommittee on which I am the Ranking Member. We have had hearings about this issue. And I want to point out that historically, if you look at the development of technology, there is a lot more incentive for the companies to develop technology and for investment in the development of technology when there is a requirement that the technology is—there is a demand for it. So when there is a requirement, then the technology is developed. If it is not required, there is not as much incentive for the development of that technology.

So I yield back. I am over time. I yield back. Thank you, Madam Chairwoman.

Chairman LUMMIS. I thank the gentlelady.

The Chair now recognizes the gentleman from Oklahoma, Mr. Bridenstine.

Mr. BRIDENSTINE. Thank you, Madam Chair.

First of all, I would like to thank the whole panel for being here and thank you for your time and your service. I would especially like to thank Mr. McConnell for your great service to my alma mater Rice University and it is—while we may not win many football games, we have got some amazing technical research capabilities and I am glad you are there to help us with those things.

When President Obama was a candidate in 2008, he pledged to the San Francisco Chronicle that he would bankrupt the coal industry. These rules from the EPA are nothing more than his attempt to fulfill this campaign promise. When you look at the practical effects that this rule will have, no other conclusion can be made than this president is trying to kill coal.

As several of you mentioned in your testimonies and what I have heard from utilities and co-ops back in Oklahoma, the assumptions the EPA made regarding efficiency improvements were utterly unrealistic. The timeline for implementation was egregiously short and electricity prices will go up, particularly in States like mine, the State of Oklahoma, who rely heavily on coal.

Last year, coal-fired power plants accounted for nearly 60 percent of electricity generation in the State of Oklahoma, and because of that, we enjoy rates that are well under the national average. This is why I find the EPA's claims of unprecedented outreach to stakeholders to be rather egregious, because if they did, they obviously ignored feedback that they got from my part of the country in Oklahoma.

Further, as we have heard, this plan amounts to the EPA remaking the electricity system in each State, something that has never been under the purview of this agency. There are other Federal agencies with expertise in this area, namely, DOE. And I am interested if they were ever approached by the EPA regarding this aspect of electricity generation.

Mr. McConnell, as a former member of this Administration, what can you tell me about the nature of interagency collaboration under this President?

Mr. MCCONNELL. Well, I think, as I had mentioned earlier, it was an awkward dance because very often the inconvenient truths of technical evaluation didn't fit the political agenda and that made it very difficult to actually have any collaboration, and in fact, as time went on, the communications became almost zero.

I think the other thing that I would like to respond to as well earlier about technology is that if we truly have an administration that believes in an all-of-the-above energy strategy and we really want to do something about the environment because we have been talking about that a lot today about climate change and everything else, I believe it is an important topic as well, but passing this regulation isn't going to do anything about the climate change. That is what is so strange about all of this conversation.

And to the point of if we want to do something about it, what we have to do is invest in clean technologies to enable the fuels that we are using that can be reliable and affordable for not only our country but for the rest of the world, we need to get on with

that task, not defund the fossil energy organization at DOE while everything else gets the money for the windmills and the solar panels. It is a difficult conversation. It is hard to understand.

Mr. BRIDENSTINE. For the record, how much was the fossil part of DOE? How much was that cut during your time there?

Mr. MCCONNELL. Well, it got to the point where it was on and all over the—the period of time during my tenure it was about 40 percent per year, and most recently, some of the continued work that has come in you see the cuts continuing. So it is not an all-of-the-above strategy by any stretch.

Mr. BRIDENSTINE. So when you say they were cutting research opportunities for fossil, were the other opportunities for wind and solar, were they being cut at 40 percent per year as well?

Mr. MCCONNELL. No, not at all. The DOE budget was continually increased during that entire time, and so the fundamentals around the technology that are so important around carbon capture, utilization, and storage, to promote the ability to put technology in place that people will want to use, not to legislatively make them use, is a huge transition. It drives a market, it drives an opportunity, and it also opens up global acceptance for technology rather than trying to moralize with the rest of the world so they will do what we tell them to do.

Mr. BRIDENSTINE. Thank you, Madam Chair. I yield back.

Chairman LUMMIS. I thank the gentleman.

The Chair now recognizes the gentlelady from Florida, Ms. Wilson.

Ms. WILSON. Thank you so much, Chairman Lummis, for holding this hearing, and thank you to our witnesses for being here today.

I am from Florida and Florida is ground zero for climate change in America. Because of our location and geography, Floridians feel the effect of climate change more than any other region of the United States. We see firsthand the results of rising sea levels as seawater floods onto the streets of Miami. We feel the effects of increasingly powerful, increasingly common hurricanes and tropical storms that batter our State every year. On top of these devastating effects, climate change is quickly eroding Florida's beaches. These effects of climate change have caused millions and millions of dollars of damage to Florida's infrastructure, as well as reducing the number of tourists visiting Florida, further hurting our economy.

These impacts are here and we feel them now, yet we know that even more are coming. We have to act now. Pretending this is not a serious problem and delaying the hard decisions will make it—climate change more expensive and more difficult to deal with in the future. Frankly, we owe our children and grandchildren better than kicking the problem down the road for them to deal with.

That is why I applaud President Obama and the EPA for proposing the Clean Power Plan. This plan will prevent 140,000 to 150,000 asthma attacks in children. It will also prevent thousands of premature deaths. The Clean Power Plan is the result of unprecedented proposal outreach by the EPA, which engaged a broad range of stakeholders in developing this plan. As a result of this outreach, the Clean Power Plan provides States with broad flexi-

bility to design plans that reflect the individual policy objectives of the State and reflects its own unique circumstances.

By implementing this plan, the United States can lead the international community in efforts to address climate change while growing our clean energy sector and improving our economy. Done correctly, addressing climate change will create jobs and we should be about creating jobs. In fact, jobs, jobs, jobs should be the mantra of this Congress.

Climate change is no longer just a theory; it is our reality. So I implore my fellow Members of Congress to support this plan and help address climate change for future generations.

Madam Chair, I have a question.

Dr. Cash, can you talk about your experiences in Massachusetts, what you have done, and I would like to know how your State's successes could be able to be duplicated in Florida and around the country. And also talk about the regional initiatives, what benefits they present and how to best encourage more States to adopt these initiatives.

Mr. CASH. Thank you very much, Ms. Wilson. A couple of comments on that.

Again, I want to go back to the comment I made about low-hanging fruit. Almost without this regulatory package it seems like there is huge opportunities on energy efficiency. Again, this is not something particular to Massachusetts. Yes, we have old housing stock but there is old housing stock all throughout the country that were not built to high energy efficiency codes. And so energy efficiency is essentially something that puts money back in the pockets of ratepayers. I still don't really understand why that isn't seen as the first fuel. Before coal, before natural gas, before wind and solar, we should be looking at energy efficiency as the first fuel and that is something that I know that in Florida there have already been advances made, particularly on the demand response side on those hot, hot summer days when people can opt to turn down their air-conditioners a little bit and they make money on that and that reduces cost for everybody in the system.

The other point is I have often wondered about the Sunshine State and solar energy in the Sunshine State. And you are talking about jobs, jobs, jobs. If there were policies that advanced solar in Florida the way that it does in Massachusetts, in New Jersey, in California, and many, many other States now, I think that we would see many more installation jobs, electrician jobs, et cetera, and all of that would work to decrease the amount of demand that is on the whole system and make the system more reliable, not less reliable.

Chairman LUMMIS. The gentlelady yields back.

The Chair recognizes the gentleman from New York, Mr. Collins.

Mr. COLLINS. Thank you, Madam Chair.

Mr. McConnell, you and I share a couple things, both engineers, both MBAs. I have also spent my life in the energy industry starting with Westinghouse Electric. My background is in nuclear, it is in coal, it is in gas. I even owned a wind company for a while in the late '70s. We were producing components for the new-found wind energy driven solely by tax credits where none of the wind

turbines even worked. So I have got extensive—almost 30 plus years in that area.

So let me just start with a sign in my office, “In God We Trust, All Others Bring Data.”

So as you have pointed out what you saw in the DOE was a political agenda. I think that is obvious. So if I could—before I run through some things, just to address Dr. Cash for a minute, I just looked up some data. RGGI. I am from New York, setting aside Alaska and Hawaii, setting them aside—they are pretty unique—let me tell you the 8 most expensive States in this country for electricity. They are Massachusetts, Connecticut, New York, Rhode Island, Vermont, New Hampshire, New Jersey, and Maine. I think they are all RGGI States. So let’s call it out for what it is.

Mr. McConnell, you have got a lot of experience and I think some of what I will say is probably rhetorical but I think it is good to put it on the record. If the United States didn’t produce any industrial CO₂, none whatsoever, no power plants, no nothing, I have heard that that might reduce the total CO₂ produced in the world by about two percent. Is that correct?

Mr. MCCONNELL. Yeah.

Mr. COLLINS. So to answer the gentlewoman from Oregon, if the United States didn’t have any coal-producing power plants, no gas power plants, no automobiles, no nothing, at best it might help Oregon, even if you accept that, by two percent maybe, sort of. In other words, this is a political agenda. I think it is obvious to anyone when you look at the data.

If I look at the different costs of producing electricity, nuclear, coal, gas, hydro, and then throw in wind and solar, wind and solar is the most expensive, two times, four times, eight times. So is it safe to say the only reason we have a wind and solar energy is tax subsidies? Absent those, you wouldn’t have them?

Mr. MCCONNELL. Yes, that is right.

Mr. COLLINS. Is it also a statement of fact, rhetorical question, that every last dollar we spend, whether it is on tax subsidies or not is borrowed from China? So isn’t it fair to say we are borrowing from China, money, so our neighbors can put solar panels on their house? Is that a fair statement? You are chuckling but it is. I mean rhetorically if every last dollar is borrowed and solar and wind only exist, only exist on subsidies, if we did not have tax subsidies, there wouldn’t be a single solar panel or wind turbine going up in the United States of America, and it has been that way since the 1970s and I was part of that back in the 1970s where the joke was the wind turbine manufacturers put up the wind turbine. Back then, they were putting wooden blades on the wind turbines pretending they would work. They get their tax subsidy and laugh all the way to the bank. That is how this industry started. It is still there. They do work today. Technology has come a long way, but my view is the government exists to help develop technology, not to pick winners and losers. This is a political agenda. The States that we just talked about are these RGGI States, the most expensive in the country, and we talk about jobs, jobs, and jobs, the cost of energy is a major part of it.

So in the remaining minute, carbon sequester, which I know quite a bit about, you are going to pump the CO₂ into the ground,

quite deeply into the ground, and you are going to cap it, is that a proven technology as in understanding the potential—we talk about the environment—the potential environmental consequences of pumping CO₂ into the ground?

Mr. MCCONNELL. No, it is not a proven technology inasmuch as carbon capture and storage as a waste disposal of CO₂. But I can offer you some encouraging thoughts. CO₂ has been used for enhanced oil recovery in this country for well over 50 years. When it goes into the formation, it brings up additional oil that otherwise wouldn't come up, and in the process of doing so, in those geological formations it also is safely and permanently stored and has been in many areas across this country and in Canada as well.

It is a market-based opportunity to utilize CO₂ and safely and permanently store it. Our challenge is to broadly deploy this in other places across our country and frankly the world. The technology behind that is part of what the Department of Energy has tried to bring forward, and to declare it ready today is disingenuous. It is not.

Mr. COLLINS. Well—

Mr. MCCONNELL. But the technology needs to be developed so it can be.

Mr. COLLINS. My time is expired but I would make one closing statement. And as the county executive in Erie County, when the environmentalists—as the environmentalists talk about fighting CO₂ emissions, and they don't like hydrofracking because we are creating hydrofracking down in the earth, these same folks, I don't know how they can support carbon sequester, pumping gas down in there. And I can tell you as the county executive, I did not allow that to proceed in our county right on the Great Lakes, one of the greatest freshwater bodies in America where they wanted to carbon sequester. I said not under my watch. But the same environmentalists that seem to care about the environment don't like hydrofracking sit there and say let's sequester carbon underground next to the Great Lakes. It makes no sense to me. I yield back.

Chairman LUMMIS. The gentleman's time is expired.

The Chair now recognizes the gentlewoman from Connecticut, Ms. Esty.

Ms. ESTY. Thank you, Madam Chairman.

And to Dr. Cash, welcome from a fellow RGGI State in Connecticut. Glad to have you here.

There are two topics I would like to discuss. One is electrical reliability, the reliability of the grid for those of us in the Northeast and what we went through with Sandy and other storms, that is the first topic. And the other is on the impact on consumers, again, as has been mentioned by my colleagues. Connecticut and Massachusetts and New York are high-cost States for virtually everything, I can assure you. Electricity is not alone among those.

So first turning to reliability, I know we have found in Connecticut where I know a little bit about the electrical situation that by the low-hanging fruit, the economizing efforts we have been undertaking, we have been able to take pressure off the grid at precisely those times when there has been most demand, those August days when thunderstorms roll through. Could you talk a little bit about the RGGI experience, your own in Massachusetts and with

your colleagues throughout the RGGI States of how that intersection between what we have been able to do and how that impacts an aging infrastructure and frankly national security concerns about reliability of the grid?

Mr. CASH. Thank you, Representative Esty. Excellent questions.

On the reliability side what has happened is in part the RGGI funds that have come from the RGGI program, so from the generators, has gone essentially to customers who can use those funds for energy efficiency programs. And that is customers across the board, residential customers, businesses, commercial entities, those whose bottom line is very important. And I forget which Member mentioned that energy costs are a very important part of the business bottom line for companies. And what they have done is availed themselves of those revenues and used them for better lighting, weatherization, getting out old motors and getting variable speed motors, all getting huge savings.

And what that has led to is a remarkable thing in the Northeast, which is we have load growth of 2 to three percent, would have load growth of 2 to three percent because our economy is growing, people are buying more laptops, more cell phones, all that kind of stuff, and what we have essentially done by our energy efficiency programs—so again giving money back to the customers to retrofit their homes—is we have come to zero load growth, so same economic development, zero load growth. And that means we have avoided building 2,000 megawatts of new energy, new generation. No more transmission lines for those, no new generation, 2,000 megawatts, huge savings. So—and that has made the system more reliable, right? So on the hot summer day you don't need all that.

And so that is one way, and the other is by the use of solar, which, as you mentioned, is working at that peak time of day. And we think that as solar becomes more expansive in the Northeast, we will see even more and more of that.

Ms. ESTY. Well, let's turn to consumers and the cost. We find I can say in Connecticut where I am working very hard to bring manufacturing back because I know my colleagues in Massachusetts are as well, there tends to be an obsession with the kilowatt hour cost as opposed to the actual—and how much is your energy costing if you are using less energy than your overall cost is lower?

And just to give you an example, FuelCell Energy based in Danbury, Connecticut, is benefiting from some of these targeted investments on basic R&D. They are finding it is cheaper for them to produce in Danbury, Connecticut, massive fuel cells that they are shipping to Korea. They are shipping to Korea from Connecticut because it is in fact cheaper because our productivity is so high—

Mr. CASH. Um-hum.

Ms. ESTY. —and they can produce a product that the Koreans are very happy to reduce their reliance on other fuel sources. So I think it is just an example of again it is the all-in cost.

Can you talk a little bit—first, I would like to introduce into the record if I can, Madam Chairman, the Analysis Group report that you referenced in your testimony. I would like to submit that for the record because I think that provides more detailed—could you describe on the consumer's end communities in Massachusetts how

this has impacted the bottom line of the bills they pay, not the kilowatt hour cost but the bills they end up paying?

Mr. CASH. Well, actually, the story is really good on both those counts. As I mentioned before, our rates have dropped by about eight percent in the RGGI region. Even if they had gone up by the 1 to two percent that was predicted, it would have meant lower bills. So higher rates, but because less is being demanded and the price of energy would be lower and less energy being used, the bills across the region would be lower as well.

And I absolutely concede the point that Mr. Collins was raising before about the RGGI States having the most expensive electricity in the country, that is absolutely true. And by the way, you and I share something. I was—born and grew up in New York, more downstate, and that was one of the driving reasons that we got engaged in this, for the cost savings. And as I mentioned, it has led to cost savings, not cost increases. We have seen across the board these cost increases even with renewable energy, which at the beginning has been more expensive. Onshore wind, though, is not more expensive now. We see that throughout the country. We see that in Texas where it is competitive. And we see that in New England where it is competitive. And solar has been dropping by 30 to 40 percent.

And while you mentioned the subsidies that are now received, of course we have historical subsidies to fossil fuels that go back 100 years. So clearly the playing field is not level for renewables at this point, and these subsidies at both States and the Federal Government are doing, or trying to, get that level playing field so we can see the kind of cost reductions both on rates and bills that this kind of regulation and what state activities are doing throughout the country are reaping for their customers.

Chairman LUMMIS. The gentlewoman's time is expired.

Ms. ESTY. Thank you.

Chairman LUMMIS. And without objection her submission will be entered in the record.

[The information appears in Appendix II]

Chairman LUMMIS. The Chair now recognizes the gentleman from Texas, Mr. Weber.

Mr. WEBER. Thank you, Madam Chair.

Earlier, one of you all said in your testimony that these rules were applying to 49 States I think. Was that you, Mr. Holmstead?

Mr. HOLMSTEAD. Yes, that is right.

Mr. WEBER. And what State is it they don't apply to?

Mr. HOLMSTEAD. You know, I can't—I think it may be Vermont—

Mr. WEBER. Is that right?

Mr. HOLMSTEAD. —because Vermont doesn't have any coal-fired power plants, any even legacy plants. So I think it is only 49 States and the District of Columbia that are covered.

Mr. WEBER. I got you. I got you. Well, I was hoping you were going to say Texas because, you know, Texas has its own grid and we get things right in Texas and we are part of that lower—the rate that I think Chris Collins beat me to the punch on. I was going to bring that out.

You were talking about CO₂ carbon capture sequestration. Do any of you all know where the only really huge facility with the carbon capture sequestration is?

Mr. Sopkin—is it Sopkin—where would that be?

Mr. SOPKIN. I believe you are referring to the Kemper facility in Mississippi or not?

Mr. WEBER. No.

Mr. SOPKIN. Okay.

Mr. WEBER. They are in the process of a building that—

Mr. SOPKIN. That is right.

Mr. WEBER. —right now at huge cost overruns incidentally.

It would happen to be in Port Arthur, Texas. Would you like to guess whose district that is in? That is in my district. It was at a cost of about \$400 million; 60 percent of that was supplied by the DOE. You want to talk about a nice subsidy? Sixty percent of that 400 and something million so it was like 200 and—what would that be, 240 or 50 million dollars by the Department of Energy through the American Reinvestment and Recovery Act.

How many of you all think that is duplicable in the private industry? Anybody? Mr. Cash?

Mr. CASH. Are you asking does the Federal Government subsidize the private industry—

Mr. WEBER. I won't—

Mr. CASH. Is that what you mean? I am unclear on your question. I am sorry.

Mr. WEBER. I thought that was pretty clear.

Mr. CASH. Okay.

Mr. WEBER. How many of you think it is duplicable in the private industry without the subsidies?

Mr. CASH. No, there are clearly some things that are not ready for the market—

Mr. WEBER. Right.

Mr. CASH. —and there is no question that throughout the history of this country the Federal Government has stepped in to—

Mr. WEBER. Okay.

Mr. CASH. —provide subsidies, and fossil fuels—

Mr. WEBER. Right.

Mr. CASH. —is one of them.

Mr. WEBER. And I want to point that out that in my district we have firsthand experience of that. EOR, enhanced oil recovery, there is a company down in our area that does a lot of that. They do an absolute lot of that enhanced oil recovery, so we know how it works, Chuck, in our area.

I do want to go back to some of the data and the stuff, the rules, and I—Mr. McConnell, you said you worked for the DOE? When the rules were being formulated by the EPA regarding this, did they seek—were you able to give input in that?

Mr. MCCONNELL. The point that I am trying to make is that a true collaborative effort would have been considerably different than what I observed.

Mr. WEBER. Okay.

Mr. MCCONNELL. And I observed what was a box-checking exercise to say that it occurred but in fact was de minimis.

Mr. WEBER. But were you personally able to give input in there or were you prevented from doing that?

Mr. MCCONNELL. We were able to make inputs and never able to actually observe whether they were received and entered. It was simply a communication and then at that point the EPA was fundamentally in charge with whatever they wanted to report.

Mr. WEBER. So that is what you are calling you just checked the box and you never knew what they did with that?

Mr. MCCONNELL. Well, I didn't check the box; the EPA did because they were required to do "interagency collaboration."

Mr. WEBER. And that was their method?

Mr. MCCONNELL. Yes.

Mr. WEBER. And so they signed off on doing interagency collaboration.

I want to respond to some comments made from the gentlelady from Connecticut. And, Mr. Cash, you said you went after the low-hanging fruit. You wanted energy efficiency to be the first form of energy. And then of course Chris Collins brought out that you all have the most expensive electricity in the country. Is it true that in producing anything manufacturing that the more of it you produce, the greater the economy of scale and the greater cost savings you ought to have?

Mr. CASH. Often, that is the case.

Mr. WEBER. Often or most of the time?

Mr. CASH. I don't know but I know that often that is the case, that economies of scale will mean better use of—

Mr. WEBER. So if we had less burdensome and unnecessary regulations in permitting and in production, we could actually produce more electricity and it might even be at a lower cost. Would you agree with that?

Mr. CASH. I would agree that there are situations where that is true.

Mr. WEBER. So when that impacts the elderly and those on fixed incomes or, as one of my colleagues said, well, just everything in New England is higher, it makes me realize why 1,500 people a day are moving to Texas, okay, in our area—

Mr. CASH. Um-hum.

Mr. WEBER. —which all the while if you looked at our government charts, there with the TCEQ, we are actually reducing not only our CO₂ but our noxious gases.

Mr. CASH. Um-hum.

Mr. WEBER. And by the EPA's own admission—or should I say emission—70 percent of noxious gases come from non-stationary point sources or what we would call vehicles.

Mr. CASH. Yeah.

Mr. WEBER. How do you think those 1,500 people a day are getting to Texas? Cars and trucks? I am just thinking, you know. So maybe a reduction of those rules would help us actually produce power more efficiently and less costly for some of our constituents.

Madam—oh, Mr. Chair now, I yield back.

Mr. NEUGEBAUER. [Presiding] I thank the gentleman and now the gentleman from North Dakota, Mr. Cramer, is recognized for five minutes.

Mr. CRAMER. Thank you, Mr. Chair. Thanks to all the panelists. And it is hard to know where to begin.

I might just state for the benefit of my Texas friend that while 1,500 people move to Texas, the fastest rate of growth is in North Dakota where the price of electricity at the end of May is \$8.62 a kilowatt hour, the lowest in the country, and I—while I appreciate—and by the way, I love any technology that would expand the lifespan of our coal mines and coal plants while at the same time expanding the lifespan of the Bakken crude oil so carbon capture for tertiary oil recovery is a very good technology that I hope someday is truly ready for prime time.

But we have talked about interagency or the lack of interagency collaboration, which concerns me, the lack of it, in a big way. But we have really rarely talked so far about the other obvious agency that has been ignored here and that is the Federal Energy Regulatory Commission or the FERC, who I am not even sure why we would need if we have a rule like this, not to mention the NERC and the others.

I spent, as Commissioner Sopkin may know, nearly ten years as the—as a Public Service Commissioner in North Dakota, and multistate integrated resource planning was hard enough just being multistate, but now to have to throw this into the mix, it boggles my mind how we even could do it. I am very proud of the fact that—and I am one that has resisted many times to call for a comprehensive national energy policy. We have a really good energy policy. It is called lowest cost. The dispatchers dispatch the lowest-priced electricity. It works in a market-based economy quite well. How in the world would we expect a utility like Basin Electric, for example, a rural electric cooperative, G&T, that has its own multistate challenges that doesn't answer to a state regulator, how would we—what are we to tell them? What are we to tell the States of North Dakota, South Dakota, Minnesota, and all of the others about their own integrated resource planning and how is this going to impact them, and North Dakota being an export State, major export State of electricity?

And I am going to begin with Commissioner Sopkin because your white paper, by the way, and Commissioner Gifford's work is very, very good, but maybe if you could just help me understand how I would explain a rule like this to those that are multistate and multi—by the way, multi-resource planners?

Mr. SOPKIN. Well, I think it is difficult to explain frankly. We have looked at the rural and municipal providers across the country and they are very reliant on coal.

Mr. CRAMER. Yeah.

Mr. SOPKIN. And they have made the decision to self-determine their own resource plan. That is part of the reason to be a co-op or muni. And now they are going to have to cede their authority to the EPA and to some state agency that will then tell them how they have to plan their resources. And the big problem here is not having a balanced portfolio.

I would point to a study that just came out this week called "The Value of U.S. Power Supply Diversity" by IHS Energy. This is no right wing think tank here. This is a respected international organization that studies electrical issues. And this I think gives every-

body a good idea of what is going to happen with this EPA plan. It looks at a base case, 2010 to 2012, and it compares to what will happen if we go to a lot of reliance on gas and renewable energy. And the cost of generating electricity will increase \$93 billion per year because of that and consumer pockets are going to be lighter by \$2,100 per year. I won't go through the rest of the report, but this details the direction we are headed.

Mr. CRAMER. Well, and I know some of you are anxious, and Dr. Cash, but I want to get to the efficiency issue as well because we talk about energy efficiency like it is free, and I mean we have a lot of legacy sunk investment that is going to be—the costs are going to be recovered. If we don't use it, it is still going to be recovered. And if we add another resource to it, the legacy stuff still has to be recovered. How do we deal even with energy efficiency and ignore the requirement to recover costs? I mean, you know, I listened to my colleague talking about, yes, the price per kilowatt hour is much higher but the bills are lower and you have said the same thing. We still have to recover costs for things that are being built, don't we? Are we ignoring that in this rule?

Mr. CASH. I don't think that we are ignoring that, and I think that there are a lot of lessons to be gained from two past historical things. One is the acid rain program, which then layered this other thing on top of least cost, and the grids, whether they be state only or regional like PJM or state only like Texas, et cetera, modified the market so that least cost bid stack took into account whatever requirements were required for acid rain, and likewise in the RGGI region where we have ISO New England, NISO and PJM, we layered that on top, and what we have seen is the market respond. The market has responded with innovation, with better technologies, with energy efficiency that even has happened in the requirement for—

Mr. CRAMER. I don't want the rule to get ahead of the technology, and that is what I am afraid we are—

Mr. NEUGEBAUER. I ask unanimous consent that the report that Mr. Sopkin was referring to in his testimony be a part of the record. Without objection, so ordered.

[The information appears in Appendix II]

Mr. NEUGEBAUER. We now go to the gentleman from Indiana. Mr. Bucshon is recognized for five minutes.

Mr. BUCSHON. I thank all of you for being here. Eighty-five percent of the electrical power in Indiana comes from coal, and every coal mine in the state is in my district as well as most of the oil and natural gas. My dad was a coal miner, and that is why I am here today because of the high-paying job in the coal industry. Mom was a nurse.

I want to first of all say I was also a medical doctor prior to coming here, and I know some of the scare tactics I heard from the other side about health issues related to emission, and that is exactly what it is. It is scare tactics. You know why? Because we look at a medical study, and the first thing you look at is who paid for it. Well, the studies that are showing this type of information all paid for by left-leaning global warming advocates based on a model created by a left-leaning global warming advocate who has a financial stake in the model and shamelessly published by a nationally

known organization, which I actually talked to about this and told them I was ashamed of their information. From a health care standpoint, there is no clear data. It is scare tactics to scare the American people, and every time I hear it, it makes me very mad.

The discussion here today is not about whether the temperature of the Earth is changing. Of course it is. It is always changing. When you look back at the history of the Earth, it has changed for hundreds of years, and you know, the other thing is, the EPA admits their current regulations will have no effect on this.

I want to follow up on what Mr. Collins was discussing about energy subsidies. First of all, I believe in an all-of-the-above policy. I think we should pursue absolutely everything. But let me tell you and Mr. Chairman, I was unanimous consent to introduce a few graphs from the Energy Information Administration and the Institute for Energy Research into the record.

Mr. NEUGEBAUER. Without objection, so ordered.

[The information appears in Appendix II]

Mr. BUCSHON. Here is what the facts are, and you can see it—everyone can see it on this chart from where you are sitting—that the solar industry per kilowatt-hour is being subsidized at 1,100 times more than coal, oil and natural gas, and wind is being subsidized at over 80 times more than these others. So all of the states in the Northeast, you are welcome because the taxpayers in Indiana are paying for what is happening in your state.

In the electrical generation sector, renewable energy, 55 percent of the subsidies generated ten percent of the electricity. Wind, 42 percent of the subsidy, 2.3 percent of the electricity generated. Fossil fuel—it is true fossil fuel gets subsidies, and it has for a long time. Sixteen percent of the subsidies but generated the largest share of electricity, 70 percent. And in this chart, solar per kilowatt-hour, \$775.64, coal 64 cents. So I do think economics is part of the mix here, and we do need to look at economics. And the fact of the matter is, is that as we pursue new technology, the Federal Government should support these technologies, but we also need to recognize what the facts are about what we are doing and whether or not we can sustain this.

Mr. Cash, how close to you were brownouts in the Northeast in the cold winter we just had? And be very short because I know what the facts are.

Mr. CASH. We were not. We were not close to brownouts.

Mr. BUCSHON. Okay, because that is interesting because all the energy people in the Midwest tell me that you were within hours of brownouts based on the fact that you had plenty of natural gas, you just didn't have any pipelines to get it to where it needed to go.

Mr. CASH. We had constraints. I don't know if we were hours, but we had constraints and there were concerns.

Mr. BUCSHON. Okay. So you know, when you eliminate 40 percent of the electrical power generation in the entire United States, which is coal, which is the goal of the Administration, get used to it, American people. You are going to not have power 24 hours a day. You are going to have brownouts because the infrastructure is not there.

Mr. Sopkin, do you want to answer that question?

Mr. SOPKIN. Yeah. What happened with these polar vortices in January and February, many of the baseload plants that are soon to be retired because of EPA regulations came to the rescue. Don't take my word for it. The New York Times headline was "coal to the rescue but maybe not next winter," and I offer this as well for the record.

Mr. NEUGEBAUER. Without objection, so ordered.

[The information appears in Appendix II]

Mr. SOPKIN. And what happened is that 89 percent of AEP's coal fleet that is going to be retired next year had to be operated to avert brownouts, and on the subject of energy efficiency, Murray State College had signed up for interruptible program and found out to its dismay that actually you do get interrupted, and they were interrupted with five minutes' notice. Students had to be displaced and there was flooding at the school.

Mr. BUCSHON. Mr. Chairman, I yield back.

Mr. NEUGEBAUER. I thank the gentleman, and now the gentleman from Massachusetts, Mr. Kennedy, is recognized for five minutes.

Mr. KENNEDY. Thank you, Mr. Chairman.

Mr. Cash—Dr. Cash—excuse me—I want to touch base back with you about the interstate compact and the need for one from your opinion.

We have heard testimony today about several assumptions about the operations of multi-state implementation plans, but your testimony seems to indicate that many, if not all of them, are unfounded. Specifically, I believe it was Mr. Sopkin that indicated that enforcement can and should be on an interstate basis and that states should and will insist upon it. I wanted to get your thoughts as to that, and if you can tell us a little bit about what is going on in Massachusetts and RGGI.

Mr. CASH. Thank you very much, Congressman Kennedy.

Certainly, states can take actions by themselves. There is no question, and many, many states across the country have on energy efficiency and other programs. There are many states that avail themselves to solar programs, not just the Northeast, in fact, many in the Southwest. But what is advantageous to an interstate compact, it allows the program to move forward in the most cost-effective way. If it is very costly to reduce emission in Massachusetts but there are plants in New York that can be dialed back more cheaply, you can have a tradable program to do that. That is what the neoconservative economists said before the acid rain debates in the 1980s and 1990s, which incidentally many environmentalists were very concerned about letting the market play here. It has worked perfectly well in acid rain, and it has worked perfectly well, that the market works in the lowest-cost way to get emission is what comes to the fore, and so by having more and more states in an interstate compact, you can have a broader market, a more liquid market that allows that kind of cost-effective economics to work.

Mr. KENNEDY. Thank you, Doctor. And building off of those comments, can you discuss a little bit—again, from your opinion and your experience with Massachusetts—about how EPA's proposed

rule helps Massachusetts and will allow other RGGI states to build off the successes that you have already seen.

Mr. CASH. Sure. So it is kind of interesting. When we were developing RGGI ten years ago when it started, we always thought of it as a potential model for something that could happen at the national level. Again, acid rain was one of the models that had worked on the acid rain side. We thought on carbon this would be a very good approach.

Clearly, as the market gets larger, if there are more and more states that are playing this, when more and more states playing it, it means that there is going to be more innovation and more competition to get that next new energy efficiency or solar product or advancement that is going to drive the cost down and reduce emission, and we see that already. The states that are very engaged in the clean energy sector, there is enormous growth and innovation, and so the larger the market is, the more advantageous it is and the lower the cost will be for emissions reduction. In fact, the cost is negative. In other words, we are saying money.

Mr. KENNEDY. Thank you, Doctor.

Mr. McConnell, thank you for your testimony earlier today. My in-laws actually live right down the street from your university so I have been to Houston more times than I ever thought I would be over the past several years.

Mr. MCCONNELL. You are always welcome.

Mr. KENNEDY. Thank you very, very much.

Sir, you talked about a bit earlier the lack of coordination between—communication between interstate agencies. If I am correct, you finished up your stint at the Department of Energy back in January of 2013, so you haven't actually been part of those official communications back and forth for over a year. Is that right?

Mr. MCCONNELL. Resigned in February of 2013, yes.

Mr. KENNEDY. So is it fair to say that you wouldn't be as involved and your knowledge about the extent of those communications over the course of the past year would be less than they would have been before?

Mr. MCCONNELL. That is absolutely true.

Mr. KENNEDY. Okay. Thank you, sir.

Chairman, I yield back.

Mr. NEUGEBAUER. I thank the gentleman, and now the gentleman from Alabama, Mr. Brooks, is recognized for five minutes.

Mr. BROOKS. Thank you, Mr. Chairman.

Mr. Sopkin, Alabama Attorney General Luther Strange recently testified to Congress that "Since 1915, the Alabama Public Service Commission has guided intrastate electricity development so as to protect ratepayers and ensure reliability. Under EPA's proposed 111(d) guidelines, however, the Commission could continue these efforts only insofar as they comport with EPA's greenhouse gas agenda." What is your opinion on whether the EPA or a public utility commission can do a better job of protecting ratepayer interests?

Mr. SOPKIN. I certainly think a public utility commission is the expert agency that performs the resource planning function best. This is something that most state public utility commissions do all the time, and their highest calling is for reliability and cost. They

need to make sure that service is adequate and safe and rates are just and reasonable. That is found in virtually every statute in the state.

The problem with the EPA plan is, those issues now become secondary to carbon reduction, and as far as EPA flexibility on that subject, it appears that EPA is rejecting exceptions to the carbon reduction rule if a state says we have a problem with feasibility, we have a problem with cost, we have a problem with the age of the units, we have a problem with how this is going to affect our state. Section 111(d) of the statute that EPA is operating under specifically provides that states should have a flexibility to come to the EPA and ask for a case-by-case exception but page 520 of the EPA's proposed guidelines appears to reject that and say that these case-by-case exceptions should not be considered as a basis for adjusting the state emission performance goal or for relieving a state of its obligation to develop and submit an approvable plan that achieves that goal on time. To me, that means that states have no choice but to submit to these carbon caps regardless of these issues of cost and reliability.

Mr. BROOKS. Thank you, Mr. Sopkin.

The next question is going to for Mr. Holmstead, but if anyone else has any insight, please feel free to share it after him.

I think we can all agree that overpopulated poor countries are some of the world's worst polluters and that prosperous economies empower economies and countries like America to pay for expensive pollution control equipment. That being the case, what weight does the EPA give to jobs creation and jobs destruction when the EPA imposes its rules and regulations? And I mention that in particular because in our state, Governor Bentley has made some rather strong comments recently talking about how the EPA and its rules and regulations are basically an attack on jobs in the State of Alabama and are costing us thousands of jobs that our people in the State of Alabama need. So Mr. Holmstead, what insight can you share?

Mr. HOLMSTEAD. EPA is supposed to do studies of job losses caused by Clean Air Act regulations. They have not done that so far. But here is what they do: They count the jobs that they want to create and don't look at the jobs that are destroyed, so we have heard about all the people who are employed installing wind turbines and solar panels and all of those things, and those jobs that are created by government subsidies and government mandates. But they don't look at the jobs that are lost in other sectors and in particular the jobs that are lost because of higher energy costs. So the bottom line is, EPA doesn't really consider that.

Mr. BROOKS. Anybody else want to share any insight?

Mr. CASH. If I may, Congressman Brooks, I think that the EPA, again, like many other states that have taken on these kinds of issues, not just climate but clean energy, see job growth as a very important part of this, and whether it is primary like in the growth in our field of—in our area of solar jobs, wind jobs, or it is a secondary growth, that is, savings through energy efficiency that now stays in the pockets of customers, which stays in the pockets of businesses that can now use that for additional job growth. We see this as a big step forward in that regard.

Mr. BROOKS. Thank you. Any other comments?

Mr. MCCONNELL. I think there is a big difference between jobs in the service industries and real manufacturing and heavy industry, whether it is the petrochemical industry, refining, and some of the burdens of that. The states of Texas, Florida, Illinois, Alabama, your state, this is where 40 percent of the burden of this regulation will be borne, in those states where there is heavy manufacturing and heavy industrial use, and that is the real critical issue here is that many of the other states that are involved with this don't feel that pain near as much.

Mr. BROOKS. Well, thank you. I would just follow up on that just for one or two comments. I would submit that manufacturing and industry are the golden eggs, and if you destroy those golden eggs, there won't be service jobs because those people who are in industry and manufacturing, their incomes are what ultimately are consumed by those who are providing services.

And then finally, inasmuch as the EPA is not—well, I am getting hammered down. I thought last I would have an extra 30 seconds. I don't. Thank you. Have a good day.

Mr. NEUGEBAUER. I thank the gentleman, and now the gentlewoman from Maryland, Ms. Edwards, is recognized for five minutes.

Ms. EDWARDS. Thank you very much, Mr. Chairman, and thank you to our witnesses today.

You know, it is so interesting when you are in Congress how people have different perspectives depending on the state and the district that they come from and represent and here you heard a number of different perspectives, and I guess the way I looked at this EPA rulemaking is that it offers states some flexibility to develop a plan that matches the needs and opportunities of its state, considering the kind of industry and the challenges that that state faces. I know in Maryland, we have taken on this challenge put forward by our Governor to reduce our energy consumption by 15 percent just in a very short time by 2015.

Now, I don't know whether we are going to meet that goal. It is a really big goal. But I think it is important here when we are talking about preserving and protecting the environment, creating jobs for the 21st century, leaving a planet that our children and their grandchildren can enjoy and get the benefit of, then we should set a big goal. Maybe at the end of that time we don't meet those goals but we should try to do that. And so I have looked at this rulemaking as about flexibility.

Dr. Cash, I want to ask you about that because in his testimony, Mr. Sopkin mentions that the proposed rule places severe time constraints on states that are potentially insurmountable, given the need for state legislation, and I think we all recognize that these kind of things don't happen overnight, especially legislation, but it does appear to me that Massachusetts and other RGGI states have been able to accomplish much of what is described in the building blocks in a relatively short amount of time.

So as someone who has been instrumental in developing that legislative basis in Massachusetts that mirrors the intent of the proposed rule, I am curious about hearing your perspective and what

lessons we can learn from the successes that have been achieved by RGGI states in overcoming some of these hurdles.

Mr. CASH. Thank you very much, Congresswoman Edwards, and it has always been a pleasure to be working with Maryland and RGGI on other projects in this area.

First of all, I believe that there will be flexibility even on the legislative versus regulatory side. In RGGI, for example, not every state had to pass legislation. There were already states as Massachusetts was one of them that had the regulatory authority to become part of the market base program that is RGGI.

The other, I think, thing that is interesting is that during the RGGI process, it was a bipartisan approach, and it changed during the—there were different gubernatorial elections during the time but there were both Republican and Democratic governors during that time who saw the economic advantages and there were legislatures that were interested in moving the ball forward.

So while I think that this may be difficult for some states, I think there may be states that have regulatory authority already and I think in the face of this EPA regulation, I think legislators will see the potential opportunities and build in flexibility in their own state rules, which is another thing that we have done in RGGI. For example, each state can apportion the allowances, the revenue that comes from allowances, in different ways. There isn't a cookie cutter way to do it. Different states have done different regulations and different laws that allow themselves to comply with what we have agreed upon to be RGGI but to do it in very different kinds of way. And so that has been a big advantage and one I think that adds to the kind of flexibility that we see here in the EPA rule.

Ms. EDWARDS. Let me just ask about that, because, I mean, there is also some criticism and we have heard it already today about the job creation potential or the negative impact on jobs, and again, I have always thought of this as, you know, here we are, we are in the early parts of the 21st century. The kind of jobs that we have now are not the kind of jobs that we had in the early part of the 20th century. So the fact that we lose jobs in some areas doesn't close off the opportunity in this new sector and a growing sector to create those jobs. Has that been part of your experience as well?

Mr. CASH. That has been part of our experience, and I just want to say very, very clearly, when any of these changes happen and the economic shifts, whether they are because of regulation or just the market, the global market changes, it is very, very difficult and in no way do we minimize the changes that may happen in states that are more dependent on fossil fuels, et cetera. We do not minimize that at all. We have dealt with that in our state. We have had coal plant closings in our state and throughout the region, and we have actually used part of your RGGI funds to assist communities in the transition as those plants have closed down, whether they are in retraining or loss of revenue to the municipality that had the plant as a tax base. So that is something that I think needs to be taken into account.

Ms. EDWARDS. Thank you.

Mr. MCCONNELL. I would like to add a comment to—

Mr. NEUGEBAUER. I am sorry. The time of the gentlewoman is expired.

We will now go to the gentleman from California. Mr. Rohrabacher is recognized for five minutes.

Mr. ROHRABACHER. What would you like to add?

Mr. MCCONNELL. I would like to add that I have been somewhat stunned that we have spent so much time today talking about the states that generate five percent of the energy for the entire United States as a model for the rest of the United States, and I think that is the most troubling aspect of this is looking at that small subset as the model for the rest of the country, which doesn't look anything like the rest of the country.

Mr. ROHRABACHER. And I think you mentioned earlier that the same states actually have higher costs of energy than the rest of the states.

Let me just note that when jobs are really destroyed in our country and whether they are in Maryland or anywhere else, if what is being mandated is a use of what we have as wealth in a country and now it takes more wealth to do something, that means there are fewer jobs because there is not the wealth to create the jobs. That is one of those basics that we know about. One excuse would be for doing that, if you want to eliminate wealth that doesn't need to be eliminated and have the jobs there would be if public health was involved in this, and what I would like to know basically what we are talking about today are regulations that are not really aimed at public health. They are aimed at CO₂ reduction. Is CO₂ a threat to public health?

Mr. CASH. It is a threat to public health.

Mr. ROHRABACHER. CO₂ actually is harmful to humans?

Mr. CASH. Not breathing it in but the impacts of climate change.

Mr. ROHRABACHER. Okay.

Mr. CASH. It is harmful to public health.

Mr. ROHRABACHER. That is enough of that. Let me—

Mr. CASH. And it is also—

Mr. ROHRABACHER. That is totally absurd, so CO₂ is not harmful to human beings, right? But all these other things that we can just conjure up in CO₂ become hazardous to the health of human beings. Frankly, that one extra step is a big step because some people don't believe that CO₂ actually is a major factor in climate change for our planet.

Let me just ask, earlier on we had a—so CO₂ is not harmful to human beings' health itself. Earlier on, Mr. Collins, my colleague, asked about all of these regulations would even in the reduction of CO₂ would only result in a two percent reduction in the production of CO₂. I remember that. I am not sure who—

Mr. HOLMSTEAD. Can I just put this in context?

Mr. ROHRABACHER. Yes.

Mr. HOLMSTEAD. A study came out not that long ago that said if you assume this regulation is fully implemented by 2030—

Mr. ROHRABACHER. Yes.

Mr. HOLMSTEAD. —what would this regulation do, this massive shift in our economy. That would be equal to about 21 days of current emission from coal-fired power plants in China, and by 2030, it is projected that it would be something like 12 days.

Mr. ROHRABACHER. And we are talking about CO₂ production.

Mr. HOLMSTEAD. Right, CO₂ production.

Mr. ROHRABACHER. Which by the way is not harmful to people's health. The byproduct of manufacturing it can be conjured up but CO₂ itself is not harmful, but this reduction of CO₂ that we are talking about, this two percent, is not two percent of what mankind is producing or is it a two percent reduction of what CO₂ represents as part of our atmosphere the two percent reduction, is it not? We are not talking about two percent of the reduction of what CO₂ in the whole atmosphere. We are only talking about a two percent reduction in mankind's addition. Is that correct? Right.

Mr. HOLMSTEAD. Yes, it is, and to be clear about it, this specific regulation is .2 percent of the overall CO₂.

Mr. ROHRABACHER. And let me note that CO₂ then, we are talking about a two percent reduction of what some people think will have a draconian effect on our economy. That is two percent less than one-half of one-tenth of one percent of the atmosphere, not 2 percent—people will think it is two percent of what it is in the atmosphere of CO₂. That is not what we are reducing. We are reducing the one-half of one-tenth percent of the atmosphere, okay, is CO₂, and we are reducing the mankind's percent of that, which is only one-tenth of that. Is that correct? So what we are really talking about is one-tenth of one-half of one percent of the atmosphere that would be affected by this at all.

In order to—let me just state, CO₂ again is not harmful to people's health. Reducing it by this teeny weeny microscopic amount and hurting people's jobs, et cetera, throwing us into turmoil and restructuring our business is absurd. Thank you.

Mr. NEUGEBAUER. I thank the gentleman, and now the gentleman from Illinois, Mr. Hultgren, is recognized for five minutes.

Mr. HULTGREN. Thank you, Mr. Chairman. Thank you all. I want to thank the witnesses for being here. This is certainly an important hearing as we try and understand what legal authority under Section 111(d) EPA has to promulgate these rules.

With unemployment rates still disproportionately high in my State of Illinois, what my constituents are worried about is jobs. Manufacturing is a vital part of my district's economy, and this sector is one that will always be energy intensive. They have every incentive to find efficiency gains, which the industry has been actively doing, but many now fear that this was all for naught, considering that increased energy costs, especially in the short term, will end up making them pay more even though they are using less.

Mr. Holmstead, I wonder if I could address my question not you. The Clean Power Plan is comprised of two main parts, to my understanding, one, the state-specific goals to lower carbon pollution from power plants, and guidelines to help the states develop their plans for meeting those goals. According to EPA, this framework provides states with the flexibility to choose for themselves, the best set of cost-effective reductions. How does EPA guidance under this plan compare with previous agency guidance for similar performance standards? Is it more or less flexible than the guidance EPA has provided for other sources, and what boundaries for state interpretation has EPA set for its guidance?

Mr. HOLMSTEAD. This is fundamentally different from anything EPA has ever tried to do before, so in the past when they have done guidance, the guidance says here is the kind of plants that you need to regulate, here are the things that you can do to improve the emission rate of those plants, and then states, you go out and you need to develop the standards for these individual plants. I think it is true that this provides much more flexibility than EPA has ever done before but it is flexibility to achieve a goal that can only be accomplished by making these dramatic changes in many ways. So is it flexible? Sure. But it is—someone used the analogy before, you know, they give you six gallons of gas to make it from here to California and say, you know, you are completely flexible, do that any way you want.

Mr. HULTGREN. Mr. McConnell, if I could address this to you, you spoke about the lack of communication between DOE and EPA when putting forward new rules. Earlier this year I asked EPA about their consultation with DOE regarding the technology readiness assessment for your former agency of science to technologies they develop. Their answer was alarming, and echoes your complaints. I wondered at what technology readiness level would you consider a technology to be adequately demonstrated? All of the CCS technologies were at six or below. That is my understanding.

Mr. MCCONNELL. I came here last November and testified about the new coal standards, and in fact, what is absurd about it is that EPA is taking a stance where plants that are either in construction or in engineering development have actually—are examples of demonstrated commercially available technology and declared that that technology would be commercially available in 2016 for new coal-fired power plants.

We have a roadmap and have had a roadmap for a number of years that said it was going to be available in 2020, and that also—it also required that continued funding of the program would be maintained at the then-current rates and then subsequent to that, the government and the Administration has defunded that effort, and so what we have done is, we have taken the money out of the technology development, declared it ready ahead of time. It is a somewhat disingenuous process that says you can use it, you should use it, but you really can't, and then consequently, you are required to make another choice. It is flexibility but it really isn't flexibility.

Mr. HULTGREN. I think you kind of touched on this, but since climate is a global problem, I wonder if you could into a little bit more specifics of what technologies are we not developing right now that nations such as China would be willing to purchase? I am thinking of some of the combustion technologies that provide significant efficiency gains, which seem to be, you know, something this President is not supporting. So I wonder if you could talk a little bit more about that.

Mr. MCCONNELL. Well, many people would use—would say that clean coal and clean fossil technology is an oxymoron, and that is absolutely not true. It is demonstrated in our country we have made enormous progress, and that is when the government has worked with industry to provide that pathway forward, not to

eliminate something but to actually invest in the technology so that it can be deployed.

The world's energy is going to double in the next 50 years. Ninety percent of that doubling will occur in developing countries. Those developing countries are going to use fossil fuels. EIA has already projected that 85 percent of the world's energy will be fossil energy by 2060. So we have an obligation to the rest of the world to develop those clean technologies so we can really make an impact, not do this that doesn't impact anything while we hobble our economy.

Mr. HULTGREN. Good point. Thank you.

Thank you, Chairman. I yield back.

Mr. NEUGEBAUER. I thank the gentleman. I guess the Chair has a question then.

Mr. Holmstead, by the year 2030, EPA believes that the proposed plan would allow the United States to reduce carbon emission from the power sector by 30 percent below the 2005 levels and roughly 17 percent cut from the 2013 levels. To achieve these reductions, EPA calculated a specific emission rate for each state, as you are aware of, by totaling the CO₂ emissions produced by each state's EGUs and dividing it from the total amount of electricity generated by the EGUs. My home State of Texas is looking at a 39 percent cut in emissions by 2030. Is that achievable?

Mr. HOLMSTEAD. It is hard to know. We don't really have kind of good data on that. People are trying to figure that out. But what we do know is that it will be very expensive, and I think that is the—and again, there been some estimate of how expensive that may be. I think people are still trying to figure it out. This is an enormously complicated proposal. But the one thing we can say is, it certainly will put reliability at risk in some areas, and it will be very expensive.

Mr. NEUGEBAUER. This may be a harder question. Do you believe EPA has a sound legal and technical basis for these emission rates and reduction targets for each individual state?

Mr. HOLMSTEAD. Well, that is actually an easy question. I think it is quite clear that this proposal goes far beyond anything EPA is authorized to do under the Clean Air Act, and I just think that is troubling that a regulatory agency would essentially ignore what Congress has given it authority to do.

Mr. NEUGEBAUER. And this weighting formula that EPA came up with for these reduction goals, was that done fairly? If you were going to do it that way, that is a pretty big burden on some of the states that are actually producing electricity.

Mr. HOLMSTEAD. Again, this question is a hard one because EPA went state by state and they said here is how we believe you should change your electric system, right, and they said on a state-by-state basis, we think you should, you know, shift generation this way and you should do energy efficiency programs and you should mandate renewable energy. So it is hard to know if it is fair. What we do know is, EPA went state by state and said here is the way we believe you should change your electricity system.

Mr. MCCONNELL. And I think in our State of Texas, we ought to be concerned because we generate 11 percent of the energy in this country and we are going to bear better than 20 percent of the bur-

den for this, and specifically, the only way Texas can do this because of the pounds per megawatt-hour that have been mandated are going to require us to double the amount of renewable energy we have in our portfolio, approaching 35 percent in our state. So we are being punished because we are the leading renewable state in the country. The formula goes to making that a baseline for ability to move forward. So in our state, we should be very concerned.

Mr. NEUGEBAUER. I thank the gentleman. Unfortunately, the Chair has to close this hearing. I want to thank the witnesses for their valuable testimony and the Members for their questions. The Members of the Committee may have additional questions for you, and we ask that you respond to those in writing. The record will remain open for two weeks for additional comments and written questions from the Members.

The witnesses are excused and this hearing is adjourned. Thank you.

[Whereupon, at 12:14 p.m., the Committee was adjourned.]

Appendix I

ANSWERS TO POST-HEARING QUESTIONS

ANSWERS TO POST-HEARING QUESTIONS

Responses by The Honorable Jeffrey Holmstead

**QUESTIONS FOR THE RECORD
The Honorable Lamar Smith (R-TX)
U.S. House Committee on Science, Space, and Technology**

EPA's Carbon Plan: Failure by Design

Wednesday July 30, 2014

Responses from Jeff Holmstead (in italics below)

1. The Clean Power Plan, which EPA released as part of President Obama's Climate Action Plan, relies on the Agency's authority under Section 111(d) of the Clean Air Act. Based on your experience as Assistant Administrator for EPA's Office of Air and Radiation, can you [identify] what other rules that EPA has issued under this same provision – section 111(d)?

There are only five types of "sources" that have been regulated under Section 111(d). EPA has used this section:

- 1. To regulate acid mist from sulfuric acid plants*
- 2. To regulate flourides from Phosphate fertilizer plants*
- 3. To regulate flourides from Primary aluminum plants*
- 4. To regulate total reduced sulfur from Kraft pulp plants*
- 5. To regulate landfill gases from Municipal solid waste landfills.*

a. Was the Agency's approach in developing the Clean Power Plan consistent with these previous rulemakings? (Including recent 111(b) regulations recently and concurrently proposed)?

The Agency's approach in the proposed Clean Power Plan is altogether different from anything it has done in these other regulations and goes well beyond the authority that Congress has given EPA under the Clean Air Act. It is also inconsistent with the approach that EPA has proposed for new power plants under Section 111(b). The key differences are discussed below.

b. If not, could you explain how they differ and whether this inconsistency could have legal ramifications?

The five regulations listed above fall squarely within EPA's authority under the Clean Air Act because they required states to set a "standard of performance" for each source of this type that was located within their borders. Under these regulations, each source must comply with an allowable emission rate that can be achieved by using the "best system of emission reduction" that achieves a "continuous emission reduction" from that type of facility.

There are only five 111(d) regulations because Section 111(d) can only be used for pollutants that are not regulated under other parts of the Clean Air Act. Virtually all other pollutants are regulated as either "criteria pollutants" or "hazardous air pollutants," so they cannot be regulated under 111(d)

Several environmental groups have argued that, because there is so little precedent under 111(d), EPA is essentially drawing on a blank slate and can be very creative. But this is

misleading because EPA has interpreted the relevant language of the statute dozens of times for many different pollutants from new sources.

Under Section 111, EPA is required to set a “standard of performance” for new plants under Section 111(b), and, under certain circumstances states are required to set a “standard of performance” for existing plants under Section 111(d). The relevant statutory language is the same – a “standard of performance.”

Until now, a standard of performance has always been an emissions rate that can be achieved by the “best system of emission reduction” that “has been adequately demonstrated” for controlling emissions at the type of plant being regulated. So, for example, EPA has proposed a standard of performance for carbon emissions from new coal-fired power plants of 1,100 lbs per megawatt hour, based on the use of CCS, which EPA believes has been adequately demonstrated.

For existing power plants (but not new one), EPA is now taking the position that the standard of performance does not apply to an individual plant, but to the whole “electricity system” in a state. This is inconsistent with how EPA has defined “standard of performance” for more than 40 years. It is also inconsistent with the standard of performance they have proposed for new coal-fired plants. If EPA really believes that “beyond the fence line” actions can be used as a standard of performance, it could achieve much great reduction in carbon emissions from new plants at a lower cost by allowing new plants to invest in energy efficiency and demand response programs rather than CCS.

EPA justifies its proposed 111(d) approach based on a statutory provision that 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.”

*EPA focuses on the word “system,” which is certainly a broad term. And the statute does define a standard of performance, in part, as “the degree of emission limitation achievable through the application of the best system of emissions reduction.” The statute also provides that this system must ensure a “continuous emission reduction” from a source being regulated. But the key legal question in this case is not what a “system” may be. The statute says that a standard of performance must be based on “the **application** of the best system of emission reduction.” In this case, the question is “the application of the system to what?” EPA says, “to anything that produces or uses electricity.” But the answer, according to the statute and almost 40 years of regulatory history, is “the type of facility being regulated.” In the context of Section 111(d), this means to “any existing source,” as long as it ensures a “continuous emission reduction” from that source and that, “in applying a standard of performance to any particular source,” the state is able to “take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.”*

2. Administrator McCarthy recently said that EPA sees its Carbon Plan as “an opportunity to look at a short-and long-term investment strategy, not a pollution control strategy.”

- a. Do you believe that Congress authorized EPA to oversee investment strategy for the electric sector?

Congress never authorized EPA to impose or oversee a new investment strategy for the power sector. Nor has it authorized EPA to set a statewide carbon emission rate based on EPA's view as to how that state should restructure its electricity system and reduce the demand for electricity. Under Section 111(d), EPA is authorized only to require states to establish a standard of performance that applies to individual plants.

- b. Administrator McCarthy also recently said that is Carbon Plan can be complied with "in ways that are very far from pollution control technologies." Isn't this precisely why Congress required that these regulations be based "inside the fence-line" – so that EPA doesn't end up regulating things beyond what a specific rule covers?

In the Clean Air Act, Congress gave EPA the authority to implement a number of different regulatory programs. When it implements these programs, EPA must follow the approach that Congress intended. Under Section 111(d), EPA may require states to set a "standard of performance" for certain types of existing sources, but EPA may only require a state to set standards that will continuously control emissions at a source when that source is operating. It does not have authority to set statewide standards based on EPA's views as to how a state should change its electricity system.

3. Do you believe EPA has the authority, under a CAA section 111 rule regulating fossil fueled power plants to issue a federal implementation plan that orders a state to generate electricity from renewable sources not regulated by the rule?

No. EPA does not have authority to require that renewable generating sources be constructed or used. Such requirements can be imposed by states but not by EPA or any other federal agency.

- a. Do you believe EPA has the authority to issue a federal implementation plan that dictates how electricity is dispatched in a state?

EPA does have authority to require power plants to install demonstrated pollution control technology. Regulations such as MATS and CSAPR impose requirements that make certain coal-fired power plants more expensive to operate and thus have an impact on dispatch. However, EPA cannot simply mandate changes in dispatch as it has tried to do in its 111(d) proposal. EPA is attempting to take a certain amount of business from coal-fired power plants and transfer it to combined cycle natural-gas fired plants. Congress never gave EPA authority to mandate this type of "environmental dispatch."

- b. Do you believe EPA has the authority to issue a federal implementation plan creating federally enforceable building efficiency codes?

No. Again, it is clear that EPA does not have this authority. It can only implement the statutory authority it has received from Congress, and Congress has never given EPA authority to impose building efficiency codes or any other type of end-user efficiency mandates.

c. Do you believe EPA has the authority to issue a federal implementation plan that orders states to require nuclear power plants operate?

No. EPA does not have authority to require any type of power plant to operate or to require that a certain amount of a state's electricity be obtained from any particular generating facility or type of facility.

d. Do you believe EPA has the authority to issue a federal implementation plan that orders states to reduce electricity use by 1.5% each year?

No. EPA simply does not have authority to impose requirements to reduce the demand for electricity.

4. In addition to claiming flexibility, EPA has said the proposal reflects "the important role of states as full partners with the federal government in cutting pollution." However, each State Plan must still be reviewed and approved by EPA.

a. If a state legislature creates an energy efficiency or renewable energy program and later determines that is not in the best interest of the state, can the legislature go back and change the programs it has created.

Under current law, a state legislature is free to change any type of energy efficiency program or renewable energy mandate that has been put in place in that state. This would no longer be the case if EPA's proposal is adopted. Under the proposal, if EPA has approved a state 111(d) plan that includes a renewable energy mandate or end-user efficiency program, the state legislature cannot change those programs without approval from EPA. If a state legislature does try to change such programs without EPA approval, EPA and environmental activists would still be able to enforce the original programs even if they had been rescinded by the state legislature.

b. Is there currently adequate oversight to ensure there is no discrimination against specific states? For example, some states and localities have worked to attract industry and importantly, good paying jobs through low energy costs.

As noted above, EPA's proposal would require each state to change its electricity system based on EPA's view of how electricity should be generated and used in each state. Generally, states that have been able to keep electricity prices low have chosen to rely primarily on coal-fired generation. This would no longer be possible under EPA's proposal, as all states would have to shift away from coal and adopt requirements that would increase the cost of electricity.

c. Does EPA have the authority under Section 111(d) to impose its own regulations on utilities if a state's plan is deemed to be insufficient to meet EPA's CO2 reduction level? Who makes this determination?

Under the Clean Air Act, EPA does have authority to impose a federal 111(d) plan in a state if the state fails to adopt a "satisfactory" 111(d) plan of its own. EPA makes the determination as to whether a state plan is satisfactory. However, there are serious legal questions as to whether EPA could adopt a plan that contains all the measures it wants states to adopt. I cannot think of any Clean Air Act provision, for example, that would authorize EPA to change the way power

plants are dispatched, to impose renewable energy mandates, or to create programs to reduce power demand.

5. Is there any particular section or authority in the Clean Air Act that gives the EPA the power to eliminate the use of a particular fuel?

No. Congress has not given EPA authority to eliminate any type of fuel. EPA can require plant owners and operators to use the best system of emission reduction that has been adequately demonstrated to control emissions from a plant burning coal, or a plant burning natural gas, or a plant burning petcoke, but it cannot prohibit anyone from building any particular type of plant. Nor can it mandate a shift from one fuel to another at existing plants

6. The Federal Power Act has long prevented the federal government from interfering with state management of intrastate electricity matters. Yet, under the proposed Carbon Plan, EPA would have to approve how states operate their respective electricity systems.

a. This proposal overturns nearly a century of state flexibility on electricity matters – is EPA’s plan really providing “flexibility” for states?

As a legal matter, EPA’s proposal would provide states with flexibility to meet EPA’s mandated statewide emission rates in any way they choose. As a practical matter, however, states would have very limited flexibility. Given the proposed timeframes and emission reduction requirements, most states would effectively be required to adopt the measures that EPA has used to calculate each state’s emission rate. In fact, based on conversations with a number of state and power sector officials, it may not be possible for some states to meet EPA’s proposed near-term requirements at all.

b. The federal Power Act Restricts FERC authority to interstate electricity transmission and wholesale electricity prices, and leaves electricity generation and intrastate distribution to the States. Yet the proposed Carbon Plan short-circuits this separation, and places EPA in control of intrastate electricity matters. Under what legal authority is EPA claiming authority over the grid that Congress didn’t even give to FERC?

*EPA claims to have discovered such authority in a provision of the Clean Air Act that has been in place for almost 40 years -- Section 111(d). I do not believe the courts will uphold EPA’s new interpretation of Section 111(d), which would give EPA rather breathtaking new authority to require states to change the way that electricity is generated and used within their borders. As the Supreme Court said in its recent decision in *UARG v. EPA*, another case involving EPA’s authority to regulate carbon emissions:*

*When an agency claims to discover in a long-extant statute an unheralded power to regulate ‘a significant portion of the American economy,’ *Brown & Williamson*, 529 U. S., at 159, we typically greet its announcement with a measure of skepticism. We expect Congress to speak clearly if it wishes to assign to an agency decisions of vast ‘economic and political significance.’”*

QUESTIONS FOR THE RECORD
The Honorable Kevin Cramer (R-ND)
U.S. House Committee on Science, Space, and Technology

EPA's Carbon Plan: Failure by Design

Wednesday July 30, 2014

Responses from Jeff Holmstead (in bold type below)

1. In the proposed rule, it seems to me the EPA is assuming electricity is generated and delivered only within one state. How does the EPA in the proposed rule address, for example, renewable electricity produced in one state but then delivered in another?

This is one of the issues that many outside parties have asked EPA to address. It now appears that EPA may allow a state to "take credit" for renewable energy generated in another state if there is an acceptable program for tracking "renewable energy credits" or RECs. It is unclear, however, whether this would be permissible under the Clean Air Act. Another similar problem arises when a state creates an end-user energy efficiency program that reduces demand at fossil-fuel power plants in another state. Under EPA's proposal, the state that created the program would not get any credit for it that would apply to the state's carbon reduction requirement. Such a program would only benefit the state where the power plant is located.

2. What kind of challenges does this impose on regulators trying to write a state implementation plan?

These issues are well discussed in a white paper prepared by the energy consulting firm of Wilkinson, Barker, and Knauer, entitled "State Implementation of CO₂ Rules: Institutional Issues with State and Multi-State Implementation and Enforcement." This paper has now been provided to the Committee by one of the authors, Greg Sopkin, who testified before the Committee at the July 30th hearing. This white paper does a good job of discussing the practical issues facing state regulators trying to develop a 111(d) plan that would be satisfactory to EPA.

3. What authority does the EPA have, or a state for that matter, to regulate electricity demand, as proposed in one of the EPA's building blocks?

Some states have authorized a state agency or commission to impose programs designed to reduce the demand for electricity. This type of authority can only be granted by the state legislature. Neither EPA nor any other federal agency has authority to regulate the demand for electricity.

4. In your experience, is the timeline that the EPA has proposed feasible? One-year for development of state implementation plans, two-years if developing a regional plan?

I think even EPA recognizes that these timelines are not be feasible in most cases. In most states, as discussed in the Wilkinson, Barker, and Knauer White Paper, the State legislature will need to adopt new legislation to give a regulatory agency or commission the authority to impose the

types of programs envisioned by EPA's various building blocks. Assuming that such legislation is adopted, then state agencies or commissions will need to deal with a number of different stakeholders to develop a proposed 111(d) plan, including detailed regulations, that complies with the state legislation and will satisfy EPA. All states have some type of administrative procedure act that would require such a proposal to be published for public comment. Then, after a public comment period, the implementing agencies would need to issue a final rule to impose the necessary regulatory requirements. It is simply not plausible that states would be able to accomplish all these steps, many of which will be very controversial, in one or two years.

Responses by The Honorable Charles McConnell

**QUESTIONS FOR THE RECORD
The Honorable Lamar Smith (R-TX)
U.S. House Committee on Science, Space, and Technology**

EPA's Carbon Plan: Failure by Design

Wednesday July 30, 2014

Questions for the Honorable Charles McConnell

1. EPA's Carbon Plan assumes coal-powered power plants can reasonably increase their efficiency by 6%. Yet in the Energy Policy Act of 2005, Congress created a tax credit for "advanced coal based generation technology" that increased power plant efficiency by that same amount. In other words, Congress thought a 6% efficiency improvement was so complex that it required "advanced technology" expensive enough to require billions in tax credits to defray the costs. In your experience, how much would it take for a power plant to improve its efficiency by 6%? How long would such improvements maintain a 6% increase?

Increasing efficiency by 6% (or by any percentage) is very arbitrary and not grounded in any science or engineering detail. It ignores the existing operating conditions and dynamic operation of the generation in a system. It also ignores the age of the unit and existing efficiency. Old units can improve much more than new efficient units so the logic of a percentage improvement is not sound.

This regulatory target makes it nearly impossible for new, efficient units to achieve the targets and the old units that might have enough upgrade space to achieve 6% are likely to be less efficient than newer units, even with the upgrades.

The other aspect of an arbitrary 6% associated with this Carbon Plan is the impact on these coal plants resulting from other rules and requirements - all of which will be additive to overall performance. And yet make it impossible to project or invest as the target continues to move.

All that said, if a plant were to attempt to achieve the 6% and needed to design, engineer, construct and operate, a 5 - 7 year period to implement is reasonable. How long the 6% would be maintained would largely hinge on future regulatory requirements imposed. So who knows?

This is a disingenuous target that is proposed and the EPA knows no coal-fired generator would pursue due to uncertainty of the investment. Especially true for new facilities (5-10 years old) that are already highly efficient, as a 6% improvement to the best units in the fleet is impossible with today's technology. And, by the way, any changes to existing units would expose the operator to a NSPR and no company wishes to expend the cost or be exposed to the uncertainty.

2. Was cost to deploy and timeline to deploy integrated into the rulemaking for necessary infrastructure for:
 - a. Natural gas pipelines?
 - b. Transmission electric wires?
 - c. System reliability (volts and vars for stability)?

a. Natural gas pipelines - no

b. Transmission electric wires - no

c. System reliability (volts and vars for stability) -no

My testimony highlighted the other agencies that could have been engaged to report findings – there are none.

3. What is resource adequacy as a defined term and how relevant is it to system reliability?

Resource adequacy is a term that speaks only to installed capacity measured against anticipated demand. It does not factor in load variation, maintenance and reliability, weather anomalies, reserve margin requirements in existing service areas or by PUC's in states.

In short, it is the least representative term that can be applied to reliable and dependable service and is far short of a sufficient term or analysis to meet the test of full disclosure. It also takes no account of delivered cost of electric service to customers.

4. In your testimony, you say that environmental policy cannot be made in a vacuum. In the context of the Administration's climate regulations, how were critical issues such as energy affordability and security addressed?

Energy affordability and system reliability and security were not factored in any manner whatsoever.

No studies.

No projections.

No effort to pursue any of this information.

Pursuit of study information would have produced inconvenient truths that were not pursued for obvious reasons. The facts would be compelling against the Rule III (d) in that energy would be far less secure and much more expensive on average to the US customer. Worse yet, it would be especially injurious to the six states that bear 40% of the CO2 reduction requirements.

Manufacturing will become uncompetitive (as it is in most of the states that will not be as greatly impacted by the regulation) and customers in the six states will see their power bills increase by three and four times the current base.

5. EPA has a proprietary model that it uses to project the energy and cost impacts of its proposed rules. But because this model is hidden from public view, we cannot confirm that EPA's projections are credible.
- Was DOE asked to perform an energy and economic impact analysis of the power plant rules? Would this be helpful? What do you think it might show?
 - Have you looked at EPA's assumptions; do you see problems? What if some of these variables changed? For example, if new EPA regulations on hydraulic fracturing cause the price to spike – how might that affect EPA's conclusions?

a. I was not at DOE over the last year. My previous experience in the formulation of new coal plant regulations was what I referenced in terms of my previous experience with the EPA. That experience was that EPA did not request analysis - only a perfunctory review of "resource adequacy" - and that was done by DOE's policy office and not of my department of fossil fuels or the Office of Electricity.

Yes, it would be helpful.

It would show what I spoke of in the answer to question 4 above.

b. There are a myriad of problems because the assumption is but one assumption. There are no scenarios on forward price or availability. Natural gas is assumed available everywhere - it's not.

Natural gas price is constant - it will surely not be. In fact, prices and availability are assumed constant and no rational sound analysis would contemplate such scenarios.

A business analysis requires scenario analysis and probability of such scenarios occurring. A transparent finding must include the cases and performance expectations of the case and an honest call on cost and reliability that is inclusive of necessary investment. Analyzing jobs "gained" and ignoring any "Jobs destructions" is also disingenuous.

The DOE, Department of Commerce and other government agencies have access to internal and external sources of information that can truly inform the scenario analysis. There is no evidence that any information is provided or even sought after.

Responses by Mr. David Cash

**QUESTIONS FOR THE RECORD
The Honorable Lamar Smith (R-TX)
U.S. House Committee on Science, Space, and Technology**

EPA's Carbon Plan: Failure by Design

Wednesday July 30, 2014

Questions for Dr. David Cash

1. As we all know, my home state of Texas is a large state; producing the most electricity in the nation, which in turn makes it the largest carbon emitter in the nation. In 2011, Texas emitted 656 million metric tons of carbon dioxide, accounting for about 12% of the nation's total carbon emissions.

The EPA's proposed clean power rule requires Texas to cut its carbon emissions by roughly 39% from 2005 levels by 2030. As you've outlined in your testimony Dr. Cash, there are different ways that your state of Massachusetts has gone about cutting carbon emissions. I think Texas has already taken steps in the right direction including becoming the first state to establish an Energy Efficiency Resource Standard requiring utilities to utilize end-use efficiency to reduce load growth; and investing in cleaner forms of power generation such as natural gas, which makes up 41% of our electrical generation. Wind energy in the state of Texas makes up 10% of our electrical generation and our state has the largest wind capacity in the nation, more than double our next state competitor.

Is the state of Texas on the right path to complying with any final rule that the EPA comes out with and what other steps can we undergo to accomplish this goal?

Response:

Texas is on the right path for compliance. I don't know the specifics of the Energy Efficiency Resource Standard, but energy efficiency is by far the cheapest "fuel" for getting emissions reductions. In many states, aggressive energy efficiency programs have led to lower costs for residential and business customers that utilize the programs, and for all customers as electricity demand overall all declines leading to lower prices. This has also led to both greater reliability since the system is not stressed as much, and lower emissions of local air pollution and greenhouse gases. As you note, Congressman Veasey, Texas has definitely been a leader in wind energy, and therefore has shown that development of large-scale renewable resources can happen – providing benefits to the developer, land owners and creating clean energy jobs in Texas. I believe that the EPA rules will provide greater incentives for both energy efficiency and renewable energy that can be captured by Texas, creating economic benefits while lowering emissions.

2. One concern that I do have in regard to the EPA's Clean Power Rule is the possible effect on utility prices for consumers. According to the Energy Information Administration, Texas households have an average annual electricity cost of roughly \$1,801, one of the highest in the nation. Given the EPA proposed rule estimates utility costs for consumers may rise, I am concerned for many of my constituents who currently struggle with energy costs.
 - a. Dr. Cash, in your testimony you stated when RGGI was originally developed, you predicted electricity rates to rise 1-2%, but instead they have dropped 8%. Can you explain what this drop may have possibly been attributed to?
 - b. How can we ensure, if this rule goes forward, that we protect consumers from rising electricity rates?

Response:

- A. *The drop in electricity rates and bills in New England in the last several years has been attributed to several forces: greater supply of cheap natural gas that has been driven by the market; expansion of energy efficiency programs throughout the region, resulting in close-to-zero load growth; greater deployment of wind and solar that has depressed forward capacity and real-time energy market prices.*
- B. *Aggressive energy efficiency programs help keep consumers' rates low. In addition, in the Regional Greenhouse Gas Initiative emissions trading programs, there are a variety of mechanisms like banking that help keep rates low. In addition, by auctioning allowances and returning those funds to consumers in the form of rebates/credits or energy efficiency programs, we are able to protect rate payers.*

Responses by Mr. Gregory Sopkin

Responses to Questions for the Record
U.S. Committee on Science, Space, and Technology

EPA's Carbon Plan: Failure by Design

1. What is the problem with states enacting new laws that exercise resource planning jurisdiction over all EGU's- isn't this something they do now?

Many utilities, specifically rural electric associations or cooperatives and municipal utilities, are not subject to resource planning jurisdiction of state public utilities commissions. These entities self-determine their own resource plans based on cost, reliability, and public policy considerations. For example, when I served as Chairman of the Colorado Public Utilities Commission (CPUC), the CPUC had no rate or resource planning authority over Tri-State Generation and Transmission Association, Inc. (Tri-State), Colorado Springs Utilities, or the Platte River Power Authority. This regulatory architecture exists in Colorado today. Therefore, new state legislation would be necessary to bring these non-jurisdictional utilities under the resource planning jurisdiction of the relevant state utility regulator such that the CPUC would have approval authority over all generators and utilities in a state Section 111(d) plan. Colorado is a specific example of a state where such legislation would be necessary. Most, if not all, other states subject to EPA's proposed rule to regulate carbon dioxide emissions (CO₂ Emission Guidelines) face this same issue.

Beyond these legal issues, there are also practical issues and concerns associated with this potential jurisdictional expansion. Many cooperatives or municipal utilities have never submitted a resource plan before. Therefore, these entities may not have the resources to develop and litigate a resource plan on a tight timeline. Cost also factors into this equation, as developing and litigating resource plans can cost each utility hundreds of thousands of dollars – if not more. Cooperative and municipal utilities' ratepayers ultimately bear these increased compliance costs, from obtaining approval of the resource plan to building the necessary internal functions to develop a resource plan.

Attached to my responses please find a white paper I co-authored entitled EPA's CO₂ Rule and 18 States' Resolutions and Legislation. This is a follow-up paper to the white paper submitted along with my testimony and discusses state legislation and resolutions enacted pursuant to Section 111(d). Specifically, it analyzes the interaction of these state laws, which rightly assert state primacy under the statute, and EPA's proposed CO₂ Emission Guidelines.

2. EPA says that one of the options for states is to enter into a multi-state plan.
 - a. Do you foresee any complications with states entering into a multi-state plan?

Yes. Page 46 of EPA's proposed CO₂ Emission Guidelines frames the four general criteria upon which the agency will evaluate and approve or disapprove as state plans under Section 111(d): "1) enforceable measures that reduce EGU CO₂ emissions; 2) projected achievement of emission performance equivalent to the goals established by the EPA, on a timeline equivalent to that in the emission guidelines; 3) quantifiable and verifiable emission reductions; and 4) a

*process for biennial reporting on plan implementation, progress toward achieving CO₂ goals, and implementation of corrective actions, if necessary.*¹

This first criterion is most relevant in evaluating complications associated with multi-state Section 111(d) plans. State plans must be enforceable and the involvement of multiple states, particularly with an aggregated CO₂ performance goal, raises the question of how emission reduction measures are enforced as between states. States should specifically want interstate enforcement authority, i.e., the ability for State A to enforce the terms of the multi-state Section 111(d) plan against State B. Without interstate enforcement authority, State A leaves itself susceptible to any noncompliance on the part of State B or any other participating state, in which case all states involved in the multi-state plan and the actors in those states are subject to the Clean Air Act's significant criminal and civil enforcement regime.

In addition, the Clean Air Act does not allow for interstate enforcement. Research reveals only Clean Air Act provision that explicitly references interstate pollution abatement, Section 126. This statutory provision authorizes downwind states to petition EPA to take action against an upwind state source. It does not, however, authorize State A to enforce against a source in State B, and is silent on remedies as between states if and when state disputes arise.

Finally, interstate enforceability almost certainly demands state legislation and Congressional approval, as discussed in my answer to Question 7 below, because the Compact Clause of the U.S. Constitution is implicated and an interstate compact is required to allow for interstate enforcement.

- b. The EPA refers to the carbon trading program of northeastern states called the Regional Greenhouse Gas Initiative (RGGI) as a good example of how states can enter into a multi-state plan. Do you agree that RGGI is a model that can be followed by all states?

No. Our review of the RGGI reveals fundamental legal problems with this model when EPA's four general approval criteria are applied to it. The major issue is enforceability. Where several states join together and are subject to an aggregate CO₂ performance goal, the measures to achieve that goal are likely not "enforceable measures" unless there is interstate enforceability. Absent interstate enforceability, states cannot depend on the reductions that each state commits to achieving. More importantly, as a matter of law EPA cannot improve a multi-state Section 111(d) plan that lacks interstate enforcement because it does not satisfy the agency's first approval criterion.

Because the RGGI lacks an interstate enforcement mechanism, no state has enforcement power over any other state and any state can leave the RGGI without sanction. States can and do leave the RGGI, and New Jersey serves as a recent, high-profile example. Therefore, any multi-state plan modeled on RGGI would not meet the basic requirement of the proposed CO₂ Emission Guidelines that measures in state plans must be enforceable. Under RGGI, if a state cannot comply with the emission limit or performance goal, it can simply leave the arrangement

¹ Environmental Protection Agency, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (June 18, 2014).

because the RGGI is implemented on a state-by-state basis pursuant to state law (in all states except New York). No terms of the RGGI commit states to continued participation for a fixed period.

Compliance brings me to an additional point. Up until recently, the RGGI CO₂ emission standard was much higher than actual emissions, hence it was easy to meet the standard. These high standards effectively eliminated any possibility of noncompliance. Moreover, because the RGGI states are not tethered together to an aggregated CO₂ performance goal, they operate independently of one another in achieving, or not achieving, compliance with applicable standards. The reductions mandated by EPA's proposed CO₂ Emission Guidelines are much more severe than the RGGI reductions, and states can be dependent upon one another to achieve compliance as a group. Therefore, the likelihood of interstate rivalries and legal disputes increases substantially, which illustrates the need for states to have interstate enforcement mechanisms. The RGGI model lacks this integral component, and therefore is neither approvable by EPA nor advisable for states to pursue.

3. In building block 2 of EPA's proposal, they assume that states can increase gas combined-cycle units to a 70% utilization rate. Do you have any concerns with the technical feasibility of this?

Yes. According to EPA, in 2012 the national average utilization rate for gas combined-cycle units was 46%, so this assumes a significant increase across the board in gas combined-cycle utilization.² Indeed, a recent presentation given by Southwest Power Pool shows that the NGCC capacity utilization rate for NGCC is below 30% on average in its footprint.³ EPA simply assumes that the average utilization rate can be increased over 200% in SPP's region, but utilities cannot make this happen without massive new investment in infrastructure that cannot be completed within EPA's carbon reduction deadlines.

There are numerous reasons for low utilization rates of NGCC capacity, although the reasons will vary on a state-by-state and regional basis. Some of these reasons are:

- (1) Running the natural gas combined-cycle unit is more expensive than running a coal unit but less expensive than building a new coal unit, so the combined-cycle unit is run on an intermediate and not a baseload basis;*
- (2) The utility does not have sufficient unit capacity rights to run the unit more;*
- (3) The utility does not have sufficient gas infrastructure or storage rights to run the unit more;*
- (4) The utility does not have sufficient electric transmission rights to take more power off the unit; or*
- (5) The unit was not designed to run at a 70% utilization and cannot do so without endangering the safety or reliability of the unit itself.*

² 79 Fed. Reg. at 34,857.

³ Southwest Power Pool, Missouri Public Service Commission Presentation, at 6 (Aug. 18, 2014) (hereinafter SPP MPSC PPT), available at https://www.epis.psc.mo.gov/mpsc/commanc/components/view_itemno_details.asp?caseno=EW-2012-0065&attach_id=2015004160.

EPA did not factor any of these considerations into its assumptions under building block 2.

It is also worth considering the practical consequences of the reasoning above. If the first reason listed above is why a particular combined-cycle unit does not have a 70% utilization rate, then electric rates will increase as the utilization rate increases and displaces a cheaper form of electricity. If the second or third reason applies, then either it is impossible to increase the utilization rate or new infrastructure must be built or new transmission rights obtained, both of which come at a high cost. To get a sense of the costs at issue here, gas infrastructure costs can run upwards of \$5 million per mile.⁴ High voltage transmission lines typically cost approximately \$1 to \$2 million per mile, excluding substation costs.⁵ The planning, siting, permitting and construction process involved in both intra- and inter-state pipelines, transmission and generation facility projects is expensive and time-consuming. This process can take up to a decade or longer in some scenarios and the EPA proposed rule provides no compliance alternatives to accommodate this process.

Therefore, it appears that EPA has either ignored or downplayed the infrastructure challenges and economics that limit the capacity factors of existing combined cycle units. To be sure, under any of the scenarios detailed above, customers ultimately lose because of the unfeasible and inaccurate EPA assumption in building block 2.

4. Building block 3 in EPA's proposal assumes that states can increase reliance on renewable energy. The specific amounts EPA puts into each state's mandate is based on what some neighboring states have planned.
 - a. Do you have any concerns with this approach?

Yes. Overall, different states have different quality and quantities of renewable energy available in their state, and it often differs even between neighboring states. This is a direct effect of the reliance of these technologies on natural resources, which are not allocated based upon state or regional borders. For example, all western states are grouped together, including California, Colorado, Montana, Nevada, and Washington. The wind, solar, and geothermal resources in each state differ markedly and some states have legislatively mandated renewable portfolio standards (RPS) and some do not. California and Colorado's RPS percentage is double that of Arizona, Montana and Washington. Idaho and Wyoming have no RPS. These state laws drive the amount of renewable energy penetration in each respective state along with the amount of resources that are available. Notwithstanding these different drivers and nature of resources available, EPA averages them and imposes an assumption on each region. In some sense, citizens of one state are indirectly having the will of the citizens of another state applied imposed upon them, e.g., the imposition of Colorado's RPS statute on Wyoming residents.

⁴ Dean Ellis, Managing Director – Regulatory Affairs, Dynegy, Illinois Commerce Commission US EPA Clean Power Plan Policy Session, Presentation at Illinois Commerce Commission 111(d) Stakeholder Meeting (August 18, 2014).

⁵ See SPP MPSC PPT, at 13.

In addition, expanding renewable energy requires building new or upgrading existing high-voltage transmission lines. According to SPP, for additional electric transmission it “[t]akes up to 8.5 years to perform applicable planning processes and construct transmission upgrades.”⁶ Many transmission projects are subject to staunch opposition legally and politically, which further increase costs and the timeline. In addition, high voltage transmission lines typically cost approximately \$1 to \$2 million per mile, excluding substation costs.⁷ The proposed timelines in the CO₂ Emission Guidelines for a state to submit a Section 111(d) state plan do not even remotely factor in the approval and construction timeline for this essential infrastructure. Nor are these costs considered in EPA’s plan.

- b. Did EPA undertake any specific studies of technical feasibility? Are there things that could be issues such as load pockets? Or reliability concerns?

I do not believe that EPA has adequately studied the technical feasibility of its building block 3 assumptions. Renewable generation is not the same as gas, coal, or nuclear generation. Coal, gas and nuclear are dispatchable on demand, whereas renewable resources, with a few limited exceptions, are not dispatchable resources. Generation that can be counted on to meet peak demand, i.e., dispatchable resources, is counted for purposes of calculating reserve margins, which are typically 15% or higher. Accordingly, EPA cannot simply assume that increased renewable generation will replace dispatchable generation from coal, gas, or nuclear resources. EPA appears to have done so, which raises significant reliability concerns in my view.

Presentations from affected entities at state-level meetings across the country illustrate these reliability concerns. For example, at an Oklahoma Corporation Commission Mr. Lanny Nickell, Vice President of Engineering at Southwest Power Pool (SPP), presented an overview of SPP’s generation assets and the perceived impacts of 111(d) on Oklahoma and its broader territory.⁸ With a 41% reduction target, the rule will have particularly profound impacts on Oklahoma, requiring a 30% increase in gas combined-cycle capacity factor, adding nearly 50% more renewables, and retiring over 3,000 MW of coal generation. The rule would also impact capacity margins across its territory. Generators currently operate with a mandatory 13.8% annual capacity margin requirement, which EPA assumes will decrease to 5% by 2020 and -3.8% by 2024. Of the 14 LSEs served, 9 would be deficient by 2020 and 10 by 2024. Moreover, the additional transmission upgrades would be expensive and time consuming. Like many others, SPP is concerned the timetable does not allow sufficient time for planning, siting, permitting, and constructing the necessary upgrades: “Transmission infrastructure needed to mitigate reliability issues and to support interconnection and delivery of new generation will likely not be available by the time it is needed to facilitate compliance with the EPA’s regulations.”⁹

SPP is in the process of conducting a reliability analysis, with initial results expected any day, as well as an analysis comparing state vs. regional approaches. However, “preliminary results

⁶ See *id.*, at 11.

⁷ See SPP MPSC PPT, at 13.

⁸ Lanny Nickell, Vice President – Engineering, Southwest Power Pool, Oklahoma Corporation Commission Presentation (Aug. 21, 2014), available at <http://www.occeweb.com/DEQ-EPA-Presentations.html>.

⁹ See *id.*

indicate increased thermal overloads and low voltages due to EPA's assumed retirements," which will likely create challenges for meeting applicable reliability standards.¹⁰

- c. Do EPA cost estimates consider the entire cost of new renewables, or does EPA assume that tax payers will continue to provide subsidies for wind and solar production? Is the full cost of these subsidies included in EPA's calculations?

EPA has not performed any kind of state-by-state analysis of costs, so I cannot test their cost assumptions. However, I would note that cost appears to be of little to no concern to EPA in this rulemaking, as it does not allow any exceptions to meeting its carbon standard based on cost or increased customer rates. At a Missouri Public Service Commission (Missouri PSC) workshop on August 18, 2014, Ameren Corporation indicated the likelihood of substantial increased customer rates as a result of the proposed CO₂ Emission Guidelines – and not an insignificant increase at that. Ameren (a utility with approximately 1 million customers in Missouri) projects a \$4 billion increase in costs as a result of EPA's proposed action.¹¹ With costs like that from only a single entity subject to the rule, as a former regulator I do not understand how EPA can justify its complete disregard for costs and customer impacts in designing its proposed rule.

5. EPA claims existing state structures can simply be "extended" to implement the Carbon Plan. Can EPA's plan to regulate, in its words, "from plant to plug" simply be grafted on to preexisting state or regional programs?

No. In fact, EPA takes conflicting positions on the issue of the compatibility of existing state structures and authorities with what is required under the proposed CO₂ Emission Guidelines. For example, in its Technical Support Document (TSD) entitled State Plan Considerations, EPA provides:

[A]n enforceability consideration is whether an IRP, and related public utility commission orders, must include additional requirements to implement certain actions, beyond denial of rate recovery or a change to utility tariffs if a utility fails to meet specified obligations in the IRP. If so, this may require state legislation to provide additional authority to state public utility commissions in some states, or confer additional authority to other agencies (e.g., a state environmental agency).¹²

Accordingly, EPA is clearly contemplating that the authorities provided to state public utilities commissions and/or environmental agencies under existing state law are inadequate to implement key components of a Section 111(d) state plan. The excerpt above relates to utilities or generators already subject to some level of public utilities commission jurisdiction. As discussed in response to Question 1, there are additional and even more significant enforcement

¹⁰ See *id.*

¹¹ Ameren Missouri, Missouri Public Service Commission Presentation (Aug. 18, 2014), available at https://www.eis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EW-2012-0065&attach_id=201500415.

¹² EPA Office of Air and Radiation, State Plan Considerations – Technical Support Document for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, at 15-16, Docket ID No. EPA-HQ-OAR-2013-0602 (June 2014), available at <http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf>.

issues with regard to cooperatives and municipal utilities. Again, EPA recognizes this in its *State Plan Considerations TSD*:

Under a utility-driven portfolio approach, the entire suite of obligations under the plan would be enforceable against the utility company, which would also be an owner and operator of affected EGUs. If there are other affected EGUs in the state that are not owned and operated by a vertically integrated utility, a state plan might need to include other measures that address CO₂ emission performance by these affected EGUs.

A similar approach could be taken by municipally owned utilities or utility cooperatives, which often also engage in an IRP process. However, state public utility commissions (PUCs) often do not regulate these utilities. As a result, implementation of a portfolio approach by these entities would introduce practical enforceability considerations under a state plan.¹³

Given these jurisdictional and enforcement issues, and the fact that they are recognized by EPA, EPA's notion that state structures can be "extended" is alarming as a matter of law. Any "extension" of state agency authority requires the blessing of the legislature, and I believe that legislation is required in the states to implement this rule with enforceable measures.

6. A number of states have worked over the past decade to "de-regulate" their electricity markets. Would EPA's Carbon Plan effectively re-regulate electricity in those states?

Yes, the proposed CO₂ Emission Guidelines may ultimately result in a degree of soft reintegration of the utility function in restructured states. These states opted for competitive generation as a means to lower costs and achieve optimal resource mixes through competition instead of centralized resource planning by state utility commissions or similar entities. The proposed rule, however, necessarily reintroduces a central planning aspect to generation because allowable facilities must now be approved through the regulatory process and portfolios must be balanced by each state. There is no integrated resource planning process in these states, and therefore EPA takes the position that "[a] state-driven portfolio approach" is most suitable for restructured states.¹⁴ A state-driven portfolio approach is described as follows:

Under a state-driven portfolio approach a mix of entities might have enforceable obligations under a state plan. This includes owners and operators of affected EGUs subject to direct emission limits, as well as electric distribution utilities, private or public third-party entities, and state agencies or authorities that administer end-use energy efficiency and renewable energy deployment programs or are subject to portfolio requirements.¹⁵

Accordingly, entities ranging from generation owners to state agencies to even non-profits could be subject to an overarching regulatory scheme to achieve the applicable CO₂ performance goal. In the words of EPA:

¹³ See *id.*, at 11-12.

¹⁴ See *id.*, at 9.

¹⁵ See *id.*, at 10.

One likely state plan scenario involves inclusion of enforceable obligations for state-regulated entities other than affected EGUs. An example of a state-regulated entity that is not an owner or operator of affected EGUs may be an electric distribution utility. These entities are typically regulated by a state public utility commission. An example of an enforceable state plan measure that might apply to an electric distribution utility is a compliance obligation under a state end-use energy efficiency resource standard (EERS) or renewable portfolio standard (RPS), or implementation of incentive programs for the deployment of end-use energy efficiency and renewable energy technologies.¹⁶

The new regulatory architecture needed in restructured states, as outlined above by EPA itself, is tantamount to the "re-regulation" of electricity in these states.

7. Could states implement a multi-state plan under the Carbon Plan without approval from both state legislatures and Congress?

As discussed, I believe state legislation is required in all states, whether the state pursues an individual Section 111(d) state plan or a multi-state Section 111(d) plan. The necessary regulatory institutions and authorities simply do not exist. With regard to Congressional approval, the U.S. Constitution expressly addresses what amounts to contracts between individual states. Article I, section 10, clause 3 of the U.S. Constitution provides that "[n]o State shall, without the consent of Congress ... enter into any Agreement or Compact with another State." Interstate compacts can create enforceable obligations between parties, and the U.S. Supreme Court has held for nearly 200 years that compacts are contracts between individual states. The multi-state enforcement issues described in my responses to Questions 2(a)-(b) lead to the conclusion that a contract, in the form of an interstate compact, would be necessary to implement an enforceable multi-state Section 111(d) plan that allows states to enforce rights against one another to achieve compliance with the multi-state CO₂ performance goal.

Congressional approval is required for some but not all interstate compacts. Section VI of the white paper I co-authored (and submitted into the record along with my testimony) analyzes the issue of whether Congressional approval is necessary where states enter into an interstate compact. I believe it is very likely that a multi-state Section 111(d) plan with an interstate enforcement mechanism requires Congressional approval, and I am even more certain that if a group of states tries to proceed without such approval the states will be subject to protracted and expensive litigation.

8. The Federal Power Act has long prevented the federal government from interfering with state management of intrastate electricity matters. Yet, under the proposed Carbon Plan, EPA would have to approve how states operate their respective electricity systems.
- a. This proposal overturns nearly a century of state flexibility on electricity matters—is EPA's plan really providing "flexibility" for states?

¹⁶ See *id.*, at 14.

No. In my view, “flexibility” is a talking point to mask what the proposed CO₂ Emission Guidelines actually are, i.e., a top-down mandate to implement a federal energy policy that has not and could not garner Congressional approval. This is troubling as an overall matter of democratic governance. Moreover, EPA’s intrusion into state power over the electricity system raises substantial constitutional issues under the Tenth Amendment’s reservation of local regulatory powers to the states.

From a Clean Air Act perspective, the proposed CO₂ Emission Guidelines obviate the state primacy inherent in Section 111(d) and the principle of cooperative federalism. The Oklahoma Attorney General’s Plan, authored by Oklahoma Attorney General Scott Pruitt, concisely and properly construes Section 111(d):

EPA designs a procedure and emission guidelines, and States determine the legally enforceable emission standard that is as stringent as the applicable guideline – unless the State determines that circumstances justify imposition of a less stringent emission standard after evaluating the factors set forth at 40 C.F.R. § 60.24(f). More simply, the standard must satisfy the guideline unless enumerated circumstances, in the States’ estimation, exist. This invokes the principle of cooperative federalism, with roles clearly delineated for both EPA and the States.¹⁷

The proposed CO₂ Emission Guidelines do not comport with the statute or federal implementing regulations. EPA has provided no allowance for states to have a role in setting the carbon standard. The proposed rule states that Section 111(d) state plans or SIPs must achieve “emission performance equivalent to the goals established by the EPA, on a timeline equivalent to that” in the rule.¹⁸ The proposed rule offers no flexibility for a less-stringent standard or longer compliance timeline based on such factors as cost, reliability, or effect on ratepayers or the economy. EPA clearly rejected the case-by-case exceptions described in the federal implementing guidelines (40 C.F.R. § 60.24(f)) in its proposed rule:

The EPA therefore proposes that the remaining useful life of affected EGUs, and the other facility-specific factors identified in the existing implementing regulations, should not be considered as a basis for adjusting a state emission performance goal or for relieving a state of its obligation to develop and submit an approvable plan that achieves that goal on time.¹⁹

Further, the proposed rule does not allow deviation from carbon reduction mandate by analyzing what is achievable inside the fence, i.e., at the source. EPA’s “flexibility” refrain is an attempt to ignore this fundamental legal issue and reframe the discussion.

- b. The Federal Power Act restricts FERC authority to interstate electricity transmission and wholesale electricity prices, and leaves electricity generation and intrastate distribution to the States. Yet the proposed Carbon Plan short-circuits

¹⁷ E. Scott Pruitt, Attorney General, State of Oklahoma, *The Oklahoma Attorney General’s Plan: The Clean Air Act Section 111(d) Framework that Preserves States Rights*, at 2 (April 2014), available at http://documents.nam.org/ERP/OK_AG_Pruitt_Plan_05_20_14.pdf.

¹⁸ 79 Fed. Reg. at 34,838.

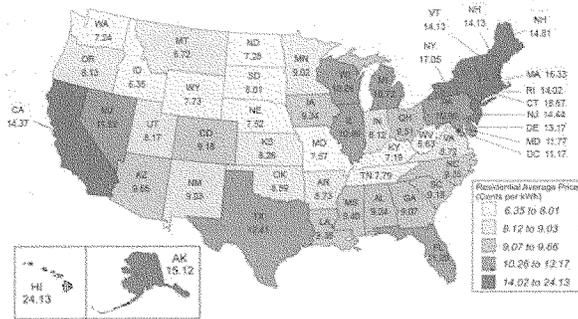
¹⁹ 79 Fed. Reg. at 34,926.

this separation, and places EPA in control of intrastate electricity matters. Under what legal authority is EPA claiming authority over the grid that Congress didn't even give to FERC?

There is no such legal authority. EPA's proposal ignores Congress's clear bright line between state and federal jurisdiction over the electricity system. No federal agency has authority to impose the building block assumptions, e.g., environmental dispatch and demand reduction, that EPA used to set each state's carbon cap in its CO₂ Emission Guidelines. EPA's proposed de facto federal energy policy, and with it regulation of every element of the U.S. economy that impacts the generation, transmission, distribution and consumption of the electricity, eviscerates the regulatory compact that has been a foundation of utility regulation for over 100 years.

EPA's CO₂ Rule and 18 States' Resolutions and Legislation

EPA's Proposed CO₂ Rule Collides with Flexibility Asserted By States



August 2014

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Executive Summary

18 state legislatures passed either legislation or resolutions that EPA has rejected in its CO₂ Emission Guidelines. The states demanded that the EPA respect state primacy in setting performance standards under Section 111(d) and/or allow the state maximum flexibility to implement carbon standards, including allowing a more lenient standard and schedule based on the state's unique circumstances or cost or reliability factors.

EPA's CO₂ Emission Guidelines sets firm carbon reduction standards that must be met by each state beginning in 2020 and accelerating through 2030, and excludes "case by case" exceptions based on factors discussed in federal implementing regulations. These factors include: (1) unreasonable costs of control resulting from plant age, location, or basic process design; (2) the physical impossibility of installing necessary control equipment; or (3) other factors that make application of a less stringent standard or final compliance time significantly more reasonable.

The EPA CO₂ Emission Guidelines do not allow states to set their own carbon performance standards. This ignores the fact that states believe they have primacy pursuant to Section 111(d) in determining what standards should apply based on unique state circumstances.

According to EPA Administrator McCarthy, unless a state can show that EPA's data related to its four building block approach is flawed, EPA will not entertain a less stringent carbon reduction target. However, the state-specific data provided in EPA's proposed rule relates to meeting the carbon reduction standard, not cost or reliability. This does not afford states the opportunity to request EPA consideration of a less stringent standard based on cost or reliability factors.

The majority of states enacting resolutions or legislation regarding Section 111(d) would limit the carbon reduction standard to what is reasonably achievable inside the fence, i.e., at the EGU source. However, three of EPA's four building blocks reside outside the fence, and EPA's CO₂ Emission Guidelines do not allow for a state to deviate from its carbon reduction mandate by analyzing what is achievable at the source.

States have directed their environmental agencies to consider less stringent carbon reduction standards and compliance schedules based on cost; effect on electric rates, jobs, low-income populations, and the economy; effect on reliability of the system; engineering considerations; and other factors unique to the state. Based on language in the CO₂ Emission Guidelines, it does not appear that EPA will entertain variance requests that are based on any of these factors.

States that passed resolutions or legislation inconsistent with the EPA's CO₂ Emission Guidelines will not be able to comply with both legislatively-expressed declarations and EPA's mandate. EPA will either choose to revise its proposed rule to respect the rights asserted by the states, or reject these state assertions and invite litigation. States are then left in the impossible dilemma of ignoring state law to follow EPA's prescribed mandate, which would, by definition, be an illegal act by a state agency.

I. Introduction

In our earlier White Paper, "State Implementation of CO₂ Rules," we discussed the significant institutional hurdles faced by states in implementing EPA's proposed rule to regulate carbon dioxide emissions (CO₂ Emission Guidelines) from electric generating units (EGUs). Briefly, we concluded:

- States will need to pass legislation to make it possible for state air regulators and utility regulators to implement the rule;
- Traditional non-state jurisdictional utilities will need to be made part of a unified "Carbon Integrated Resource Planning" (IRP) process;
- States pursuing a multi-state solution will need to enter into an Interstate Compact to make the rule enforceable, which will likely require congressional approval.

That White Paper of necessity elided some of the more nuanced state institutional questions embedded in the rule. Here, then, we embark on a follow-on series to explore some of those specific state issues.

The Opening Question for this Paper is:

How can states that have passed legislation or resolutions detailing how they will approach rule implementation "inside the fence" – and according to individual state policies, energy needs, resource mixes, and economic priorities – deal with EPA's proposed rule?

II. State Versus EPA-Defined "Flexibility"

On June 2, 2014, EPA issued its CO₂ Emission Guidelines under 42 U.S.C. § 7411(d) of the Clean Air Act (CAA) (Section 111(d)). Before that date, 18 state legislatures passed either legislation or resolutions¹ addressing the anticipated CO₂ Emission Guidelines. In virtually every case the legislatures requested or insisted that EPA respect state primacy in setting performance standards under Section 111(d), or allow

¹ As set forth below, five state legislatures passed bills that were signed by the governor, and thirteen state legislatures passed resolutions. Eight of these resolutions were passed by both the house and senate chambers, and five were passed by one of the two chambers.

the state maximum flexibility to implement carbon standards, including allowing a more lenient standard and schedule based on the state's unique circumstances, cost or reliability factors.

EPA effectively rejected these state requests and the notion of state primacy in its proposed CO₂ Emission Guidelines. The Guidelines set firm carbon reduction standards that must be met by each state beginning in 2020 and accelerating through 2030. The Guidelines also obviate the states' ability, promulgated in the Section 111(d) implementing regulations, to seek "case-by-case" exceptions (also called "variances") based on factors such as: (1) unreasonable costs of control resulting from plant age, location, or basic process design; (2) the physical impossibility of installing necessary control equipment; or (3) other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable. Finally, EPA's proposed rule rejects the possibility of a less stringent standard or final compliance time.² Instead, the proposed rule requires that state Section 111(d) plans show "achievement of emission performance equivalent to the goals established by the EPA, on a timeline equivalent to that in the emission guidelines."

It is unclear whether EPA will revise its final rule to allow for these exceptions, or more lenient carbon reduction standards or compliance time. Initial signals from the agency are not promising. Robert Kenney, Chair of the Missouri Public Service Commission, asked the following question of EPA Administrator Gina McCarthy at the National Association of Regulatory Utility Commissioners (NARUC) Conference in Dallas on July 14, 2014: "If a state does its own modeling and determines that it can't reach the target at a reasonable cost, will the EPA entertain a less stringent target that is proposed by a state?" Administrator McCarthy's response in full is as follows (emphasis supplied):

Well I think that what we did was, we tried to identify what we thought was reasonable and appropriate and get it one way, but allow the states every flexibility to get it in more creative ways. And by doing that we think we met the underlying requirements in the statute *so there wouldn't be a*

² See EPA's CO₂ Emission Guidelines, at 520.

second opportunity to look at costs unless you think we blew the first analysis. Okay, so it's really important, and I don't want to say this casually, it's really important to take a look at the underlying analysis for the states, take a look at it. Did we miss it, were the numbers not right? We've teed up a couple of alternatives which we're open to, because there's a lot here, and so take a look at it. There is two things to consider. One is, did we get this framing correct? But very importantly out of the gate is the data question. And so that's what led us to believe that we could do this in a way that was reliable and affordable, and the reliability and affordability of the electricity sector is not something that we're going to compromise. And so we don't think it's required, we think there's ways in which we can move forward and we've shown that. But if you see any problems with that data we really would like to see it soon and see if there's other things that we can consider.³

Administrator McCarthy's response strongly suggests that EPA will not entertain a less stringent target unless a state can show that EPA's data is flawed. Notably, the data provided by EPA in its proposed rule relates to the EPA's four "building blocks"⁴ as one approach to meet the carbon reduction standard. However, EPA did not attempt to estimate the cost impact to any individual state in its CO₂ Emission Guidelines. Accordingly, there can be no "second opportunity" for a state to request EPA review of costs because EPA has not analyzed state-by-state costs as part of its "first analysis." Thus, a state showing that electric rates will substantially increase as a result of complying with EPA's carbon reduction mandate cannot be a basis for a less stringent standard or compliance schedule under the proposed rule.

³ Remarks of EPA Administrator Gina McCarthy at NARUC Summer Conference in Dallas Texas, July 14, 2014. We believe our contemporaneous notes faithfully represent these remarks and Chairman Kenney's question of Administrator McCarthy.

⁴ EPA calculated the CO₂ performance goal using four "building blocks": (1) assuming a six percent heat-rate efficiency improvement to each existing coal-fired EGU; (2) assuming a 70 percent capacity utilization rate for combined-cycle gas-fired EGUs; (3) calculating a renewable portfolio standard (RPS) based on the average RPS of states in the same region of the country, and assuming usage of nuclear power plants based on existing and expected nuclear units; and (4) assuming a one and one-half percent per year reduction in electric usage through demand-side management (DSM) measures.

If a state's only basis to challenge the CO₂ Emission Guidelines is the EPA's data on the four building blocks approach to emission reduction, then factors other than cost likewise cannot provide a basis for a variance. Factors such as system reliability, physical possibility of installing necessary control equipment, or other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time more reasonable are excluded by EPA. Because EPA did not undertake unit-specific or state-specific analyses to determine whether meeting the carbon reduction standard will result in reliability or other problems, there is no data on these issues that a state can contest. The only issue for which the EPA provided state-specific data is whether a state can achieve the carbon reductions mandated in the proposed rule.

Even if a state can show flaws in the four building blocks data as applied to the state, it is not clear this would be sufficient to obtain a variance. Beyond EPA's denial of "case-by-case" exceptions, Administrator McCarthy stressed at the NARUC conference that the EPA's four building blocks approach is just "one way" to meet the standards. It is unknown whether a state would need to show that other possible "ways" of meeting the standard also are unworkable to obtain a variance. For example, if a state shows that the 70 percent gas combined cycle dispatch assumption (in Building Block 2) is not achievable because of, say, gas pipeline infrastructure, electric transmission constraints, or need for the gas capacity to load-follow intermittent resources, a state may still be able to achieve the carbon reduction mandate by shuttering a number of coal generation plants. It may be that states will have to prove impossibility of meeting the performance targets from any of the four pathways outlined in EPA's proposed rule⁵ before EPA would consider flexibility.

We conclude that, while EPA's CO₂ Emission Guidelines may provide "flexibility" on the issue of how a state goes about meeting its carbon reduction mandate, the Guidelines do not allow for a less

⁵ In its State Plan Considerations Technical Support Document, EPA proposes four "state plan pathways": (1) rate-based CO₂ emission limits; (2) mass-based CO₂ emission limits; (3) a state-driven portfolio approach; and (4) a utility-driven portfolio approach. The EPA's four building blocks suggestion is one portfolio approach, which includes "emission limits for affected EGUs along with other enforceable end-use energy efficiency and renewable energy measures that avoid EGU CO₂ emissions."

stringent carbon reduction standard or compliance schedule based on a state showing of expected increase in electric rates, system reliability issues, physical impossibility of installing controls, or other factors based on a state's unique circumstances.

The state institutional dilemma arises because EPA's proposed rule contravenes the legislatively expressed expectations of 18 states for state primacy and EPA flexibility, as well as the Section 111(d) implementing regulations.

Accordingly, states with resolutions or legislation inconsistent with the EPA mandates will be placed in a very difficult position. State environmental agencies must follow state statute, and arguably should follow the language of legislatively-passed resolutions. To the extent they do so and their actions are inconsistent with the CO₂ Emission Guidelines, EPA will either choose to revise its proposed rule to respect the rights asserted by the states, or reject these state assertions. If EPA takes the latter course, then it may be impossible for states to comply with both the EPA CO₂ Emission Guidelines and the directives of their legislatures.

III. Legislation and Resolutions of 18 States

The following state legislatures passed either legislation or a resolution consistent with their reasonable expectation that the EPA CO₂ Emission Guidelines will preserve state rights and flexibility under Section 111(d) of the CAA:

Legislation

1. Kansas – House Bill 2636
2. Kentucky – House Bill 338
3. Louisiana – Act 726
4. Missouri – House Bill 1631
5. West Virginia – House Bill 6346⁶

⁶ Notably, the Ohio State House unanimously passed House Bill 506, although it was not passed by the Ohio State Senate. Ohio State House Bill 506 is similar to the legislation passed in Kansas, Kentucky, and West Virginia.

Resolutions⁷

6. Alabama – Joint Resolution 57
7. Arkansas - Senate Resolution 2*
8. Arizona – Concurrent Resolution 1022
9. Florida – SM 1174
10. Georgia – House Resolution 1158
11. Illinois - House Resolution 0782*
12. Indiana - House Resolution 11*
13. Nebraska - Legislative Resolution 482
14. Oklahoma - Concurrent Resolution 39
15. Pennsylvania - House Resolution 815*
16. South Dakota - Concurrent Resolution 1022
17. Tennessee - House Joint Resolution 663*
18. Wyoming – Senate Joint Resolution 1

* Not Concurrent with other chamber

Consistent themes emerge from these legislative pronouncements. The overwhelming majority of these 18 states demand that the EPA respect state primacy in setting CO₂ performance standards, look at the individual circumstances of each state, and allow more lenient carbon reduction performance based on cost and other considerations. Many states also limit the carbon reduction goal to measures achievable "inside the fence" (*i.e.*, at the EGU source), disallow fuel switching at the EGU to meet the goal, require that any assumed technology to meet the goal be commercially demonstrated, and apply separate standards for coal and gas generation units. As explained below, it appears that virtually all of these expectations have been rejected in EPA's proposed CO₂ Emission Guidelines.

A. State Primacy

The states that passed resolutions and legislation concerning Section 111(d) assert primacy in

⁷ To be sure, a Resolution is hortatory, not mandatory, like a law. Nevertheless, a state agency has some obligation to follow the policy direction set by the legislature.

determining what legally-enforceable carbon performance standards apply in each respective state. This is consistent with the plain language of the federal Section 111(d) implementing regulations. For example, Alabama Joint Resolution 57 states that the EPA "must maintain Alabama's and other states' authority as provided by the Clean Air Act, to rely on state regulators to develop performance standards for carbon dioxide emissions that take into account the unique policies, energy needs, resource mix, and economic priorities of Alabama and other states." Florida also urged EPA to "respect the primacy of Florida and rely on state regulators to develop performance standards for carbon dioxide emissions" that take into account Florida's unique policies, needs and priorities. Resolutions passed in Illinois, Indiana, Nebraska, Oklahoma, Pennsylvania, South Dakota, Tennessee, West Virginia, and Wyoming contain nearly identical language.

Similarly, Georgia and Kentucky found that "Congress charges the states, not EPA, with establishing standards of performance under [Section 111(d)] of the federal Clean Air Act." The State of Arkansas "urges EPA to withdraw the proposed guidelines for reducing carbon dioxide emissions from fossil fuel-fired power plants under [Section] 111(d) of the Clean Air Act and propose new guidelines that respect the primacy of the State of Arkansas to determine the emission reduction requirements that are in the best interest of its citizens." The remainder of the 18 states either explicitly or implicitly presume that their state agencies, not the EPA, will set the applicable carbon reduction standard.

As described above, EPA's CO₂ Emission Guidelines reject the notion that states have any authority in setting the carbon emission standard. Instead, EPA has set the numeric carbon emission pounds per Megawatt hour limit for each state from 2020 through 2030. EPA's proposed rule further provides that the agency will evaluate and approve state plans based on four general criteria: 1) enforceable measures that reduce EGU CO₂ emissions; 2) projected achievement of emission performance equivalent to the goals established by the EPA, on a timeline equivalent to that in the emission guidelines; 3) quantifiable and verifiable emission reductions; and 4) a process for biennial reporting on plan implementation, progress toward achieving CO₂ goals, and implementation of corrective actions, if necessary.⁸

⁸ CO₂ Emission Guidelines at 46 (emphasis supplied).

No latitude is provided for states to either set their own carbon reduction standard or deviate from the goals established by EPA.

B. Inside the Fence

The majority of states that passed a resolution or legislation regarding Section 111(d) would limit the carbon reduction standard to what is reasonably achievable inside the fence, *i.e.*, at the EGU source. For example, Alabama, Florida, Illinois, Indiana, Nebraska, Oklahoma, Pennsylvania, South Dakota, Tennessee, West Virginia, and Wyoming passed resolutions that convey that EPA should "approve state-established performance standards that are based on reductions of carbon dioxide emissions determined to be achievable by measures undertaken *at fossil-fueled electric generating units*," or language to the same effect.

Similarly, Louisiana and Missouri passed legislation directing their state environmental agencies to set the standard of performance based on reductions in emissions of carbon dioxide that can reasonably be achieved through measures undertaken *at each fossil fuel-fired electric generating unit*, including efficiency improvements. In each case the legislation allows utilities and EGUs to *implement* the standard through outside the fence measures, but the *setting* of the standard may only consider what is achievable inside the fence.

Three of EPA's four building blocks reside outside the fence. Perhaps recognizing that inside the fence measures are insufficient to meet EPA's 30 percent carbon reduction goal by 2030, only one building block assumption -- average heat rate improvement of six percent for coal-fired EGUs -- is source-focused. Building blocks 2, 3 and 4 of the CO₂ Emission Guidelines assume that utilities can meet certain outside the fence metrics. Although the proposed rule does not require states and utilities to actually implement these metrics, they are the root of each state's CO₂ performance goal.

The EPA's CO₂ Emission Guidelines do not allow for a state to deviate from its carbon reduction mandate by analyzing what is achievable at the source. EPA has assumed that greater carbon reductions may be achieved by looking outside the fence, so states must presumably employ these tools.

EPA has effectively rejected state resolutions and legislation that would afford the states flexibility to focus their carbon reduction efforts on what is reasonably achievable at the source. Whether EPA may lawfully force states to look at outside the fence measures or essentially require the closure or fuel switching of EGUs is in serious question given the focus on source-based emissions and state primacy in Section 111(d) of the CAA.

C. Variance Flexibility

Every state that passed resolutions or legislation requested that EPA grant "maximum flexibility" for states to set carbon reductions standards, implement the standards, or both.

The substantial majority of states passing legislation or resolutions express the right to an emissions reduction variance based on factors of cost, physical possibility, effect on local economy, and other factors unique to the state. These factors are based on the federal implementing guidelines, 40 C.F.R. § 60.24(f), which provides that states may make a case-by-case determination that a specific facility or class of facilities are subject to a less-stringent standard or longer compliance schedule due to: (1) cost of control; (2) a physical limitation of installing necessary control equipment; and (3) other factors making the less-stringent standard more reasonable.

However, EPA has rejected the possibility of granting a variance based on any of these factors. The CO₂ Emission Guidelines state at page 520 as follows:

The EPA therefore proposes that the remaining useful life of affected EGUs, and the other facility-specific factors identified in the existing implementing regulations, should not be considered as a basis for adjusting a state emission performance goal or for relieving a state of its obligation to develop and submit an approvable plan that achieves that goal on time.

Whether EPA may lawfully dismiss this implementing regulation is beyond the scope of this paper.

The state-passed resolutions and legislation assert a right to a variance. For example, the resolutions passed by Florida, Illinois, Indiana, Nebraska, Pennsylvania, South Dakota, Tennessee, and Wyoming would allow the state "to set less stringent performance standards or longer compliance schedules for fossil-fueled electric

generating units," or language to the same effect.

Kansas, Louisiana, and West Virginia passed statutes directing their state environmental departments to consider whether to adopt less stringent performance standards or longer compliance schedules for EGUs based on the following factors:

- (1) Consumer impacts including any disproportionate energy price increases on lower income populations;
- (2) Unreasonable costs of reducing emissions of carbon dioxide resulting from the age, location, or basic process design of the electric generating unit;
- (3) Physical difficulties with or the impossibility of implementing emission reduction measures for carbon dioxide;
- (4) The absolute cost of applying the performance standard to the electric generating unit;
- (5) The expected remaining useful life of the electric generating unit;
- (6) The economic impacts of closing the electric generating unit, including expected job losses, if the unit is unable to comply with the performance standard; and
- (7) Any other factors specific to the electric generating unit that make application of a less stringent performance standard or longer compliance schedule more reasonable.⁹

Apart from granting variances, several states list cost and reliability as factors that should be considered in the initial setting of the carbon emissions reduction standard. These states include the ones listed above, as well as Georgia, Kansas, and Kentucky.

⁹ West Virginia's statute adds the additional factors of: (1) Non-air quality health and environmental impacts; (2) Projected energy requirements; (3) Market-based considerations in achieving performance standards; and (4) Impacts on the reliability of the system. Missouri's statutory factors include the ones listed in the federal implementing guidelines, as well as (1) the absolute cost of applying the emission standard and compliance schedule to the existing affected source; (2) the outstanding debt associated with the existing affected source; (3) the economic impacts of closing the existing affected source, including expected job losses if the existing affected source is unable to comply with the performance standard; and (4) the customer impacts of applying the emission standard and compliance schedule to the existing affected source, including any disproportionate electric rate impacts on low income populations.

State laws direct their environmental agencies to consider less-stringent carbon reduction standards and compliance schedules based on such factors as cost; effect on electric rates, jobs, low-income populations, and the economy; effect on reliability of the system; engineering considerations; and other factors unique to the state. The EPA appears to have foreclosed the possibility of considering these factors in its proposed rule.

D. Other Factors

States have asserted several other rights associated with Section 111(d) of the CAA, including disallowing fuel switching (e.g., from coal to gas), co-firing with other fuels, or decreased unit utilization as bases to meet carbon reduction standards (Kansas, Kentucky, Louisiana, West Virginia); precluding the assumption of technology that is not adequately demonstrated as a basis for carbon reduction (Georgia, Kansas, Kentucky, Louisiana, West Virginia); and the right to set carbon reduction standards separately for coal and gas-fired EGUs (Kansas, Kentucky, West Virginia).

In sum, the states' views and the EPA's proposed rule essentially talk past one another. The states assert rights and direct their agencies how to approach analysis under 111(d), and the EPA proposal expects a State Implementation Plan (SIP) that goes beyond those boundaries expressed in state law.

This gives rise to the question of what rights a state has if the four building block assumptions prove to be inaccurate or impractical for the state. If a state cannot reasonably achieve the mandated carbon reduction through increased renewable energy, demand side load reduction, increased utilization of gas-fired combined cycle units, and heat rate improvements to coal EGUs, it may need to look at the very measures precluded by legislation, such as fuel switching, decreased utilization of certain EGUs, and attempting to use technology that has not been adequately demonstrated. EPA's rejection of legislatively-passed declarations and statutes places states agencies tasked with implementing the rules in a very difficult position.

IV. State Agencies Bound to Follow State Law

Given the state resolutions and legislation discussed above, state agencies may find themselves in the unenviable position of not being able to follow both the EPA mandate and state legislative pronouncements. In such a case, state agencies are bound to follow

applicable state legislation.¹⁰

Put another way, a state agency cannot conduct a preemption analysis and declare that a state law directing how the agency should perform its Section 111(d) determination must give way to a rule promulgated by EPA. State environmental agencies may not, for example, ignore statutory commands to set carbon reduction standards based on what is reasonably achievable in light of cost, reliability, and engineering considerations.

The state statutes that have been rejected by EPA control the state agencies that will conduct Section 111(d) proceedings. The eight resolutions passed by state legislatures (and five by one chamber of state legislatures) indicate that many states may pass new legislation in 2015 or 2016 that likewise collide with EPA's proposed rule. Two conclusions follow: (1) courts will likely decide which regulations are more consistent with the CAA, the state statute or EPA's proposed rule; and (2) EPA will either back down and respect state pronouncements, or subject these states to a federal implementation plan, or FIP. The latter choice also calls for court resolution.

V. Initial Conclusions and Takeaways

We offer these tentative conclusions and takeaways based upon the above analysis and discussion:

- 18 state legislatures passed either legislation or resolutions that EPA has rejected in its CO₂ Emission Guidelines.
- EPA's CO₂ Emission Guidelines sets firm carbon reduction standards that must be met by each state beginning in 2020 and accelerating through 2030, and denies "case by case" exceptions based on factors discussed in federal implementing regulations.

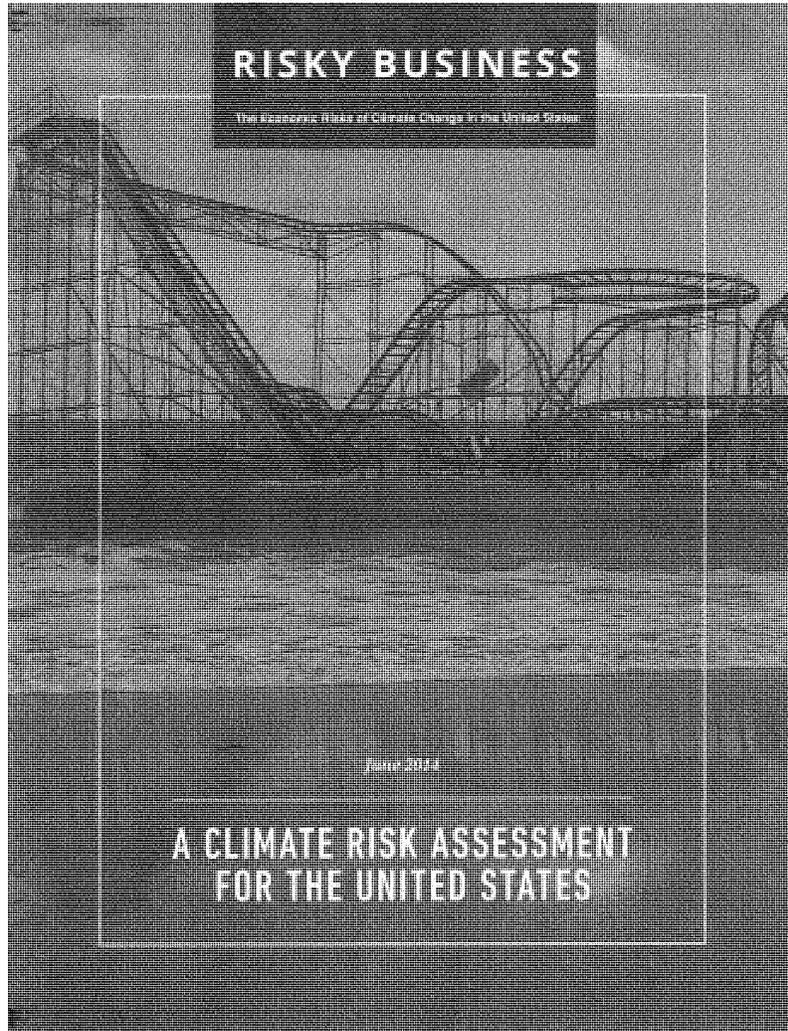
¹⁰ Some may argue that the state statutes discussed in this Paper create an impermissible obstacle that frustrates the federal purpose of the CAA and EPA's CO₂ Emission Guidelines. We see no such conflict. The state laws direct the appropriate state regulator to conduct specific analyses in formulating legally enforceable emission standards – a right explicitly reserved to the states under Section 111(d) and its federal implementing regulations. These state laws do not attempt to frustrate the federal purpose of the proposed CO₂ Emission Guidelines or put in place an impermissible obstacle to its implementation. Rather, they exert state primacy and the rights left to the states under Section 111(d).

- The EPA CO₂ Emission Guidelines do not allow states to set their own carbon performance standards, notwithstanding the fact that states believe they have primacy pursuant to Section 111(d) in determining what standards should apply based on unique state circumstances.
- According to EPA Administrator McCarthy, unless a state can show that EPA's data related to its four building block approach is flawed, EPA will not entertain a less stringent carbon reduction target. However, the state-specific data provided in EPA's proposed rule relates to meeting the carbon reduction standard, not cost or reliability. This does not afford states the opportunity to request EPA consideration of a less stringent standard based on cost or reliability factors.
- The majority of states enacting resolutions or legislation regarding Section 111(d) would limit the carbon reduction standard to what is reasonably achievable inside the fence, *i.e.*, at the EGU source. However, EPA's CO₂ Emission Guidelines do not allow for a state to deviate from its carbon reduction mandate by analyzing what is achievable at the source.
- States have directed their environmental agencies to consider less stringent carbon reduction standards and compliance schedules based on cost; effect on electric rates, jobs, low-income populations, and the economy; effect on reliability of the system; engineering considerations; and other factors unique to the state. It does not appear that EPA will entertain variance requests that are based on any of these factors.
- States with resolutions/legislation inconsistent with the CO₂ Emission Guidelines will not be able to comply with both legislatively-expressed declarations and EPA's mandate. EPA will either choose to revise its proposed rule to respect the rights asserted by the states, or reject these state assertions and invite litigation. States are then left in the impossible dilemma of ignoring state law to follow EPA's prescribed mandate, which would, by definition, be an illegal act by a state agency.

Appendix II

ADDITIONAL MATERIAL FOR THE RECORD

REPORT SUBMITTED BY RANKING MEMBER EDDIE BERNICE JOHNSON



RISKY BUSINESS: The Economic Risks of Climate Change in the United States

A Product of the Risky Business Project:

Co-Chairs:

Michael R. Bloomberg, founder, Bloomberg Philanthropies; 108th Mayor of the City of New York; founder, Bloomberg L.P.

Henry M. Paulson, Jr., Chairman of the Paulson Institute; former U.S. Secretary of the Treasury

Thomas F. Steyer, retired founder, Farallon Capital Management LLC

Risk Committee Members:

Henry Cisneros, Founder and Chairman, CityView Capital; former U.S. Secretary of Housing and Urban Development (HUD); former Mayor of San Antonio

Gregory Page, Executive Chairman, Cargill, Inc. and former Cargill Chief Executive Officer

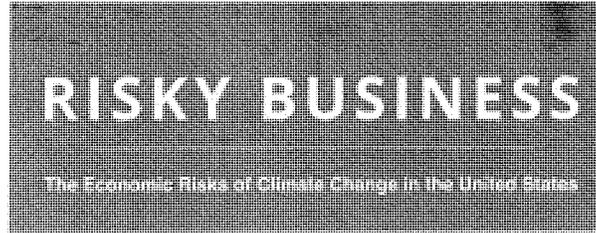
Robert E. Rubin, Co-Chairman, Council on Foreign Relations; former U.S. Secretary of the Treasury

George P. Shultz, Thomas W. and Susan B. Ford Distinguished Fellow at the Hoover Institution; former U.S. Secretary of State; former U.S. Secretary of the Treasury; former U.S. Secretary of Labor; former Director, Office of Management and Budget; former President, Bechtel Group

Donna E. Shalala, President, University of Miami; former U.S. Secretary of Health and Human Services

Olympia Snowe, former U.S. Senator representing Maine

Dr. Alfred Sommer, Dean Emeritus, Bloomberg School of Public Health; University Distinguished Service Professor, Johns Hopkins University



June 2014

**A CLIMATE RISK ASSESSMENT
FOR THE UNITED STATES**

ACKNOWLEDGEMENTS

Lead Authors Kate Gordon, Executive Director of the Risky Business Project, drawing from independent research commissioned by the Risky Business Project. Special thanks to Matt Lewis, Risky Business Project **Communications Director**, and Jamesine Rogers, Risky Business Project Manager, for their editorial support.

Research Risky Business Project co-chairs Michael R. Bloomberg, Henry Paulson, and Tom Steyer tasked the Rhodium Group, an economic research firm that specializes in analyzing disruptive global trends, with an independent assessment of the economic risks posed by a changing climate in the U.S. Rhodium convened a research team co-led by Dr. Robert Kopp of Rutgers University and economist Dr. Solomon Hsiang of the University of California, Berkeley. Rhodium also partnered with Risk Management Solutions (RMS), the world's largest catastrophe-modeling company for insurance, reinsurance, and investment-management companies around the world. The team leveraged recent advances in climate modeling, econometric research, private sector

risk assessment, and scalable cloud computing (processing over 20 terabytes of climate and economic data) to provide decision-makers with empirically-grounded and spatially-explicit information about the climate risks they face. The team's complete assessment, along with technical appendices, is available at Rhodium's website, climateprospectus.rhg.com. Interactive maps and other content associated with the Risky Business Project are located at riskybusiness.org.

The research team's work was reviewed by an independent Risky Business Expert Review Panel composed of leading climate scientists and economists. A full list of the expert review panel is available on Rhodium's website.

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PLEASE NOTE: Several numbers in this report were updated on July 18, 2014 to reflect the most current data from the American Climate Prospectus.

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CLIMATE RISK ASSESSMENT | THE CLIMATE RISK ASSESSMENT TOOLKIT FOR FINANCIAL INSTITUTIONS



Damages from storms, flooding, and heat waves are already costing local economies billions of dollars—we saw that firsthand in New York City with Hurricane Sandy. With the oceans rising and the climate changing, the Risky Business report details the costs of inaction in ways that are easy to understand in dollars and cents—and impossible to ignore.

— Risky Business Project Co-Chair Michael R. Bloomberg¹

The U.S. faces significant and diverse economic risks from climate change. The signature effects of human-induced climate change—rising seas, increased damage from storm surge, more frequent bouts of extreme heat—all have specific, measurable impacts on our nation's current assets and ongoing economic activity.

To date, there has been no comprehensive assessment of the economic risks our nation faces from the changing climate. *Risky Business: The Economic Risks of Climate Change to the United States* uses a standard risk-assessment approach to determine the range of potential consequences for each region of the U.S.—as well as for selected sectors of the economy—if we continue on our

current path. The Risky Business research focused on the clearest and most economically significant of these risks: **Damage to coastal property and infrastructure from rising sea levels and increased storm surge, climate-driven changes in agricultural production and energy demand, and the impact of higher temperatures on labor productivity and public health.**

Our research combines peer-reviewed climate science projections through the year 2100 with empirically-derived estimates of the impact of projected changes in temperature, precipitation, sea levels, and storm activity on the U.S. economy. We analyze not only those outcomes most likely to occur, but also lower-probability

EXECUTIVE SUMMARY

high-cost climate futures. Unlike any other study to date, we also provide geographic granularity for the impacts we quantify, in some cases providing county-level results.

Our findings show that, if we continue on our current path, many regions of the U.S. face the prospect of serious economic effects from climate change. However, if we choose a different path—if we act aggressively to both adapt to the changing climate and to mitigate future impacts by reducing carbon emissions—we can significantly reduce our exposure to the worst economic risks from climate change, and also demonstrate global leadership on climate.

Climate Change: Nature's Interest-Only Loan

Our research focuses on climate impacts from today out to the year 2100, which may seem far off to many investors and policymakers. But climate impacts are unusual in that future risks are directly tied to present decisions. Carbon dioxide and other greenhouse gases can stay in the atmosphere for hundreds or even thousands of years. Higher concentrations of these gases create a "greenhouse effect" and lead to higher temperatures, higher sea levels, and shifts in global weather patterns. The effects are cumulative: By not acting to lower

SHORT-TERM CLIMATE THREATS

The American economy is already beginning to feel the effects of climate change. These impacts will likely grow substantially over the next 10 to 20 years and affect the future performance of some's business and investment decisions in the following areas:

Coastal property and infrastructure. Within the next 20 years, higher sea levels combined with coastal surge will likely inundate the average coastal residential estate along the Eastern Seaboard and the Gulf of Mexico by 60 to 100 to 150 million. Adding in potential changes in hurricane activity, the likely increase in average annual flood losses to up to \$1.6 billion, bringing the total annual risk to the coastal sector and other economic sectors to \$20 billion.

Agriculture. A striking adverse impact of agriculture in the U.S. is its ability to adapt. For the agriculture

challenge going through the world to crops in specific regions in the Midwest and South will be significant. Wheat, corn, soybeans, sorghum, and other crops will likely see a decline in yields of more than 50% over the next 20 years unless they continue to see cost, yield, and water yields a 10% to 20% of total income of those crops or more than 20%.

Energy. Greenhouse gas-driven changes in temperature will likely decrease the contribution of gas to the generation of new power generation capacity over the next 20 to 25 years—the equivalent of around 200,000 MW of capacity. This will mean some of the most important and competitive categories up to \$10 billion per year.

EXECUTIVE SUMMARY

greenhouse gas emissions today, decision-makers put in place processes that increase overall risks tomorrow, and each year those decision-makers fail to act serves to broaden and deepen those risks. In some ways, climate change is like an interest-only loan we are putting on the backs of future generations: They will be stuck paying off the cumulative interest on the greenhouse gas emissions we're putting into the atmosphere now, with no possibility of actually paying down that "emissions principal."

Our key findings underscore the reality that if we stay on our current emissions path, our climate risks will multiply and accumulate as the decades tick by. These risks include:

- **Large-scale losses of coastal property and infrastructure**

- » If we continue on our current path, by 2050 between \$66 billion and \$106 billion worth of existing coastal property will likely be below sea level nationwide, with \$238 billion to \$507 billion worth of property below sea level by 2100.
- » There is a 1-in-20 chance—about the same chance as an American developing colon cancer; twice as likely as an American developing melanoma²—that by the end of this century, more than \$701 billion worth of existing coastal property will be below mean sea levels, with more than \$730 billion of additional property at risk during high tide. By the same measure of probability, average annual losses from hurricanes and other coastal storms along the Eastern Seaboard and the Gulf of Mexico will grow by more than \$42 billion due to sea level rise alone. Potential changes in hurricane activity could raise this figure to \$108 billion.

- » Property losses from sea level rise are concentrated in specific regions of the U.S., especially on the Southeast and Atlantic coasts, where the rise is higher and the losses far greater than the national average.

- **Extreme heat across the nation—especially in the Southwest, Southeast, and Upper Midwest—threatening labor productivity, human health, and energy systems**

- » By the middle of this century, the average American will likely see 27 to 50 days over 95°F each year—two to more than three times the average annual number of 95°F days we've seen over the past 30 years. By the end of this century, this number will likely reach 45 to 96 days over 95°F each year on average.
- » As with sea level rise, these national averages mask regional extremes, especially in the Southwest, Southeast, and upper Midwest, which will likely see several months of 95°F days each year.
- » Labor productivity of outdoor workers, such as those working in construction, utility maintenance, landscaping, and agriculture, could be reduced by as much as 3%, particularly in the Southeast. For context, labor productivity across the entire U.S. labor force declined about 1.5% during the famous "productivity slowdown" in the 1970s.³
- » Over the longer term, during portions of the year, extreme heat could surpass the threshold at which the human body can no longer maintain a normal core temperature without air conditioning, which we measure using a "Humid Heat-Stroke Index" (HHSI). During these periods, anyone whose job requires them to work outdoors, as well as anyone lacking

EXECUTIVE SUMMARY

access to air conditioning, will face severe health risks and potential death.

- » Demand for electricity for air conditioning will surge in those parts of the country facing the most extreme temperature increases, straining regional generation and transmission capacity and driving up costs for consumers.
- **Shifting agricultural patterns and crop yields, with likely gains for Northern farmers offset by losses in the Midwest and South**
 - » As extreme heat spreads across the middle of the country by the end of the century, some states in the Southeast, lower Great Plains, and Midwest risk up to a 50% to 70% loss in average annual crop yields (corn, soy, cotton, and wheat), absent agricultural adaptation.
 - » At the same time, warmer temperatures and carbon fertilization may improve agricultural productivity and crop yields in the upper Great Plains and other northern states.
 - » Food systems are resilient at a national and global level, and agricultural producers have proven themselves extremely able to adapt to changing climate conditions. These shifts, however, still carry risks for the individual farming communities most vulnerable to projected climatic changes.

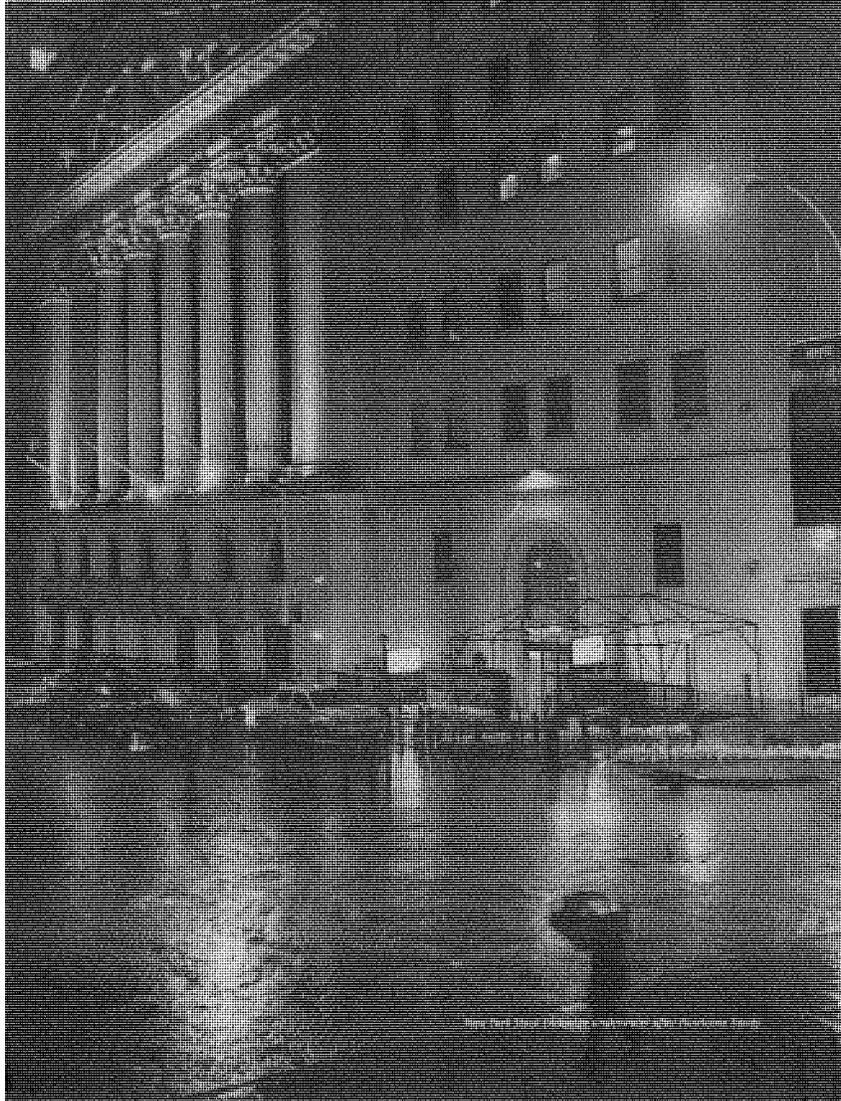
The Risky Business Project is designed to highlight climate risks to specific business sectors and regions of the economy, and to provide actionable data at a geographically granular level for decision-makers. It is our hope that it becomes standard practice for the American business and investment community to factor climate

change into its decision-making process. We are already seeing this response from the agricultural and national security sectors; we are starting to see it from the bond markets and utilities as well. But business still tends to respond only to the extent that these risks intersect with core short term financial and planning decisions.

We also know that the private sector does not operate in a vacuum, and that the economy runs most smoothly when government sets a consistent policy and a regulatory framework within which business has the freedom to operate. Right now, cities and businesses are scrambling to adapt to a changing climate without sufficient federal government support, resulting in a virtual “unfunded mandate by omission” to deal with climate at the local level.⁴ We believe that American businesses should play an active role in helping the public sector determine how best to react to the risks and costs posed by climate change, and how to set the rules that move the country forward in a new, more sustainable direction.

With this report, we call on the American business community to rise to the challenge and lead the way in helping reduce climate risks. We hope the Risky Business Project will facilitate this action by providing critical information about how climate change may affect key sectors and regions of our national economy.

This is only a first step, but it’s a step toward getting America on a new path leading to a more secure, more certain economic future.



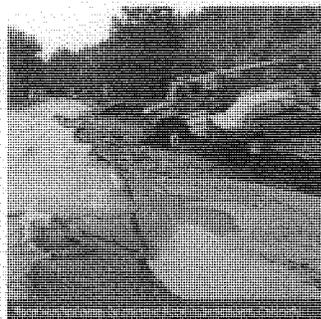
INTRODUCTION

Americans understand risk. Our ability to evaluate risk—to take calculated plunges into new ventures and economic directions and to innovate constantly to bring down those risks—has contributed immensely to the nation's preeminence in the global economy. From the private sector's pioneering venture-capital financing model to the government's willingness to invest in early-stage inventions like the computer chip or the solar panel, our nation's ability to identify and manage potential risks has moved the economy forward in exciting and profitable directions.

The Risky Business Project is designed to apply risk assessment to the critical issue of climate change, and to take a sober, fact-based look at the potential risks facing specific sectors and regions of the national economy. As in a classic business risk assessment, we analyzed not only the most likely scenarios, but also the scenarios that, while less likely, could have more significant impacts.

Our conclusion: The American economy faces multiple and significant risks from climate change. Climate conditions vary dramatically across the U.S., as does the mix of economic activity. Those variations will benefit our economic resilience to future climatic changes. But each region of the country has a different risk profile and a different ability to manage that risk. There is no single top-line number that represents the cost of climate change to the American economy as a whole: We must take a regional approach to fully understand our climate risk.

Given the range and extent of the climate risks the American economy faces, it is clear that staying on our current path will only increase our exposure. The U.S. climate is paying the price today for business decisions made many years ago, especially through increased coastal storm damage and more extreme heat in parts of the country. Every year that goes by without a comprehensive

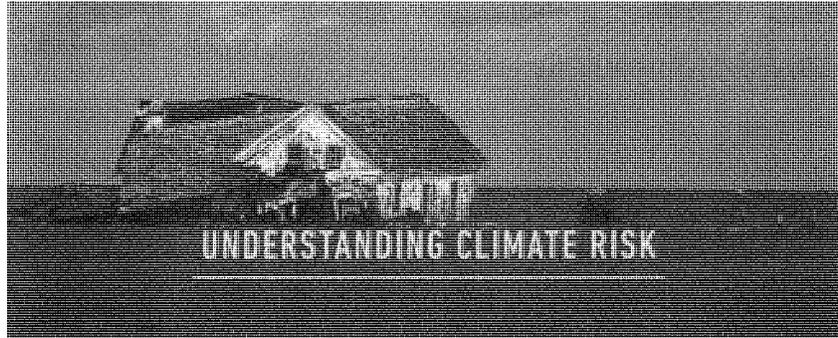


public and private sector response to climate change is a year that locks in future climate events that will have a far more devastating effect on our local, regional, and national economies. Moreover, both government and the private sector are making investment decisions today—whether in property, long-term infrastructure or regional and national supply chains—that will be directly affected by climate change in decades to come.

Our assessment finds that, if we act now, the U.S. can still avoid most of the worst impacts and significantly reduce the odds of costly climate outcomes—but only if we start changing our business and public policy practices today.

The Risky Business Project does not dictate the solutions to climate change; while we fully believe the U.S. can respond to these risks through climate preparedness and mitigation, we do not argue for a specific set or combination of these policies. Rather, we document the risks and leave it to decision-makers in the business and policy communities to determine their own tolerance for, and specific reactions to, those risks.





I know a lot about financial risks—in fact, I spent nearly my whole career managing risks and dealing with financial crisis. Today I see another type of crisis looming: A climate crisis. And while not financial in nature, it threatens our economy just the same.

— Risky Business Project Co-Chair Henry Paulson ⁵

In order to know how to best respond to climate change, we first need to fully understand the risks it presents. This is our core principle. As Risky Business Project Co-Chair Michael Bloomberg observes, “if you can’t measure it, you can’t manage it.”⁶

Assessing and managing risk is how businesses, militaries and governments are able to remain productive and successful in an increasingly complex, volatile, and unpredictable global economy.

DEFINING RISK

The risk of a future event can be measured by the probability of the event occurring and the magnitude of the event. The probability of an event occurring is a function of the event’s frequency, duration, and severity. The magnitude of an event is a function of the event’s potential impact on the system. The Risky Business Project defines risk as the potential for a future event to cause a loss of value or damage to the system. This loss of value or damage can be measured in terms of the event’s potential impact on the system’s ability to function and its ability to meet its goals.

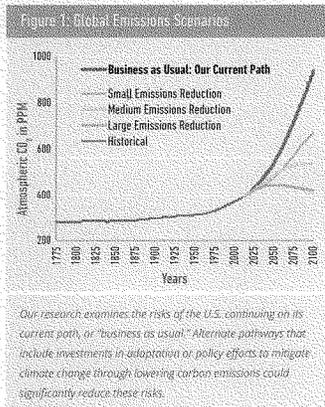
The Risky Business Project defines risk as a range of economic losses caused by climate change. These losses include both direct economic losses (such as property damage) and indirect economic losses (such as lost productivity and lost opportunities).

Climate change is a global phenomenon that will have a significant impact on the global economy. The Risky Business Project defines risk as the potential for a future event to cause a loss of value or damage to the system. This loss of value or damage can be measured in terms of the event’s potential impact on the system’s ability to function and its ability to meet its goals.

Understanding our financial risk and the term “likely” are key for businesses. While we have a 67% chance of occurring, it is considered a “likely” event because the potential impact is significant. While the potential impact is significant, it is not considered a “likely” event because the probability of occurring is less than 50%.

UNDERSTANDING CLIMATE RISK

The risk approach is well suited to the issue of climate change. Even the single term “climate change” is shorthand for a diverse array of impacts, mostly stemming from increased heat in the atmosphere and oceans, but also radiating outward in myriad and geographically diverse ways. For example, in some regions sea levels will likely rise, while in others they may actually fall. In some areas we will likely see increased droughts, whereas in others the combination of heat and humidity could lead to physically unbearable outdoor conditions, with increased risk of heat stroke for the many Americans who work outdoors in sectors such as construction, utility maintenance, transportation, and agriculture.



Moreover, all these conditions can and will change based on the actions we take today and into the future, as well as on unknowable factors such as the precise rate of Arctic and Antarctic ice melt. Thus the “change” part of climate change is the crux of the matter: **To plan for climate change, we must plan for volatility and disruption.**

Risk assessment gives businesses a way to plan for change. From PricewaterhouseCoopers’s 2008 primer, “A Practical Guide to Risk Assessment”:

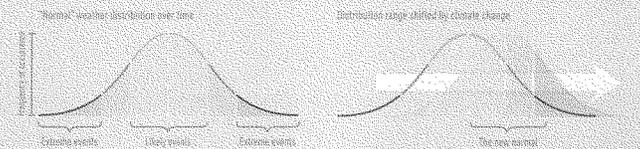
The ability to identify, assess, and manage risk is often indicative of an organization’s ability to respond and adapt to change. Risk assessment . . . helps organizations to quickly recognize potential adverse events, be more proactive and forward-looking, and establish appropriate risk responses, thereby reducing surprises and the costs or losses associated with business disruptions. This is where risk assessment’s real value lies: in preventing or minimizing negative surprises and unearthing new opportunities.

The Risky Business Project examines the risks of the U.S. continuing on its current path, or “business as usual.” This assumes no new national policy or global action to mitigate climate change and an absence of investments aimed at improving our resilience to future climate impacts. Taking these policy and adaptive actions could significantly reduce the risks we face, as illustrated in Figure 1.

Our research analyzes the risks of “business as usual” to specific critical sectors of the economy and regions of the country. We focus in particular on sectors that are already making large, expensive investments in

UNDERSTANDING CLIMATE RISK

Figure 2: How Extreme Weather Events Become the Norm



Human society is structured around "normal" weather, with some days hotter than average and some colder. As the distant "tails" are extreme events such as catastrophic weather, climate change shifts the entire distribution curve to the right. Old extremes become the new normal, new extremes emerge, and the process continues until we take action.

Source: *Risky Business*

infrastructure that will likely last well into the future: **agriculture, energy, and coastal infrastructure**. We also look at the impact of climate change on America's **labor productivity and public health**, which influence multiple economic sectors. These latter impacts also are deeply connected to our shared future quality of life.

As with any risk assessment, our investigation looks at not only the most likely outcomes, but also climate futures that have a lower probability of occurring but particularly severe consequences should they come to pass. (See "Defining Risk" sidebar, p. 9.) This focus on "tail risks" is not unique to climate change. After all, households and businesses pay a premium for insurance to protect themselves against those tail risks, such as the possibility of flood or

fire, that they deem unacceptable. The military plans for a wide range of possible (and sometimes highly unlikely) conflict scenarios, and public health officials prepare for pandemics of low or unknown probability.

When looking at climate change, it's particularly important to consider the outlier events and not just the most likely scenarios. Indeed, the "outlier" 1-in-100 year event today will become the 1-in-10 year event as the Earth continues to warm. Put another way, **over time the extremes will become the "new normal."**

"Risk is like fire: if controlled it will help you, if uncontrolled it will rise up and destroy you."

— Thomas H. Davenport



Talking about climate change in terms of U.S. averages is like saying, 'My head is in the refrigerator, and my feet are in the oven, so overall I'm average.'

— Risky Business Project Co-Chair Tom Steyer⁹

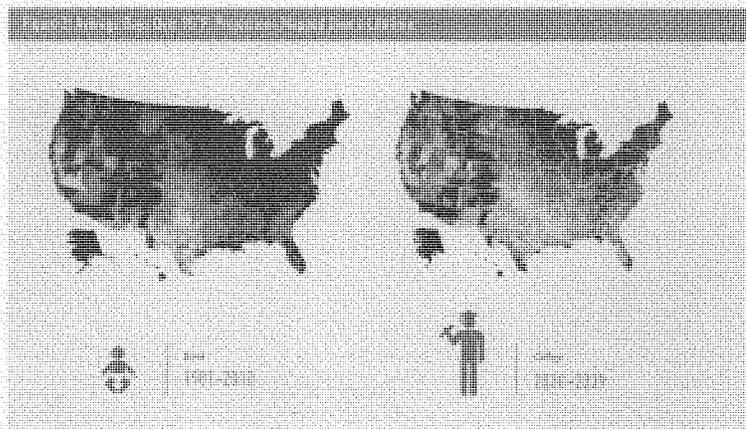
Our risk assessment begins with the straightforward fact that human-induced climate change leads to rising temperatures.

If we continue along our current path, with no significant efforts to curb climate change, the U.S. will likely see significantly more days above 95°F each year. By the middle of this century, the average American will likely see 27 to 50 days over 95°F each year—from double to more than triple the average number of 95°F days we've seen over the past 30 to 40 years. Climate change impacts only accelerate with time, so that by the end of this century we will likely see 45 to 96 days per year over 95°F. That's between one and a half and three months of the year at what are now considered record hot temperatures. To put this in context, by the end of the century, Oregon, Washington, and Idaho could well have more days above 95°F each year than there are currently in Texas.

These are only the most likely scenarios; there are possible lower and higher estimates outside the most likely range. Within that range, there are also disparities, of course: As the maps that follow demonstrate, some regions of the country will be far harder hit by extreme heat than others, and some will experience rising temperatures in terms of warmer winters rather than unbearable summers.

What matters isn't just the heat, it's the humidity—or, in this case, a dangerous combination of the two. One of the most striking findings in our analysis is that increasing heat and humidity in some parts of the country could lead to outside conditions that are literally unbearable to humans, who must maintain a skin temperature below 95°F in order to effectively cool down and avoid fatal heat stroke. The U.S. has never yet seen a day exceeding this threshold on what we call the "Humid Heat Stroke Index," but if we continue on our current climate path, this will change, with residents in the eastern half of the U.S. experiencing 1 such day a year on average by century's end and nearly 13 such days per year into the next century.

RESULTS: RISKS VARY BY REGION & SECTOR



Heat Map Key:

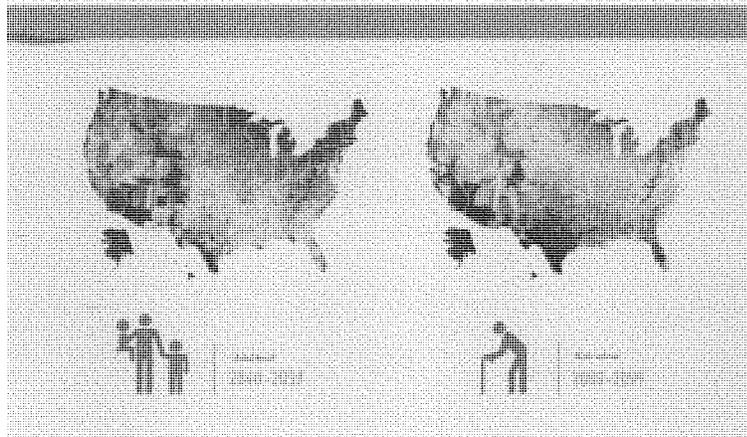
Average Days Per Year Over 95°F



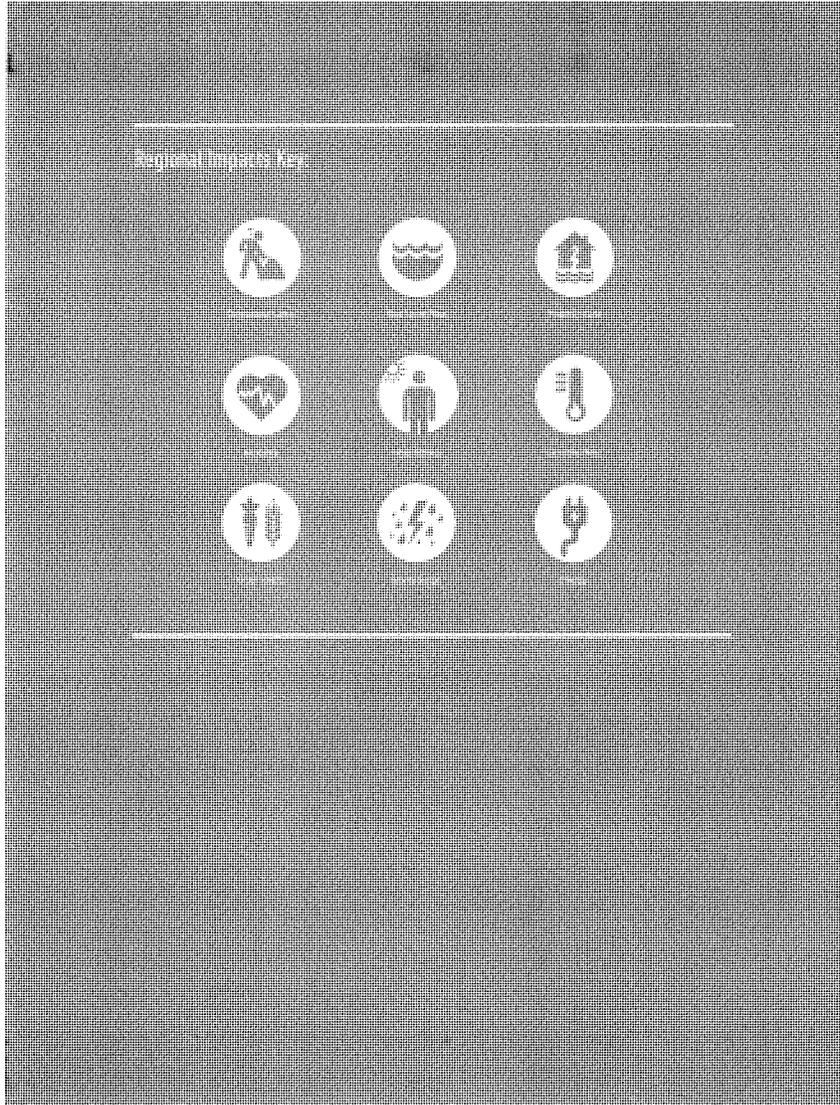
On our current path, the U.S. will likely see significantly more days above 95°F each year. Some regions of the country will be hit far harder by extreme heat than others, and some will experience rising temperatures

in terms of warmer winters rather than unbearable summers. But by the end of this century, the average American will likely see 45 to 96 days per year over 95°F.

Data Source: Rhodium Group

RESULTS: RISKS VARY BY REGION & SECTOR

By the end of the century, Oregon, Washington, and Idaho could well have more days above 95°F each year than there are currently in Texas; babies being born right now in the Southwest could see nearly four additional months of days over 95°F within their lifetimes.



RESULTS: RISKS VARY BY REGION & SECTOR

Heat is a critical issue for the health of businesses as well as that of human beings. On their own, rising temperatures can have significant negative impacts on health and also labor productivity. But high temperatures are also at the root of several other important climate impacts that have long been recognized by scientists:

- Hotter air on the Earth's surface leads to higher ocean temperatures, which causes ocean expansion and sea level rise;
- Higher temperatures accelerate the rates at which land ice melts, further elevating average sea levels;
- A warmer atmosphere makes extreme precipitation more likely, which is expected to make wet regions even wetter, but could also make dry regions even drier.

Because the U.S. is such a large and geographically diverse country, it will experience every one of these climate impacts in the next century. Even the individual sectors we studied have regional variations: For agriculture, for instance, the national story is one of an industry able to adapt by changing where and what farmers plant; at the same time, the story within particular regions is quite different, as individual farmers potentially abandon traditional crops or move away from the farming business altogether. For the energy industry, the story in the warming North is starkly different than in the increasingly unbearably hot South. Sea levels, too, vary significantly across the U.S., and even across cities along the same coastline: For example, sea level rise at New York will likely be higher than at Boston, and sea level rise at San Diego will likely be higher than at San Francisco.

As in a standard business risk assessment, we looked at the data to see exactly where the greatest risks lie, and confirmed that some regions and economic sectors face extreme and unacceptable risks. These are some of our gravest concerns:



Rising seas and greater coastal storm damage already threaten the financial value and viability of many properties and infrastructure along the Eastern Seaboard and Gulf Coast. If we stay on our current climate path, some homes and commercial properties with 30-year mortgages in places in Virginia, North Carolina, New Jersey, Alabama, Florida, and Louisiana and elsewhere could quite literally be underwater before the note is paid off.



Rising temperatures will also reduce labor productivity, as some regions—especially the Southeast and Southwest—become too hot by mid-century for people to work outside during parts of the day.

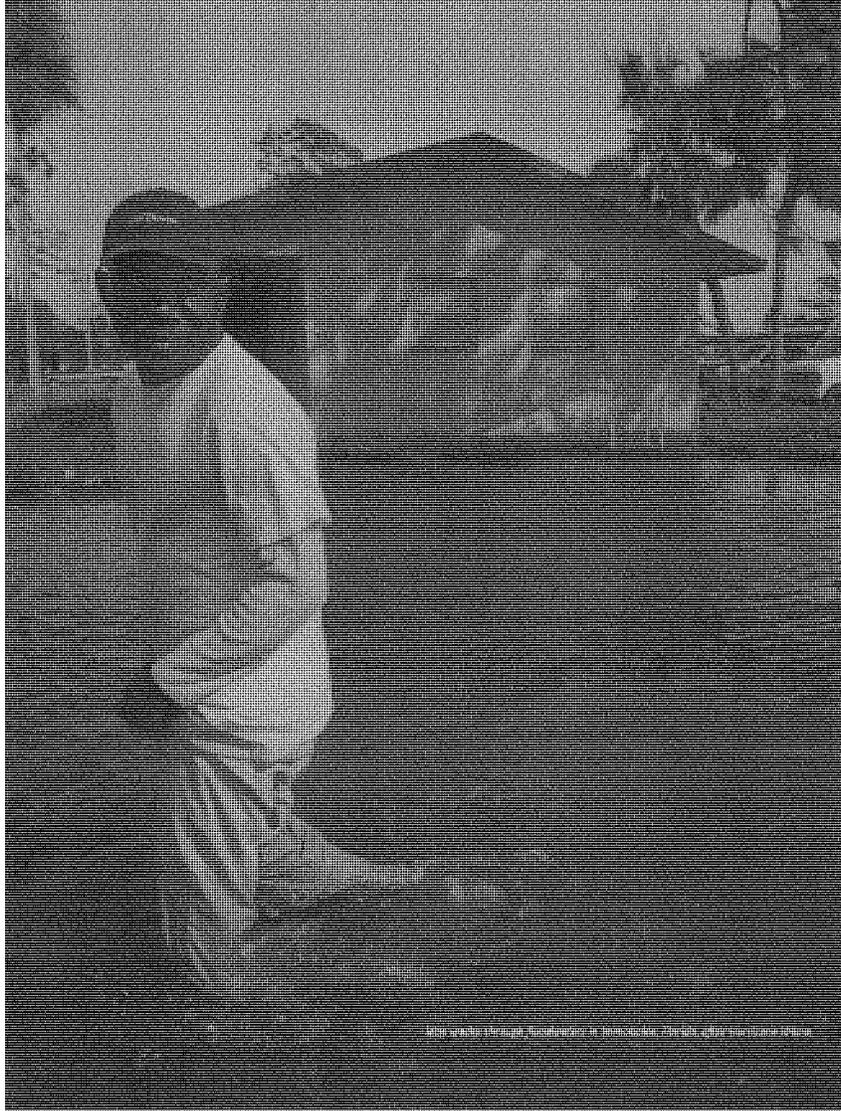


Heat will also put strains on our energy system, simultaneously decreasing system efficiency and performance as system operators struggle to cool down facilities, and increasing electricity consumption and costs due to a surge in demand for air conditioning.



As parts of the nation heat up, the worst health impacts will be felt among the poor—many of whom work or even live outdoors or can't afford air conditioning at home—and among those too elderly or frail to physically withstand the heat or get themselves to air-conditioned facilities.

More than any other factor, our direct economic exposure to climate change will be determined by where we do business. For that reason, we present our findings below in terms of the major regions of the U.S., and then identify how climate change will affect critical sectors within those regions. Still, as any business person knows, these impacts won't be contained within regional boundaries; the ripple effects are likely to resonate throughout the economy. Put another way, just because it's not hot where you are doesn't mean you won't feel the heat of climate change.





The Risky Business analysis builds on the research and analytical work done over the past several decades by international climate scientists and economists, including the recent National Climate Assessment (NCA), released in early May 2014. The Risky Business Project takes as our unit of measurement the National Climate Assessment's regions, which are organized loosely around shared geographic characteristics and climate impacts.¹¹ These are: Northeast, Southeast, Midwest, Southwest, Great Plains, Northwest, Alaska, and Hawaii.

However, we went even deeper than the NCA, conducting analysis down to the county level in some cases, and also focusing on key economic sectors. We overlaid our regional climate impact findings with an economic analysis showing the potential cost of these impacts within those regions and sectors. Below, we explore the most striking findings from each region. We encourage readers to go to riskybusiness.org to explore these regional impacts in more depth and to climateprospects.org for the independent research team's complete risk assessment.

WHY REGIONS MATTER

In a country as large and diverse as the U.S., a broad, nationwide analysis of economic and policy implications is not possible. Instead, we must focus on regional impacts. To that end, the National Climate Assessment (NCA) in the last quarter of 2010, every state in the nation was divided across the issue of climate, which led to the creation of seven regional climate impact teams. The following year, seven regional assessment teams were set up, each focusing on a specific region: Northeast, Southeast, Midwest, Southwest, Great Plains, Northwest, Alaska, and Hawaii.

Regions also have a cultural dimension. Americans often think of themselves as "belonging" to specific regions, and this sense of regional identity is a key part of their self-identity. The NCA's regional assessment teams were set up to assess the impact of climate change on these regions and sectors. The NCA's regional assessment teams were set up to assess the impact of climate change on these regions and sectors. The NCA's regional assessment teams were set up to assess the impact of climate change on these regions and sectors.

The regional nature of climate impacts and the regional nature of the political and economic and cultural identity means that there may not be one single national answer to the risks highlighted by the Risky Business Project. The variability of these impacts, especially in the Southeast and Southwest—which will likely experience the most intense heat and sea level rise—will vary significantly across the country, and the impacts will be felt differently by different sectors and regions. The regional nature of climate impacts and the regional nature of the political and economic and cultural identity means that there may not be one single national answer to the risks highlighted by the Risky Business Project. The variability of these impacts, especially in the Southeast and Southwest—which will likely experience the most intense heat and sea level rise—will vary significantly across the country, and the impacts will be felt differently by different sectors and regions.

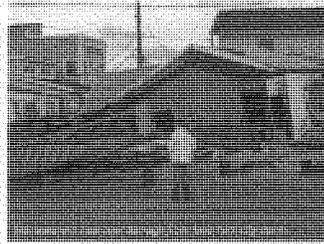
NORTHEAST



While the Northeast region of the U.S. is expected to experience a sizeable increase in temperatures and average number of extremely hot days over the course of the century, the region's major climate impact will be sea level rise and its effect on coastal infrastructure.

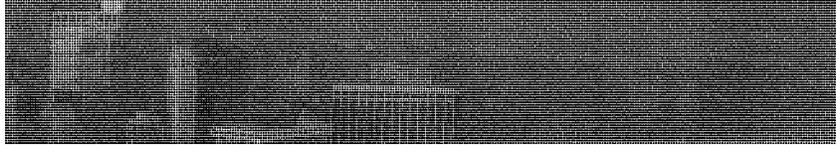
Rising sea levels are a direct consequence of rising temperatures: As the oceans warm, they expand. This phenomenon is further exacerbated by land-ice melt, particularly the Antarctic and Greenland ice sheets. Scientists have recently found evidence of accelerating and perhaps unstoppable land ice melt in West Antarctica.¹⁴ A further (and more minor) contributor to sea level rise is groundwater withdrawal, which can literally sink the land adjacent to the ocean. All of these factors—thermal expansion, ice melt, and groundwater withdrawal—can lead to higher water levels along the coasts.

Why do sea levels matter to the American economy? First and foremost, sea level rise threatens the communities and industries along our coastlines. The coasts are critical to the Northeast region's economy; its major cities are on the water, as are many of its major industries, from New York's Wall Street to the fisheries in Portland, Maine. All told, 88% of the population of this region lives in coastal counties, and 68% of the region's Gross Domestic



Product (GDP) is generated in those counties. As a result, much of the region's residential, commercial, and energy infrastructure is also at or near sea level, making these assets particularly vulnerable to climate impacts.

The Risky Business analysis shows that if we continue on our current path, sea levels at New York City will likely rise by an additional 0.9 feet to 1.6 feet by mid-century, and between 2.1 feet and 4.2 feet by the end of the century. Because our risk assessment includes less likely but higher-impact possibilities, we also found a 1-in-100 chance that New York City could experience more than 6.9 feet of sea level rise by the end of the century. The story for New Jersey is even more concerning because of that state's groundwater withdrawal: It's likely that, on our current path, Atlantic City will see 2.4 feet to 4.5 feet of sea

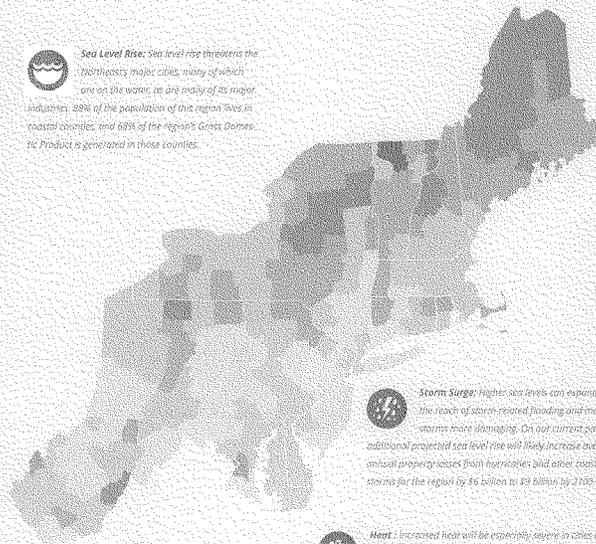


NORTHEAST

NORTHEAST: AVERAGE SUMMER TEMPERATURE BY 2100 & KEY IMPACTS



Sea Level Rise: Sea level rise threatens the Northeast's major cities, many of which are on the water. In the study of its major industries, 88% of the population of this region lives in coastal counties, and 89% of the region's Gross Domestic Product is generated in those counties.



Storm Surge: Higher sea levels can expand the reach of storm-related flooding and make storms more damaging. On our current path, additional projected sea level rise will likely increase average annual property losses from hurricanes and other coastal storms for the region by \$6 billion to \$9 billion by 2100.



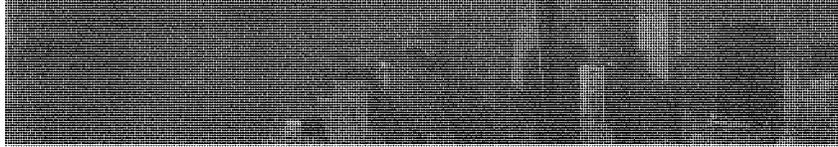
Heat: Increased heat will be especially severe in cities and metro regions with more than 1 million people, where the high concentration of concrete and lack of natural cooling systems like streams and forests creates an "urban heat island" effect that can raise average temperatures by as much as 5.4°F during the day and 22°F in the evening over the surrounding rural areas.

Average Summer Temperature (°F)



Data Source: Rhodium Group





NORTHEAST

level rise by end of this century. North of New York City, the rise is slightly smaller: Boston will likely experience 2 feet to 4 feet by 2100, and Portland is likely to experience a rise of 1.7 feet to 3.8 feet in the same period.

Just looking at the simple rise in sea levels masks the impact these higher levels can have during a major storm. Sea level rise that had already occurred over the past century exacerbated storm surge during Hurricane Sandy, expanding the reach of the storm-related flooding and making the storm more costly. Our research shows that, if we continue on our current path, additional projected sea

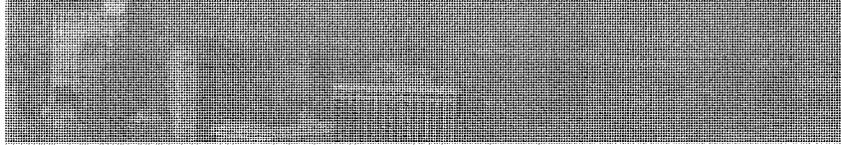
level rise will likely increase average annual property losses from hurricanes and other coastal storms by \$6 billion to \$9 billion over the course of the century. Potential changes in hurricane activity, also caused by atmospheric warming, would raise these estimates to \$11 billion to \$17 billion—a 2-to-3-fold increase from current levels.

The Northeast will also suffer from increased heat, especially because so many of the region's residents live in cities that have higher temperatures due to the so-called "heat island effect." In cities and metro regions with more than 1 million people, the high concentration of concrete and lack of natural cooling systems like streams and forests can raise average temperatures by as much as 5.4°F during the day and 22°F in the evening over the surrounding rural areas.¹⁵



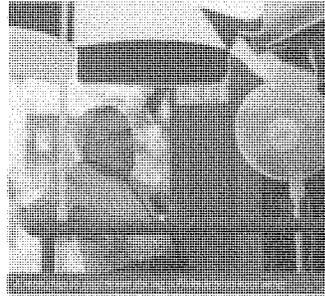
Source: Risk Management Solutions (RMS)

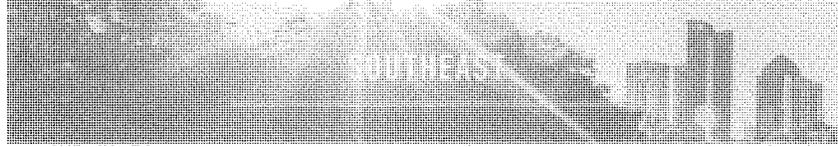




NORTHEAST

Right now, the Northeast is actually rather temperate in the summer, with only 2.6 days over 95°F on average each year—a temperature we refer to throughout our research as “extremely hot.” By mid-century, the average resident in the Northeast will likely see between 4.7 and 16 additional extremely hot days; by late century this range will likely jump to between 15 and 57 additional extremely hot days, or up to two additional months of extreme heat. As we discuss further in the Southeast section below, these increasingly hot summers will have serious negative effects on health, mortality, and labor productivity.



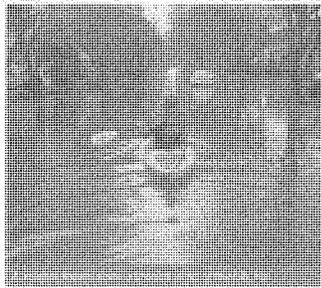


Like the Northeast, the Southeastern U.S. has many coastal communities, though in this region only 36% of residents live in coastal counties, with 33% of GDP coming from those counties.

However, **sea level rise could seriously threaten the Southeast's coastal infrastructure**, given that some of the region's major cities (e.g., New Orleans) are at or below sea level while others (e.g., Miami) are built on porous limestone that allows water inundation even in the presence of a sea wall. Much of the region's critical infrastructure—including roads, rails, ports, airports, and oil and gas facilities—also sits at low elevations.

Our research shows a significant risk to this region from sea level rise. On our current path, by mid-century, mean sea level at Norfolk, Virginia—home to the nation's largest naval base—will likely rise between 1.1 feet and 1.7 feet, and will rise 2.5 feet to 4.4 feet by the end of century. However, there is a 1-in-100 chance that Norfolk could see sea level rise of more than 7.2 feet by the end of the century (Figure 7).

In Florida, because of the porous limestone on which the major southern cities are built, even modest sea level rise comes at a significant economic cost. Under current projections, between \$15 billion and \$23 billion of existing property will likely be underwater by 2050, a number that grows to between \$53 billion and \$208 billion by the end



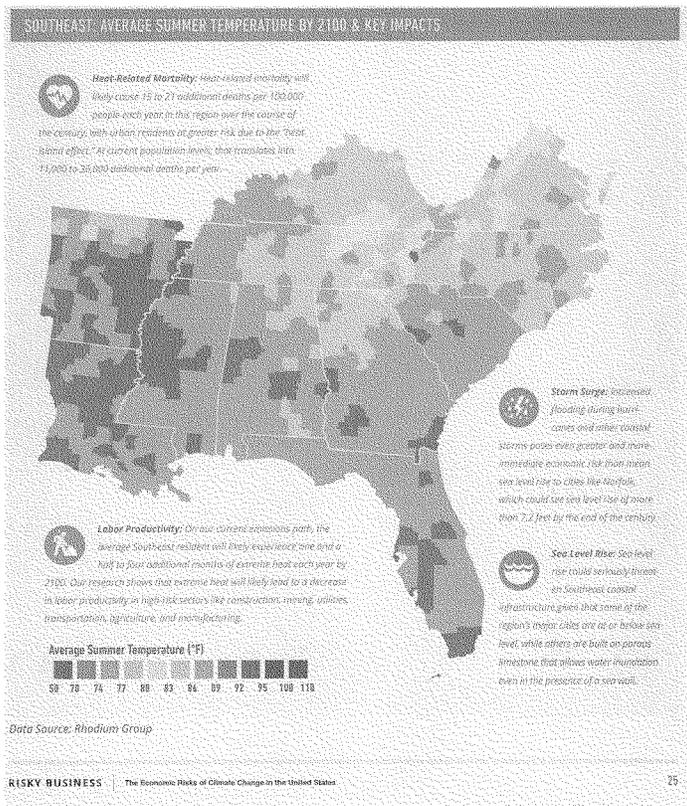
of the century. There is a 1-in-20 chance that more than \$346 billion in current Florida property will be underwater by the end of this century, and a 1-in-100 chance that more than \$681 billion in property will be below mean sea levels. An additional \$240 billion in property will likely be at risk during high tide that is not at risk today.

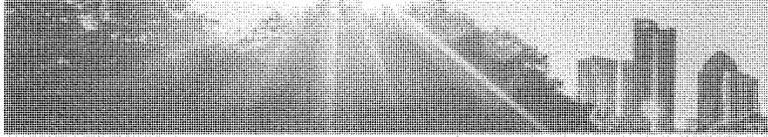
As in the Northeast, greater flooding during hurricanes and other coastal storms, plus potential changes in hurricane activity, pose even greater and more immediate economic risks than mean sea level rise.

The Southeast will also likely be hit hardest by heat impacts. Over the past 30 years, the average resident of this region has experienced about 9 days per year at 95°F



SOUTHEAST

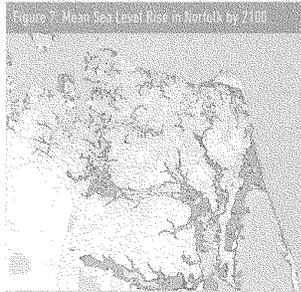




SOUTHEAST



or above. Looking forward, if we continue on our current emissions path, the average Southeast resident will likely experience an additional 17 to 53 extremely hot days per year by mid-century and an additional 47 to 115 days per year by the end of the century. That's one and a half to

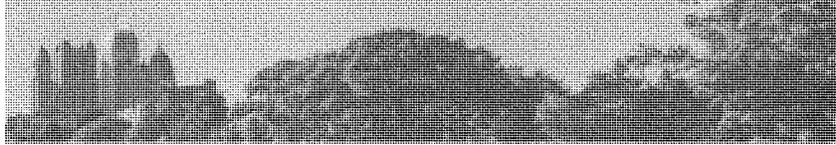


Source: RMS

four additional months of extreme heat each year.

This kind of weather could have serious economic impacts. Our research shows a **decrease in labor productivity in high-risk sectors** like construction, mining, utilities, transportation, agriculture and manufacturing of up to 3.2% by the end of the century in this region, and a smaller but still noticeable impact on labor productivity in low-risk sectors like retail trade and professional services.

We are also likely to see an additional 15 to 21 deaths per 100,000 people every year in this region over the course of the century due to **increases in heat-related mortality**, with urban residents at greater risk due to the heat island effect. At the current population of the Southeast, that translates into 11,000 to 36,000 additional deaths per year.



SOUTHEAST



Data Source: Radium Group

As Risk Committee member Dr. Alfred Sommer has pointed out, extreme heat will have a major impact on the capacity of local hospitals: "We just don't have the surge capacity left in the medical system anymore. . . .

If these [impacts] occur in rural areas you're particularly in trouble."¹⁶ He goes on to note that in Chicago during the 1995 heat wave, local officials "didn't even have a place to properly store [bodies from] the 700 deaths . . . that occurred over a small number of days."¹⁷



The upper Midwest economy is dominated by commodity agriculture, with some of the most intensive corn, soybean, and wheat growing in the world.

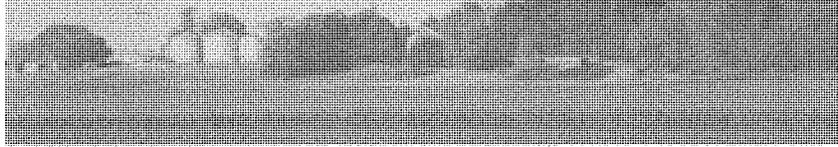
Overall, the agricultural industry in this region includes more than 520,000 farms valued at \$135.6 billion per year as of 2012, and the region accounts for 65% of national production of corn and soybeans alone.¹⁸ For the Midwest, commodity agriculture is a crucial business, and the health and productivity of the agricultural sector is inextricably intertwined with climate conditions. Our research shows that under the “business as usual” scenario and assuming no significant adaptation by farmers, some states in the region, like Missouri and Illinois, face up to a 15% likely average yield loss in the next 5 to 25 years, and up to a 73% likely average yield loss by the end of the century. Assuming no adaptation, the region as a whole faces likely yield declines of up to 19% by mid-century and 63% by the end of the century.

Yet while the agricultural industry will clearly be affected by climate change, it is also probably the best equipped to manage these risks. Farmers have always adapted to changing weather and climate conditions, with adaptation and flexibility built into their business models. Armed with the right information, Midwest farmers can, and will, mitigate some of these impacts through double- and triple-cropping, seed modification, crop switching

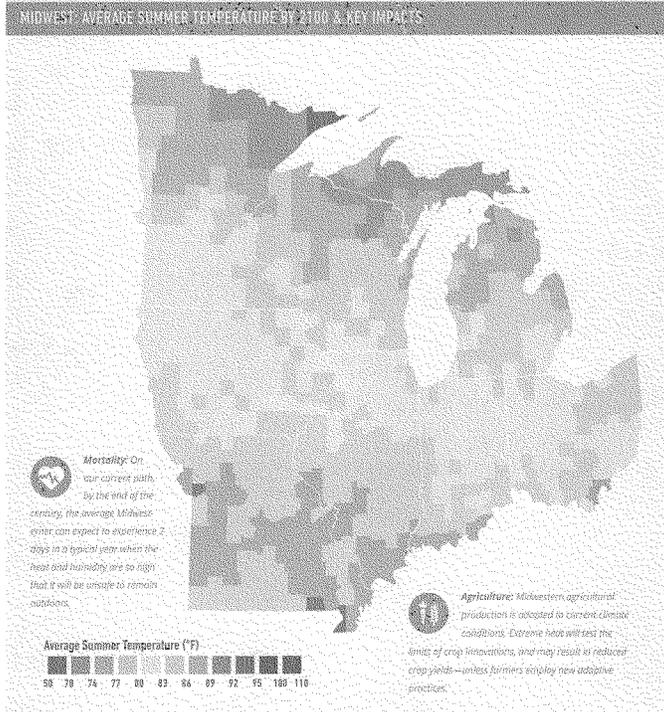


and other adaptive practices. In many cases, crop production will likely shift from the Midwest to the Upper Great Plains, Northwest, and Canada, helping to keep the U.S. and global food system well supplied. However, this shift could put individual Midwest farmers and farm communities at risk if production moves to cooler climates.

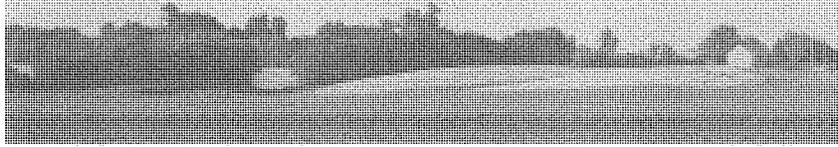
The projected increase in Midwest surface air temperatures won't just affect the health of the region's crops; it will also put the region's residents at risk. Over the past 40 years, the Midwest experienced only 2.7 days on average over 95°F. If we stay on our current climate path, the average Midwest resident will likely experience an additional 7 to 26 days above 95°F each year by mid-century, and 20 to 75 additional extreme-heat



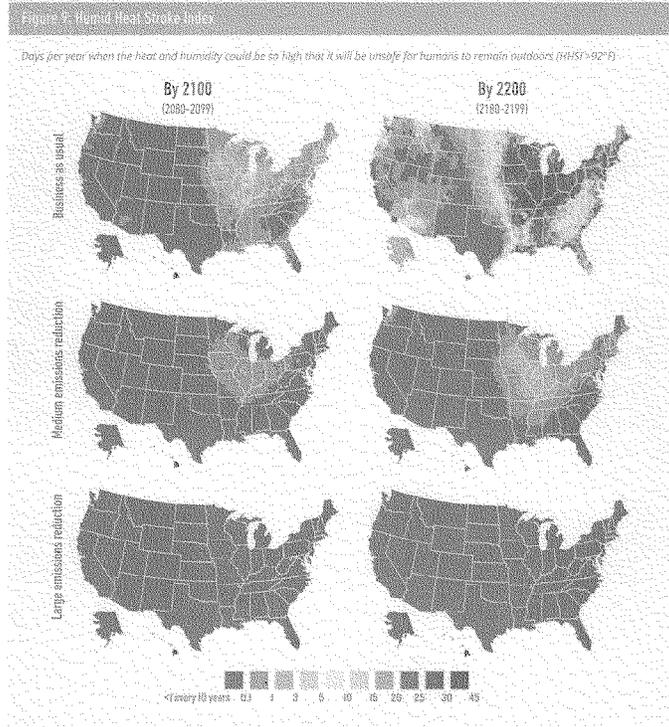
MIDWEST



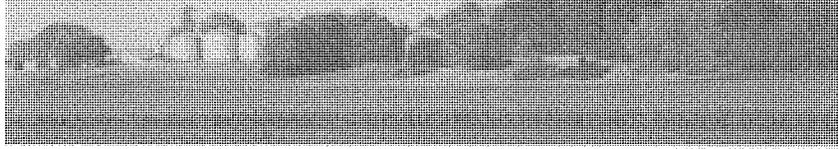
Data Source: Rhodium Group



MIDWEST



Data Source: Rhodium Group

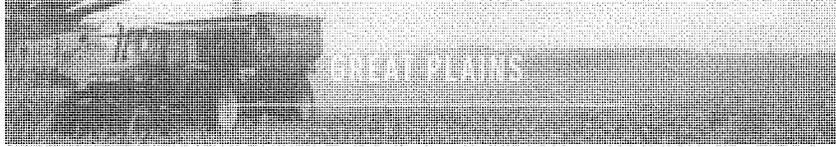


MIDWEST

days—potentially more than 2 additional months per year of extreme heat—by the end of the century. On the other hand, the region will also experience fewer winter days with temperatures below freezing.

But the real story in this region is the combined impact of heat and humidity, which we measure using the **Humid Heat Stroke Index, or HHSI**. The human body's capacity to cool down in the hottest weather depends on our ability to sweat, and to have that sweat evaporate on our skin. Sweat keeps the skin temperature below 95°F, which is required for our core temperature to stay around 98.6°F. But if the outside temperature is a combination of very hot and very humid—if it reaches a HHSI of about 95°F—our sweat cannot evaporate, and our core body temperature can rise until we actually collapse from heat stroke. Even at an HHSI of 92°F, core body temperatures can get close to 104°F, which is the body's absolute limit.

To date, the U.S. has never experienced heat-plus-humidity at this scale. The closest this country has come was in 1995 in Appleton, Wisconsin, when the HHSI hit 92°F. (At the time, the outside temperature was 101°F and the dew point was 90°F.) The only place in the world that has ever reached the unbearable HHSI of 95°F was Dhahran, Saudi Arabia, in 2003 (outside temperature of 108°F, dew point of 95°F). Our research shows that if we continue on our current path, the average Midwesterner could see an HHSI at the dangerous level of 95°F two days every year by late century, and that by the middle of the next century, she or he can expect to experience 20 full days in a typical year of HHSI over 95°F, during which it will be functionally impossible to be outdoors.



The Great Plains region stretches from the far north (Montana) to the far South (Texas). Climate impacts will be felt very differently in the northern and southern parts of this region.

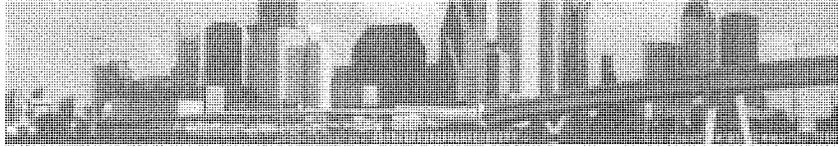
In the southern states of the Great Plains region (Texas, Oklahoma, and Kansas), our research shows an increase in extremely hot days. The average resident of these states experienced 35 days per year over 95°F in the past 30 years. This number will likely increase by 26 to 56 additional extremely hot days by mid-century and 56 to 108 days per year by the end of the century—for a total of between three and four months of additional extreme hot days per year.

At the same time, the northern parts of the region will likely see a significant decrease in extremely cold days: from the average of 159 days per year of below-freezing weather over the past 30 years, to between 117 and 143 freezing days at mid-century, and between 79 and 122 freezing days by the end of the century.

The southern and coastal parts of this region will also experience the **sea level rise impacts on coastal communities** that we've already discussed. In Texas, for instance, where about one-third of the state's GDP is generated in coastal counties, sea levels will likely rise by 1.5 to 2 feet by mid-century and 3.2 to 4.9 feet by the end of the century, with a 1-in-100 chance of a 7.0 foot rise.

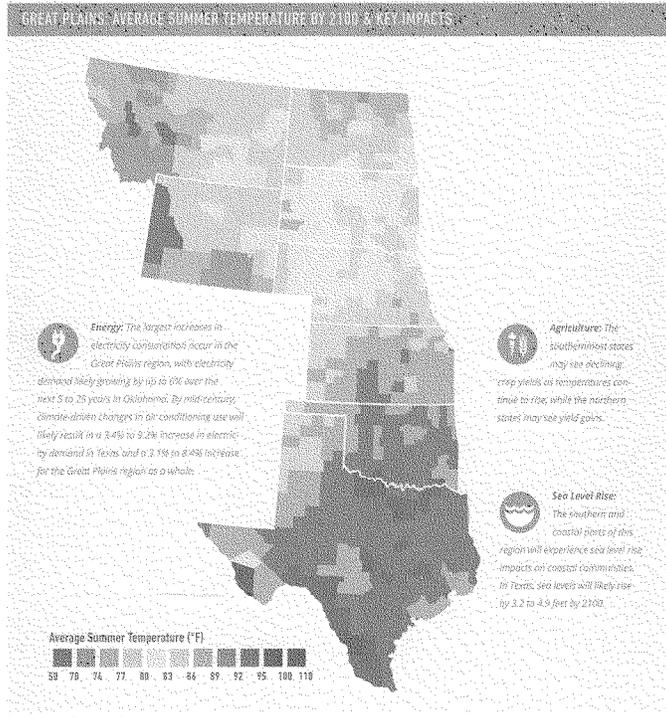
Though the north and south sub-regions of the Great Plains have starkly different climates, all the states in this region rely on two important climate-sensitive industries: agriculture and energy.

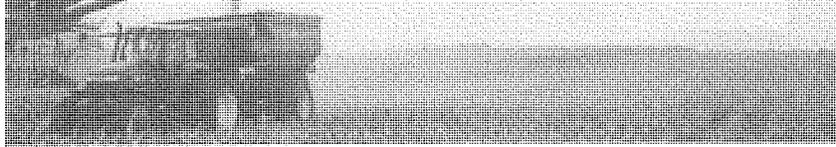
Altogether, 80% of the region is devoted to cropland, pastures, and range land, which produce \$92 billion in agricultural products each year. The story for the region's agricultural sector is mixed: The more southern states may see declining crop yields as temperatures continue to rise, while the northern states may actually see yield gains, though this will depend on a number of factors, including water availability. (See the Southwest section for a more detailed discussion of this factor.)



GREAT PLAINS

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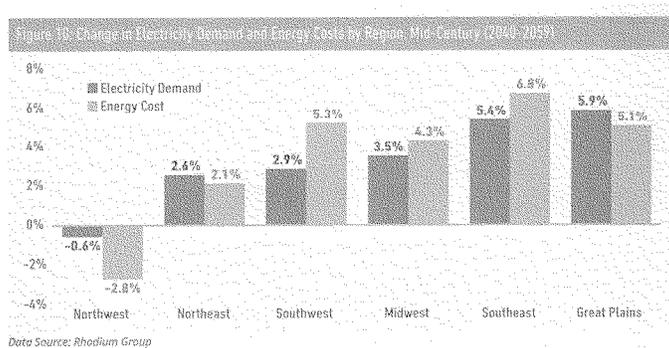
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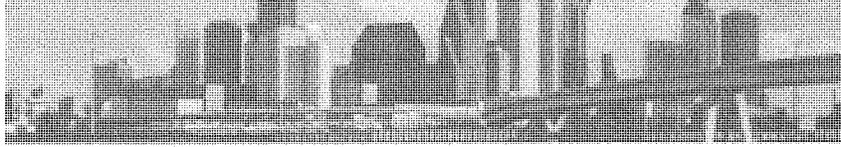
At the same time, the region is a major energy producer for the nation, making **climate impacts on the energy sector** particularly important for this area. Texas and Wyoming alone produce half of U.S. energy (primarily from crude oil and natural gas in Texas and coal in Wyoming), and North Dakota has recently become a major oil and gas producer. Power generation facilities in the region currently meet about 17% of the nation's overall electricity needs.¹⁹

If we stay on our current path, our research shows a significant increase in demand for air conditioning over the course of the century which, when combined with other heat-related impacts such as reductions in power generation and in transmission efficiency and reliability, could place a considerable burden on the electricity

power sector. As soon as 5 to 25 years from now, our research shows a 0.8% to 2.2% likely increase in nationwide electricity consumption. The country will likely see a roughly corresponding decline in demand for heating, as temperatures warm up in the northern states, but the switch from natural gas and fuel oil-driven heating demand to electricity powered cooling demand has significant implications for the U.S. energy system.

The largest increases in electricity consumption occur in the Great Plains region, with likely electricity demand growth in Texas and Oklahoma of up to 5% and 6% respectively over the next 5 to 25 years. By mid-century, climate-driven changes in air conditioning will likely result in a 3.4% to 9.2% increase in electricity demand in Texas and a 3.1% to 8.4% increase for the Great Plains region as a whole.



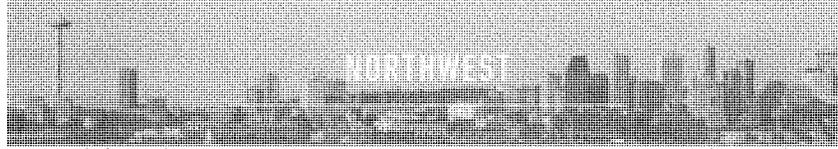


GREAT PLAINS



Most of this increase will occur during times of the day when electricity consumption is already high. Meeting higher peak demand will likely require the construction of up to 95 GW of additional power generation capacity over the next 5 to 25 years, the rough equivalent of 200 average-size coal or natural gas power plants. Constructing these new power-generation facilities will, in turn, raise residential and commercial energy prices. Our research concludes that climate-driven changes in heating and cooling will likely increase annual residential and commercial energy costs nationally by \$474 million to \$12 billion over the next 5 to 25 years and \$8.5 billion to \$30 billion by the middle of the century.

All of this could have a significant impact on the economy of the Great Plains. In addition, many of the region's current energy-production facilities—from power plants to oil and gas platforms—are at risk from climate-driven increases in storm surge and potential changes in hurricane activity. If these facilities are flooded, the region will lose electricity and energy resources just as the country's need for them is growing.



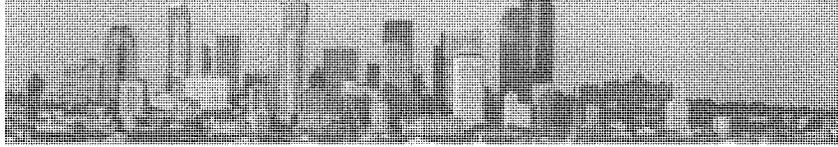
The Pacific Northwest is a good example of the general truth that similar climate impacts may be felt differently from one region to another.

For example, by mid-century this area will have fewer additional extremely hot days than, say, the Southeast—but the average Northwest resident will likely go from experiencing only 5 days of 95°F or warmer temperatures per year on average for the past 30 years to an additional 7 to 15 extremely hot days by mid-century, and to an additional 18 to 42 extremely hot days by the end of the century. This represents an increase of 3 to 8 times the number of hot days for the region per year, which is a significant change from historic norms.

This region is also coastal, but the extent of expected sea level rise here is more varied than the east coast. Because the area is relatively close to the Alaskan glaciers, the Earth's gravitational field may lead to the ice melt in Alaska actually lowering sea levels off Washington and Oregon. At the same time, West Antarctic melt may lead to higher sea level rise in the Northwest over the long term. This latter effect is captured in our analysis of the "tail risk" of sea level rise in the Northwest. Overall, our research shows that if we stay on our current path, sea level at Seattle will likely rise by 0.6 to 1.0 foot between 2000 and 2050 and by

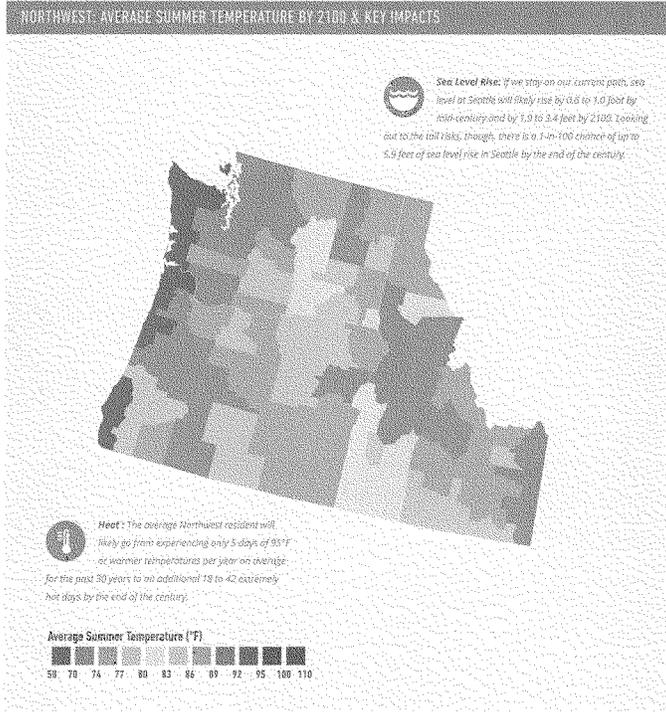
1.6 to 3.0 feet between 2000 and 2100. Looking out to the tail risks, though, there is a 1-in-100 chance of more than 5.9 feet of sea level rise by 2100 in Seattle.

The economy of the Northwest is dependent on its coastlines, but it is also heavily dependent on its forests. Oregon and Washington are the number one and two softwood-producing states in the nation, respectively;²⁰ these two states plus Idaho produce more than \$11 billion in primary wood product sales.²¹ Our review of existing research suggests the Northwest's forests will experience significant potential impacts from climate change, in particular from wildfire—due to both increased drought and to wood damage from pests surviving warmer winters. One study we reviewed found that if temperatures rise 3.2°F by mid-century, this could lead to 54% increase in the annual area burned in the western U.S.²² The same study found that the forests of the Pacific Northwest and Rocky Mountains will likely experience the greatest increases in annual burn area (78% and 175%, respectively).

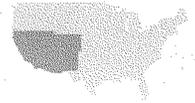
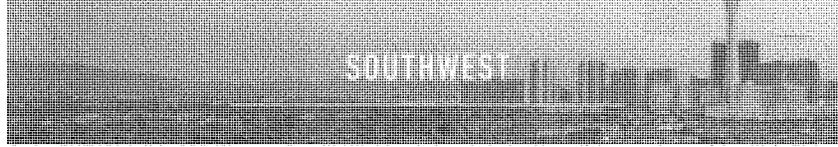


NORTHWEST

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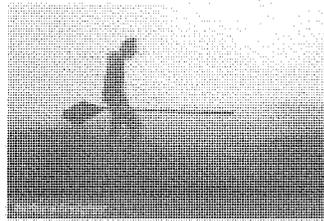
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The Southwest region includes the traditional Southwest states—Arizona, Colorado, Nevada, New Mexico, Utah—and also California. As such, it is an extremely diverse region that in some ways serves as a microcosm of all the climate impacts we've discussed so far.

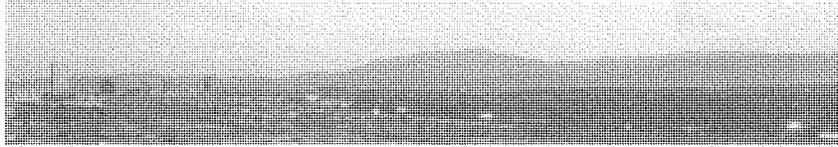
This region is already warm and dry—about 40% of this area is covered by desert²²—and is likely to become more so in the coming decades. Over the past 30 years, the average Southwest resident experienced 40 days per year of temperatures of 95°F or more. If we continue on our current path, by mid-century the average Southwest resident will likely see 13 to 28 additional extremely hot days. By the end of the century, this number will likely rise to an additional 33 to 70 days of extreme heat due to climate change. That translates to one to two additional months of days over 95°F each year within the lifetime of babies being born right now in this region—one of the fastest-growing in the United States.

Because it includes California, the Southwest is not just one big desert; it is also an extremely coastal region. Eighty-seven percent of all Californians live in coastal counties, and 80% of the state's GDP is derived from those counties. Along the coastline of San Diego, if we continue on our current path, sea level will likely rise by 0.7 to 1.2 feet before the middle of the century, and

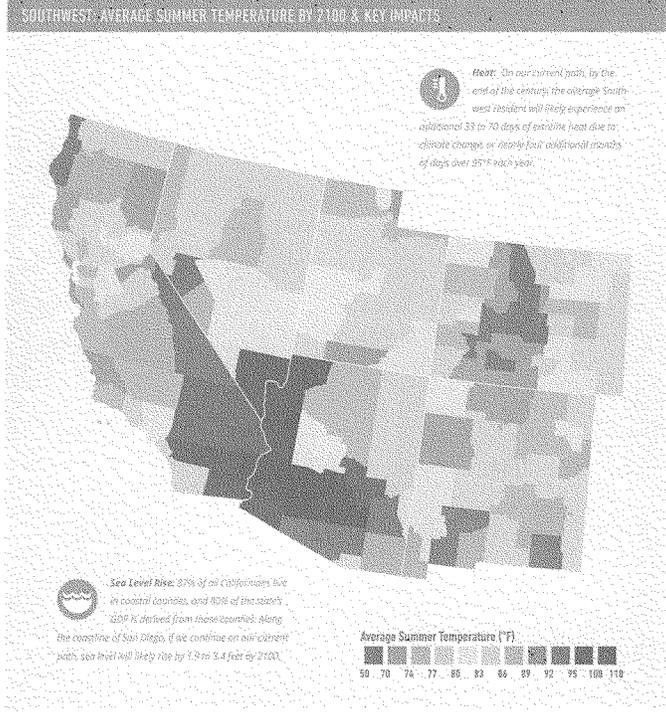


by 1.9 to 3.4 feet by the end of the century. But the real sea level risk in this region is in the tails. The California coastline is more exposed to sea level rise resulting from Antarctic melt than the global average, and there is a 1-in-100 chance that sea levels could rise by more than 6.3 feet by 2100 in San Diego.

San Diego is of strategic importance to the U.S. military: The city is home to three Marine installations, including Marine Corps Base Camp Pendleton, three naval bases, and a Coast Guard station. Fortunately, the military is one of our country's leading institutions in terms of acknowledging the potential impact of climate risk on its installations here and throughout the U. S. The Department of Defense's 2010 Quadrennial Defense Review called for a climate impact assessment at all DOD's permanent installations, and several studies are already underway.²⁴



SOUTHWEST



Data Source: Rhodium Group



SOUTHWEST

in part because of tectonic plate activity in California, sea level rise will vary across the state: Los Angeles (1.5 to 2.9 feet by 2100), Santa Monica (1.7 to 3.1 feet by 2100), and San Francisco (1.8 to 3.2 feet by 2100) will likely see lower rise than San Diego.

While extreme heat days in the Midwest and Southeast will likely be coupled with high humidity, here in the Southwest the days will likely be hot and dry, increasing the potential of wildfires and drying up water sources. While we did not quantify the impact of climate change on either forestry or water availability, these are significant climate risks in the Southwest region, and both are ripe for further analysis.

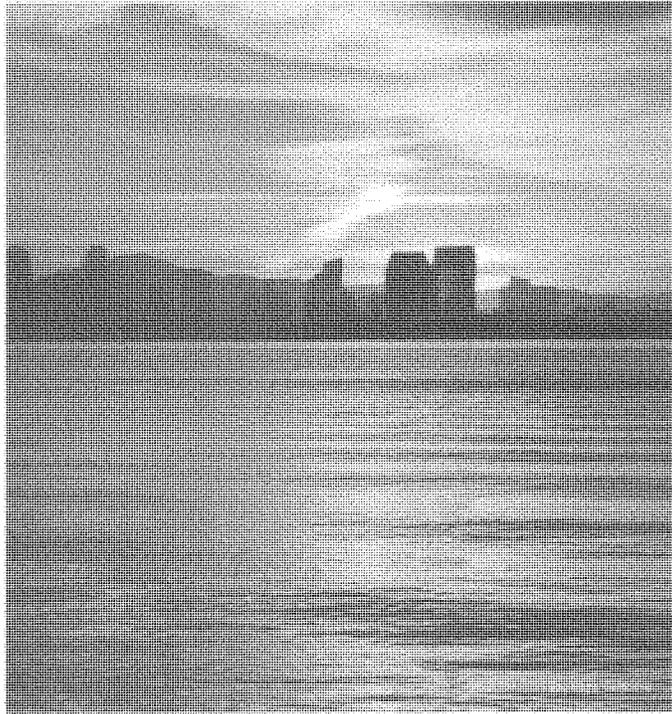
As the Southwest climate heats up, the region is likely to see significantly less snow in the mountains, leading to decreases in spring runoff especially in California and the Southern Rockies. Extreme heat may also lead to higher evaporation of existing reservoirs. This translates into less available groundwater for critical industries such as agriculture, as well as for simple drinking and bathing. Even as temperatures rise, increased energy demand from air conditioning will likely lead to increased water demand, since electricity generation is heavily water dependent. Decreased water availability is also likely to be the most significant impact on this region's agricultural industries, which tend to be non-commodity crops (tree nuts, fruits, etc.) and therefore are not included in our quantitative analysis of the agricultural sector.

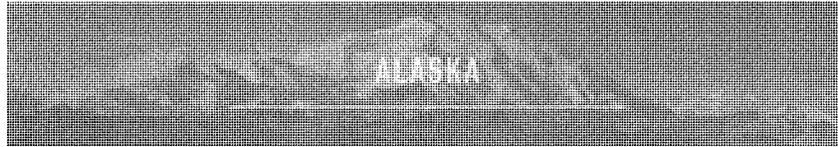
A broad range of issues impact real estate, construction, and urban development. Obviously coastal inundation is one of those. Another is the implication of extreme weather events even within the internal parts of the country. . . . Some of the most water scarce areas of the country are due to get less precipitation. Areas that are dry are going to get drier. And that has immense implications for cities in the west.

— Risk Committee member Henry Cisneros²⁴



SOUTHWEST



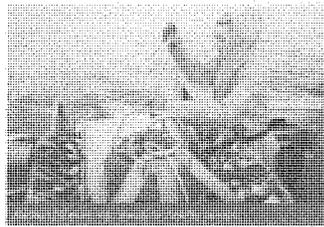


Alaska is ground zero for U.S. climate impacts. The state relies heavily on three climate-sensitive commodities: oil and gas, minerals, and seafood.

More than 80% of the state's GDP comes from oil and gas production, and so increases in energy demand (as discussed above) will dramatically affect this region. Meanwhile, fisheries and tourism, the third and fourth largest contributors to the Alaska economy, depend on healthy oceans and coastal ecosystems.

Our research shows major climactic changes in Alaska over this century. If we continue on our current path, by mid-century Alaska's average temperature will likely rise to between 3.9°F to 8.0°F warmer than it has been over the past forty years. By the end of the century, temperatures will likely rise by 7.6°F to 16°F, but there is a 1-in-20 chance that they will rise even higher, by as much as 19°F. The bulk of this warming is likely to happen in the winter months, significantly decreasing the number of extremely cold days that Alaska now experiences. Up until 2010, Alaska experienced about 188 days per year below freezing; our current path will likely decrease these freezing days by 14% to 25% by mid-century, and by 30% to 50% by the end of this century.

The state is heavily coastal: 84% of Alaskans live in coastal counties, and 85% of the state's GDP comes from these



counties. Sea level is variable around the state, due to the proximity of the glaciers and to shifting tectonic plates.

As in the Pacific Northwest, the state may actually see sea levels go *down* over the course of this century. Our research shows that sea level at Juneau will likely fall by 1.6 to 1.9 feet between 2000 and 2050 and by 2.4 to 3.5 feet between 2000 and 2100. On the other hand, Anchorage will likely experience between a 0.6 feet sea level fall and a 1.2 feet sea level rise by the end of the century, with a 1-in-100 chance of more than a 4.0 foot rise. Prudhoe Bay is likely to experience 2.1 feet to 3.8 feet of sea level rise by 2100, with a 1-in-100 chance of a 6.6 foot rise.



As Alaska is at the center of climate impacts from melting ice, Hawaii is at the center of impacts from sea level rise. This state is 100% coastal in both its population and GDP.

Hawaii is expected to get significantly warmer: On our current path, by mid-century average temperatures will likely be between 1.6°F to 3.6°F warmer than temperatures over the past 40 years. By the end of the century, temperatures will likely increase between 3.7 and 7.7°F. There is also a small but not insignificant chance that Hawaii's average temperatures could rise as much as 9.4°F by the end of the century.

Sea level rise in Hawaii is greater than the global average, and the extreme dependence of this state on the coasts will only intensify this impact. If we continue on our current path, sea level rise at Honolulu is likely 0.8 inches to 1.2 feet greater by mid-century, and 2.1 to 3.8 feet by the end of the century. Looking out at the 1-in-100 tail risk, sea level at Honolulu could rise by more than 6.9 feet by 2100.

Hawaii cannot reasonably be looked at as a stand-alone region, however: This state imports the vast majority of its food and energy, and is interdependent with the rest of the U. S. as well as the rest of the world. The recent tsunami in Japan and typhoon in the Philippines have awakened many businesses to the impact of a changing climate on global supply chains,⁵⁰ and ultra-dependent regions like Hawaii are by necessity very sensitive to these realities. Changing agricultural yields on the mainland may have a significant effect on Hawaii in terms of food cost and availability. Similarly, higher energy costs in the continental U.S. are likely to drive the cost of imported energy even higher for Hawaii. The state is pushing forward to diversify its energy resources and rely more on domestic renewable sources; however, most of these installations are along the vulnerable coastlines.

"I think we have to begin by recognizing the reality and severity of this threat to our economies, both United States and globally, and really to life on earth, more broadly as we know it. We also have to recognize that this problem needs to be dealt with now, we cannot wait because greenhouse gases in the atmosphere, once they're there, remain there for centuries so that every year is greater and more severe in terms of greenhouse gas emissions cumulatively than it has been the case the year before."

— Ask Senator James Inhofe, R-OK



If we were told—in any sphere—that we had at least a 90% chance of averting a disaster through changes we ourselves could make, wouldn't we take action?

— Risk Committee member Olympia Snowe²⁸

Taking a classic risk assessment approach to climate change in the U.S. leads to the inescapable conclusion that if we continue on our current climate path, the nation faces multiple risks across every region.

But risk assessment is not just about identifying risks and leaving it at that. Our research also shows that if we act today to move onto a different path, we can still avoid many of the worst impacts of climate change, particularly those related to extreme heat. We are fully capable of managing climate risk, just as we manage risk in many other areas of our economy and national security—but only if we start to change our business and public policy decisions today.

The Risky Business Project was not designed to dictate a single response to climate risk. We know that there will be a diversity of responses to our analysis depending on the particular risk tolerance of individual business and

policy actors, as well as their particular region or sector of the economy. But the Risk Committee does believe, based on this project's independent research and the significance of the climate risks it demonstrates, that it is time for all American business leaders and investors to get in the game and rise to the challenge of addressing climate change. The fact is that just as the investments and economic choices we made over the past several decades have increased our current vulnerability to climate change, so will the choices we make today determine what our nation looks like in 15 years, at mid-century, and by 2100.

In short, we have a choice whether we accept the climate risks laid out above or whether we get on another path.

This is not a problem for another day. The investments we make today—this week, this month, this year—will determine our economic future.

NEXT STEPS

There are three general areas of action that can help to minimize the risks U.S. businesses currently face from climate change:

BUSINESS ADAPTATION

Identify company business processes and assess their climate risk.

Some of the most important steps you can take to reduce the risk of climate change are to identify the business processes and assets that are most vulnerable to climate change. This includes assessing the physical risks to your operations, such as the impact of sea level rise, extreme weather, and drought on your facilities, equipment, and supply chain. It also includes assessing the transition risks to your business, such as the impact of new regulations, technology, and market preferences.

By identifying the climate risks to your business, you can develop a plan to address those risks. This may include measures such as relocating facilities, upgrading equipment, and diversifying your supply chain. It may also include measures such as improving energy efficiency, reducing greenhouse gas emissions, and developing a climate change strategy.

Full disclosure: Investors are increasingly demanding that companies disclose their climate risk. Performance may

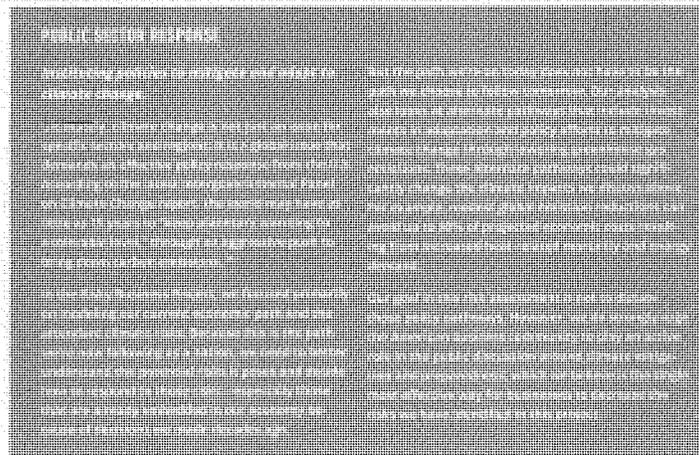
INVESTOR ADAPTATION

Addressing risk can improve your capital expenditures and business plans.

Addressing climate risk can improve your capital expenditures and business plans. This is because climate risk is a material risk that can affect the value of your company. By addressing climate risk, you can reduce the risk of financial loss and improve the long-term value of your company. This can help you attract investors and secure financing for your business.

Addressing climate risk can also improve your capital expenditures and business plans. This is because climate risk is a material risk that can affect the value of your company. By addressing climate risk, you can reduce the risk of financial loss and improve the long-term value of your company. This can help you attract investors and secure financing for your business.

NEXT STEPS



FROM RISK ASSESSMENT TO RISK MANAGEMENT: NEXT STEPS

With this project, we have attempted to provide a common language for how to think about climate risk—built upon a common language of risk that is already part of every serious business and investment decision we make today. If we have a common, serious, non-par-

tisan language describing the risks our nation may face from climate change, we can use it as the springboard for a serious, non-partisan discussion of the potential actions we can take to reduce those risks.



When Risk Committee member George Shultz was serving as President Reagan's Secretary of State in 1987, he urged the President to take action on that decade's hotly-contested scientific issue: the ozone layer. As Shultz later said in an interview with *Scientific American*, "Rather than go and confront the people who were doubting it and have a big argument with them, we'd say to them: Look, there must be, in the back of your mind, at least a little doubt. You might be wrong, so let's all get together on an insurance policy."³¹ That insurance policy became

the Montreal Protocol on Substances that Deplete the Ozone Layer, an international treaty still in effect to this day.

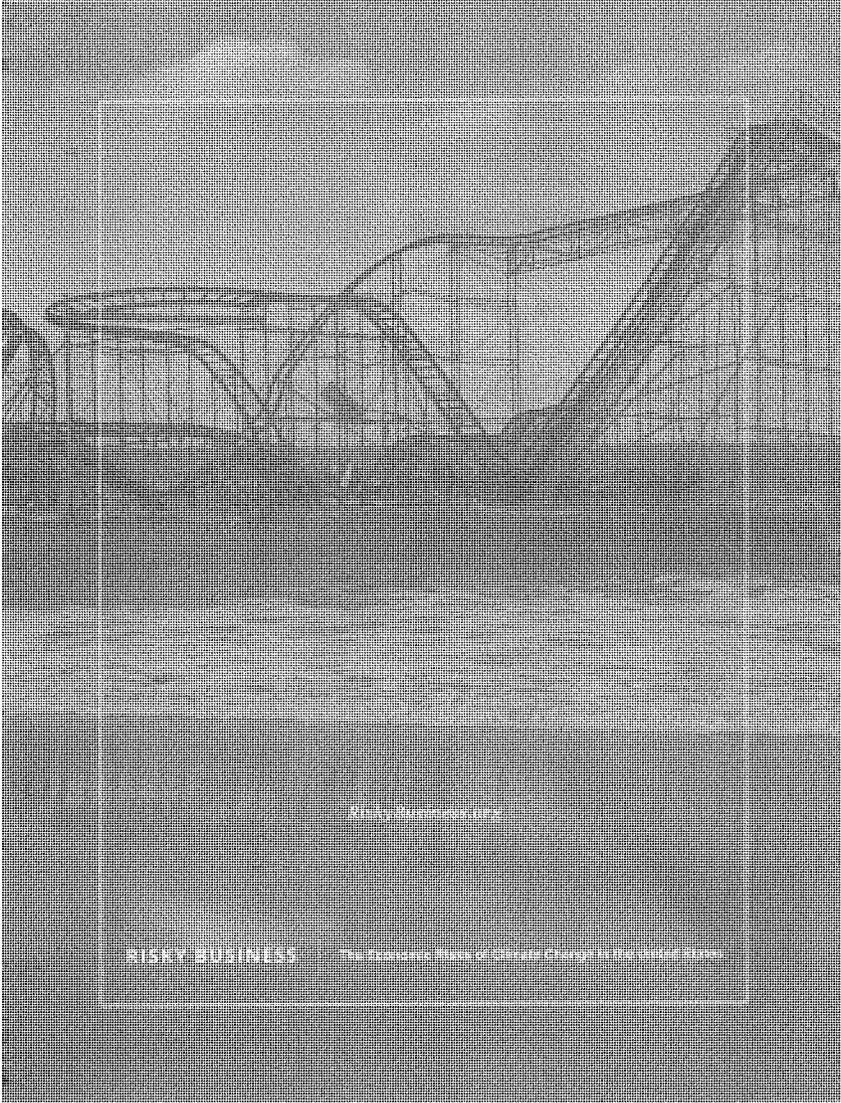
Our goal with the Risky Business Project is not to confront the doubters. Rather, it is to bring American business and government—doubters and believers alike—together to look squarely at the potential risks posed by climate change, and to consider whether it's time to take out an insurance policy of our own.

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EPA's Clean Power Plan: States' Tools for Reducing Costs and Increasing Benefits to Consumers

Analysis Group

**Paul Hibbard
Andrea Okie
Susan Tierney**

July 2014

Acknowledgments

This report evaluates the Clean Power Plan – proposed by the U.S. Environmental Protection Agency on June 2, 2014 – from the perspective of how it might impact consumers. The report examines how states’ plans to control carbon emissions may affect owners of affected power plants, other market participants in the electric industry, and, in turn, consumers of electricity. The paper examines one particular carbon-control program – the Northeast states’ Regional Greenhouse Gas Initiative – that has been in operation for several years, to illustrate how such carbon-control compliance costs and benefits have evolved over the initial years of that program. The paper also reviews the normal ratemaking practices and other regulatory policies in states across the country that are designed to mitigate rate impacts of investments and program costs affecting production and delivery of power to consumers. The goal of the Report is to reflect on recent experience to outline the tools states have to control costs and increase consumer benefits as they develop their plans.

This is an independent report by Analysis Group, supported by funding from the Energy Foundation and the Merck Family Fund. The authors wish to thank the foundations for their interest in electricity consumer issues and for their support of the analysis presented in this report. In addition, the authors thank Laurie Burt, of Laurie Burt LLC for effective and efficient project coordination, and Caroline Corbett, Lucy Wagner, and Anne Williams of Analysis Group for research assistance throughout the project.

The report, however, reflects the analysis and judgment of the authors only, and does not necessarily reflect the views of the Energy Foundation, the Merck Family Fund, or Laurie Burt LLC.

About Analysis Group

Analysis Group provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies. The firm has more than 600 professionals, with offices in Boston, Chicago, Dallas, Denver, Los Angeles, Menlo Park, New York, San Francisco, Washington, D.C., Montreal, and Beijing.

Analysis Group’s energy and environment practice area is distinguished by expertise in economics, finance, market modeling and analysis, regulatory issues, and public policy, as well as significant experience in environmental economics and energy infrastructure development. The practice has worked for a wide variety of clients including: energy producers, suppliers and consumers; utilities; regulatory commissions and other public agencies; tribal governments; power system operators; foundations; financial institutions; and start-up companies, among others.

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1. EXECUTIVE SUMMARY

On June 2, 2014, the United States Environmental Protection Agency (EPA) released proposed rules to reduce emissions of carbon dioxide (CO₂) from existing fossil power plants. EPA's "Clean Power Plan" would require significant reductions in CO₂ emissions from the power sector, while also providing each state the flexibility to determine its preferred way to comply with the new requirements.

EPA's analysis indicates that although there will be costs to comply with the Clean Power Plan, such costs will be much lower than the benefits to public health and to the overall economy from lower CO₂ and other air emissions.¹

Some observers² have contended that consumers will experience net costs because, in those observers' view, overall compliance costs will outweigh economic and other benefits. EPA's analysis indicates that customers will see slightly higher electricity rates in the near term but lower electricity bills over the long run with the Clean Power Plan in place.

Based on our own analysis and experience, we believe that the impacts on electricity rates from well-designed CO₂-pollution control programs will be modest in the near term, and can be accompanied by long-term benefits in the form of lower electricity bills and positive economic value to state and regional economies.

There are sound reasons to be confident that customers can and will benefit from states' plans to lower the carbon intensity of their electric systems. First, and foremost, states have a long track record of using various regulatory and other policy tools to encourage utility programs and investments that minimize the cost of electric service, consistent with the myriad of public policies (tax, environmental, reliability, labor, and other areas of policy) that affect the provision of electricity. State officials (including utility regulators) are keenly focused on protecting electricity customers and will keep that objective front and center as they determine how to reduce CO₂ emissions.

Second, under the proposed Clean Power Plan, states will have the flexibility, experience and tools to prepare and implement State Plans that fit their circumstances, minimize costs of compliance, and provide benefits to customers. States can each put together the elements of plans well-suited to their state, and they'll have the ability to phase in changes over the 2020-2029 period in ways that accommodate smooth transitions. Although states differ in many ways – including their electric systems, their regulatory culture, and their electric industry structure – all states have programs,

¹ EPA has estimated that by 2020, compliance costs for the Clean Power Plan will fall in a range of \$4.3 billion to \$7.5 billion (2011\$). For context, total expenditures on electricity in 2012 were \$363.7 billion (2012\$). (Source: Energy Information Administration (EIA) 861 database on electric revenues.) EPA's cost analysis tracks "the net change in the annualized cost of capital investment in new generating sources and heat rate improvements at coal steam facilities, the change in the ongoing costs of operating pollution controls, shifts between or amongst various fuels, demand-side energy efficiency measures, and other actions associated with compliance." EPA's analysis of benefits examines the effect of lower demand leading to lower costs to consumers, along with the expected economic, health, safety and environmental benefits of the rule. See EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (hereafter referred to as EPA RIA), June 2014, page ES-8, Table ES-10, and the Executive Summary more generally.

² See, e.g., Institute for 21st Century Energy (U.S. Chamber of Commerce), "Assessing the Impact of Potential New Carbon Regulations in the United States," May 2014.

policies and practices that will allow them to develop plans that align well with their different circumstances while still complying with the new CO₂ emission requirements. For example:

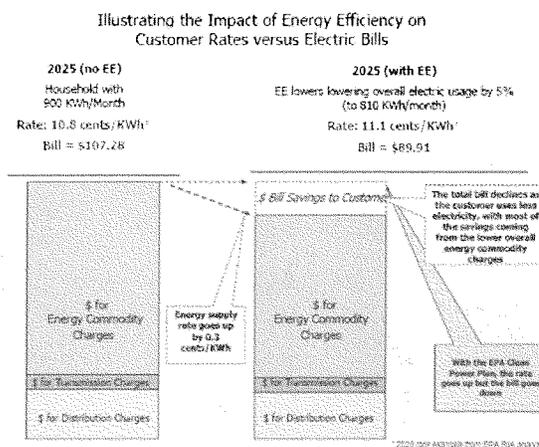
- States with vertically integrated utilities have mechanisms – including but not limited to integrated resource planning processes – for identifying least-cost compliance strategies. States have considerable experience and strong practical background in evaluating portfolios of supply and demand resources with costs and reliability in focus, and in encouraging long-term investments that minimize costs and maximize electricity consumer benefits.
- States with restructured electric industries can choose from a variety of market-based mechanisms that dovetail well with competitive retail and wholesale electric industry structures.
- Not surprisingly, in both areas, there will be continued opportunities in the future to use cost-effective energy-efficiency programs as part of states' CO₂ compliance strategies to help deliver significant benefits to customers and to local economies. Many states and utilities have deep experience in using energy efficiency as part of a least-cost utility resource plan or in competitive market contexts. Practices for design, implementation, administration, and evaluation of energy efficiency programs are readily transferable to states and utilities with less background in such programs. As the value of customer-side programs rises in the context of CO₂ compliance, states should expect to see more opportunities for cost-effective energy efficiency – and can use ratemaking tools to create incentives for utilities and others to pursue them.
- Additionally, many states are already introducing changes into their local utility systems to accommodate opportunities for customers to take actions – such as adopting energy efficient technologies in their buildings and operations – that will give customers the opportunity to be part of the solution in lowering carbon pollution from electricity production and use.

Third, market-based mechanisms offer unique opportunities to minimize costs while also reducing CO₂ emissions from existing power plants.

- States can implement such market-based programs within state boundaries. Moreover, states can work together – and with the stakeholders within each state – to develop and implement workable multi-state programs to control CO₂ emissions from existing power plants, in ways that fully preserve the rights of states in program design and administration. The EPA has not required states to develop their plans together, but the Clean Power Plan anticipates that many states may find it worthwhile to do so, in light of the way that electric systems and electrical resources are commonly shared across state boundaries.
- Such multi-state, market-based mechanisms to control CO₂ emissions can respect the practicalities of reliable electric system operations, and can be seamlessly integrated into both traditionally regulated and competitive electric industry settings.
- Pricing carbon – and this is likely true whether through a market-based mechanism or alternative compliance mechanisms – will help send efficient signals for new investment in resources (like zero-carbon technologies such as renewables and nuclear power plants, and in deeper energy efficiency measures) and for shifting power system operations toward power plants with lower carbon emissions.
- Market-based mechanisms – like the Regional Greenhouse Gas Initiative (RGGI) or California's cap-and-trade program – can provide opportunities for states to capture the economic value of

CO₂ emission allowances, and direct those revenues for consumer and public benefit. For example, in states with restructured electricity markets, states may choose to rely on methods to move CO₂ emission allowances into the market that avoid windfalls to owners of power plants. For the RGGI states, this has been accomplished through auctioning of CO₂ allowances. In other states (whether they have a traditional utility structure or a restructured market), another competitively neutral way to provide public/consumer benefits would be to allocate allowances for free to electric distribution utilities, who then can sell them to power generators and capture the revenues for consumers.

- Based specifically on our detailed analysis of states' experience with RGGI and the design of a wide array of programs that insulate lower-income consumers, we believe that the impacts on electricity rates and bills from well-designed CO₂-pollution control programs will be modest in the near term, especially for low-income customers. (See figure as example of the difference between rates and bills.³)



Fourth, states are well equipped through long-standing utility ratemaking principles, practices and programs to help protect low-income customers when electricity costs increase. Such tools include discounted rates and arrearage management plans, dedicated funding for low-income energy-efficiency and weatherization programs, utility-driven charitable contribution programs, one-time emergency assistance programs, LIHEAP funding for heating and utility bill assistance, and disconnect/shut-off protection policies. Among the many states we found to be offering targeted energy efficiency programs for low-income customers are Colorado, Florida, Georgia, Illinois, Maine, Maryland, Michigan, Missouri, Montana, North Carolina, Ohio, and Texas.

In the end, the states are in control. State environmental, energy and utility-regulatory agencies will tailor compliance approaches to their individual circumstances, and in doing so will play a significant role in driving down and managing the costs of Clean Power Plan compliance through their plans.

³ The difference between electricity rates and electricity bills is an important one in the context of many potential compliance approaches. In our prior analysis of the RGGI program, we found that while RGGI program costs initially had an increasing effect on electricity rates, the impact of energy efficiency investments (using RGGI allowance revenues) significantly reduced commercial and residential electricity use, placing downward pressure on rates over time, and combined with lower consumption, tended to generate on average much lower electricity bills. See: Paul Hibbard, Susan Tierney, Andrea Okie, Pavel Darling, "The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States," November 15, 2011 (hereafter referred to as the AG RGGI Report).

Those State Implementation Plans (or simply State Plans) will define the set of actions that will work together to reduce emissions from fossil power plants. The components of the State Plans will affect compliance costs and collateral benefits. And states' regulatory and ratemaking policies can influence how compliance actions undertaken by owners of power plants and other actors translate into increases or decreases in electricity rates and bills to different types of consumers. We note that EPA's Clean Power Plan is quite different from the more typical federal air regulations affecting emissions from fossil power plants. Normally, owners of such plants are responsible for determining how to comply with regulations through investments, changes in operations, or – in some cases – a decision to retire a plant. Here, the states themselves may end up taking the actions to reduce emissions (e.g., through energy efficiency programs or appliance-efficiency standards or continued pursuit of renewable resources, none of which are necessarily operated or paid for by owners of fossil power plants). If included in a State Plan, such elements would affect the operations and costs of some fossil power plants, but would do so indirectly rather than through an action specifically undertaken by an owner of a plant subject to the EPA's rules. And in turn, such policies adopted by a state could affect overall compliance costs passed through to electricity consumers – as well as the character of the benefits they receive through state actions under the Clean Power Plan.

Our report explains the practical mechanics of how compliance costs tend to be passed through to electricity consumers in competitive and traditional electricity systems. We also draw on recent experience among existing carbon-control programs already in operation in some states to illustrate how program design and state ratemaking policies can influence the distribution of cost and benefit outcomes to consumers. The bottom line, in our view, is that states have the means to help ensure that compliance costs are as low as possible – and to provide benefits to local economies.

How should we think about compliance costs in this context? To start with, controlling and reducing CO₂ will tend to increase the cost of doing business for many owners of affected plants, whether compliance is achieved through investments to increase a plant's efficiency, or through controls on a plant's operations that reduce its output (and associated revenues), and/or through the purchase of CO₂ allowances in a cap-and-trade program. Changes in plant operations (e.g., lower output, lower revenues from power sales) could also result from other components of a State Plan, for example, if a state were to include energy efficiency programs or renewable energy requirements or measures to retain existing nuclear plants as part of the power supply. These latter actions could lower the amount of power produced overall at fossil-fuel power plants, and help to offset potential costs associated with lowering the emissions from fossil-fuel power plants. States may choose to pursue these latter options because they could substantially help to lower the overall costs of compliance with the Clean Power Plan.

How could such compliance costs translate into impacts on consumers' electricity bills? This is a bit more complicated. In many parts of the U.S., there is not a straight line connecting the costs incurred by the owners of the power plants directly affected by EPA's Clean Power Plan, and the costs, benefits and state/regional economic impacts experienced by electricity consumers and other players in the electric industry. In fact, the relationship between power plant owners' compliance costs and consumers' prices will vary significantly, depending upon many factors (such as whether the local electric utility owns any power plants, or what things a state includes in its State Plan). For example:

- Approximately two-thirds of the nation's electricity customers live in regions where an independent grid operator runs a competitive power market. In these parts of the country –

including California, Texas, much of the Midcontinent region, the MidAtlantic area, and the Northeast – electricity customers pay prices based on the costs of the power plant operating on the margin in any hour, and thus do not necessarily reflect every dollar of compliance costs incurred by owners of all power plants. This results from the way that electricity prices arise in these markets (which we explain later in our report).

- Ten of the nation's states (California and the nine member states that participate in the Northeast/MidAtlantic region's RGGI program) already participate in a carbon cap-and-trade program, with compliance costs incurred by some – but not all – power producers already reflected in electricity prices.
- Across the country as a whole, approximately two-thirds of power is produced by electric utility companies (investor-owned utility companies, municipally owned utilities and electric cooperatives).⁴ In these contexts, state utility regulators and boards of public-power companies and cooperatives typically allow pass-through of costs and investments associated with environmental compliance activities. However, collection of these costs from customers usually requires least-cost planning processes and/or other cost-minimization steps as a condition of recovery, in order to maintain the incentives for efficient operations and investment, and to keep overall compliance costs low.

There clearly are a number of strategies that states can include in their State Plans to at least partially offset the impact of program costs on consumers. Experience demonstrates that some approaches can even generate net benefits to electricity customers and the larger state economy. An example of the latter is the RGGI states' auction of CO₂ allowances and use of the auction proceeds to support energy efficiency and customer bill credits; we have previously concluded in our detailed study of RGGI's first three years that it provided net benefits to customers and the economy of each participating state, and we update that prior analysis here to encompass over five years of experience with a CO₂ market-based trading program.⁵

There are other emission-credit trading approaches focused on consumer protection, cost mitigation or other objectives that could be adopted and implemented by states, such as the one proposed by the Clean Air Task Force (CATF). CATF's proposed mechanism would allow states "to mitigate retail electric rate impacts and protect all classes of electric ratepayers (industrial, commercial and residential) in all power markets by allowing for compensation to ratepayers...[and] to use a portion of the allowance allocations to compensate merchant coal generators for losses in asset value that may occur due to the program."⁶ In both of these approaches – one an actual program (RGGI), the other an alternative design – states' voluntary agreements to use a multi-state approach helps to keep

⁴ In more than half of the states, the local utility owns more than 70 percent of the power plant capacity. (Source: EIA 860 database for 2012.) Typically, state utility regulators in states with utilities that own power plants determine whether large capital investments at those plants are prudent, used and useful, and appropriate to be included in "just and reasonable" rates charged to customers. In many such states, the regulators review utilities' plans for capital investments at power plants are part of least-cost planning processes.

⁵ AG RGGI Report.

⁶ Conrad Schneider, "Power Switch: An Effective, Affordable Approach to Reducing Carbon Pollution from Existing Fossil-Fueled Power Plants," Clean Air Task Force, February, 2014, with accompanying technical analysis by Bruce Phillips, "Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions," The NorthBridge Group, February 2014 (together, hereafter referred to as CATF Proposal).

compliance costs low and mitigate impacts on affected entities. EPA's own benefit/cost analysis also supports this conclusion.⁷

Finally, creative approaches by states to address potential compliance costs, mitigate impacts on all consumers, and achieve various policy objectives will all be layered on top of a deep level of commitment and practice states have in managing electric industry costs. States have many decades of experience with electricity rate design, program benefit and cost allocation, and compliance program planning and implementation that will help guide an equitable distribution of program costs and benefits, while protecting lower-income customers.

We hope that our report provides states with ideas for how they might apply their experience and expertise in preparing State Plans to lower overall compliance costs and provide economic benefits to consumers and to the local economy. We assume that as states begin to consider what to include in their plans (as many states have already begun), they will do so by convening stakeholder processes to identify and weigh options and by assuring that personnel from different relevant state agencies are involved in those discussions. (The experience of Illinois and several other Midwest states are a few great examples.)

Although EPA's Clean Power Plan anticipates that a state's air regulatory agency will be the entity to present a state's plan to the EPA, our experience in state government⁸ informs us of the value of ensuring that all relevant state agencies (utility regulators, state energy offices, climate policy advisors, consumer protection branches, in addition to state environmental regulators) participate fully in the development of State Plans. Given the differences that exist among states in terms of the scope and depth of agency authorities, skills, and expertise, and given the fact that EPA's Clean Power Plan will lead to policies that directly and indirectly affect operations of the electric system and consumer prices, bringing more and different points of view to the task will likely improve the quality, costs and benefits of State Plans. State utility regulators, for example, will have a critical role in assuring that implementation of the EPA requirements occurs in a least-cost fashion and in assuring a fair allocation of costs and benefits of such actions. State energy offices often also have responsibility for many aspects of electricity use in appliances and buildings, and in managing renewable programs.



⁷ "The proposed emission guidelines provide states with options for establishing standards of performance in a manner that accommodates a diverse range of state approaches. The proposed guidelines would also allow states to collaborate and to demonstrate emission performance on a multi-state basis, in recognition of the fact that electricity is transmitted across state lines, and local measures often impact regional EGU CO2 emissions." EPA RIA, page ES-2, Table ES-4, and the Executive Summary more generally.

⁸ Paul Hibbard was recently Chairman of the Massachusetts Department of Public Utilities (DPU), and previously had worked in the state's air regulatory division. Sue Tierney previously served as Secretary of Environmental Affairs, Commissioner of the DPU, and senior economist at the energy office in Massachusetts, and was subsequently Assistant Secretary for Policy at the U.S. Department of Energy.

Our report describes our assessment of states' actual experience with RGGI, and of the larger body of ratemaking practices in states around the country through which regulators ensure fair and equitable rates to customers. In the latter, we examined a wide and diverse cross-section of states (covering half of the states in the U.S., as shown in the figure at the right), in order to point to the many tools available to states to manage the distribution of compliance costs and economic benefits among customers.

Clearly, State Plans approved by the EPA will create the framework for the industry's compliance with EPA's Clean Power Plan. How compliance plans are designed by the states will strongly affect the *magnitude* and *distribution* of costs and benefits among consumers, power plant owners, and the general economy. The regulatory practices for passing on costs to electricity consumers is also important, as it can influence the degree and allocation of **program** costs and benefits.

In the following sections, we discuss the analyses that allowed us to reach the conclusions noted above. Section 2 briefly summarizes EPA's proposed Clean Power Plan, and the role it anticipates for states in developing State Plans to control CO₂ emissions from existing power plants. We describe the wide range of compliance options available to states. In Section 3, we explain how different State Plan options may affect compliance costs, and how those costs may impact consumers' electricity rates and bills. Those impacts will vary across the country, due to several factors including: the different emission-reduction targets assigned to each state; the structure of the electric industry in the state (e.g., traditional utility-owned generation versus independent power production; vertically integrated utility operations versus wholesale competitive markets). We further highlight the importance of state program design on the economic benefits and costs of program implementation.

Section 4 reviews the experience of RGGI in the Northeast states, with RGGI being the long-running market-based CO₂ control program in the U.S. This discussion illustrates how a multi-state approach can operate seamlessly as part of the electric system, lead to efficient price signals affecting power plant dispatch, reduce emissions, and provide opportunities to control compliance costs and enhance benefits to consumers. Our review of RGGI's experience focuses on a recent economic analysis of the program, supplemented with a review of up-to-date data on continuing RGGI auctions and spending of allowance revenues.

Finally, in Section 5, we review state ratemaking practices and public policies that allow for fair cost recovery across all consumers, and for protecting low-income customers in particular. Appendix 1 provides more detail on EPA's proposed Clean Power Plan. Appendix 2 summarizes how RGGI states have used the proceeds from selling CO₂ allowances (e.g., to invest in energy efficiency programs, to provide a credit on customers' electricity bills and for other purposes including payments to the state's general fund). Appendix 3 compares state electricity revenues and spending on energy efficiency program by customer class, to illustrate how states can design those programs to support efficiency improvements for different types of customers. Appendix 4 provides case studies of electricity consumer-protection policies, to illustrate the tools currently in place in half of the states in the U.S.

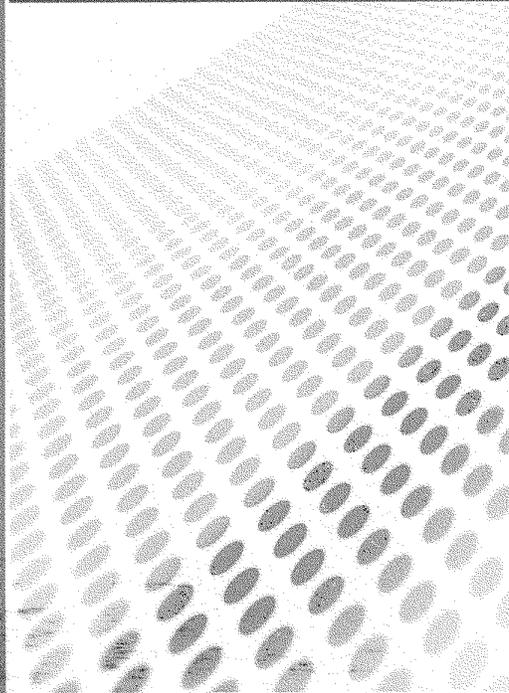
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IHS Energy

The Value of US Power Supply Diversity

July 2014

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The Value of US Power Supply Diversity

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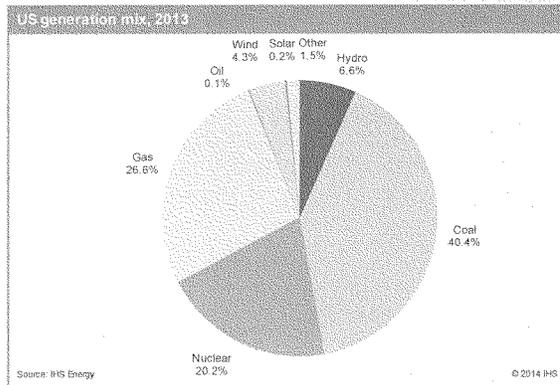
Executive summary

Engineering and economic analyses consistently show that an integration of different fuels and technologies produces the least-cost power production mix. Power production costs change because the input fuel costs—including for natural gas, oil, coal, and uranium—change over time. The inherent uncertainty around the future prices of these fuels translates into uncertainty regarding the cost to produce electricity, known as production cost risk. A diversified portfolio is the most cost-effective tool available to manage the inherent production cost risk involved in transforming primary energy fuels into electricity. In addition, a diverse power generation technology mix is essential to cost-effectively integrate intermittent renewable power resources into the power supply mix.

The current diversified portfolio of US power supply lowers the cost of generating electricity by more than \$93 billion per year, and halves the potential variability of monthly power bills compared to a less diverse supply. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power (see Figure ES-1). In this less diverse scenario, called the *reduced diversity case*, wind and solar power make up one-third of installed capacity (up from about 7% in the base case) and 22.5% of generation; hydroelectric power capacity decreases from about 6.6% to 5.3% and represents 3.8% of generation; and natural gas-fired power plants account for the remaining 61.7% of installed capacity and 73.7% of generation.

Power supply in the reduced diversity case increases average wholesale power prices by about 75% and retail power prices by 25%. Energy production costs are a larger percentage of industrial power prices, and many industrial consumers buy power in the wholesale power market. Thus a loss of power supply diversity will disproportionately affect the industrial sector. These higher electricity prices impact the broader US economy by forcing economic

FIGURE ES-1



adjustments in production and consumption. If the US power sector moved from its current diverse generation mix to the less diverse generating mix, power price impacts would reduce US GDP by nearly \$200 billion, lead to roughly one million fewer jobs, and reduce the typical household's annual disposable income by around \$2,100. These negative economic impacts are similar to an economic downturn. Additional potential negative impacts arise from reducing power supply diversity by accelerating the retirement of existing power plants before it is economic to do so. For example, a transition to the reduced diversity case within one decade would divert around \$730 billion of capital from more productive applications in the economy. The size of the economic impact from accelerating power plant turnover and reducing supply diversity depends on the deviation from the pace of change dictated by the underlying economics.

Maintaining and preserving a diverse US power supply mix is important to consumers for two reasons:

- Consumers reveal a strong preference for not paying more than they have to for reliable electricity.
- Consumers reveal preferences for some degree of predictability and stability in their monthly power bills.

The economic benefits of diverse power supply illustrate that the conventional wisdom of not putting all your eggs in one basket applies to power production in much the same way as it does to investing. This is the *portfolio effect*. In addition, diversity enables the flexibility to respond to dynamic fuel prices by substituting lower-cost resources for more expensive resources in the short run by adjusting the utilization of different types of generating capacity. This ability to move eggs from one basket to another to generate fuel cost savings is the *substitution effect*. Looking ahead, the portfolio and substitution effects remain critically important to managing fuel price risks because of the relative fuel price dynamics between coal and natural gas.

The shale gas revolution and restrictions on coal are driving an increased reliance on natural gas for power generation and provide strong economic benefits. However, this past winter demonstrated the danger of relying too heavily on any one fuel and that all fuels are subject to seasonal price fluctuations, price spikes, and deliverability and infrastructure constraints. The natural gas price spikes and deliverability challenges during the past winter were a jolt for a number of power systems that rely significantly on natural gas in the generation supply. These recent events demonstrated that natural gas deliverability remains a risk and natural gas prices continue to be hard to predict, prone to multiyear cycles, strongly seasonal, and capable of significant spikes. The root causes of these price dynamics are not going away anytime soon. The best available tool for managing uncertainty associated with any single fuel or technology is to maintain a diverse power supply portfolio.

Maintaining power supply diversity is widely supported—the idea of an all-of-the-above approach to the energy future is supported on both sides of the aisle in Congress and at both ends of Pennsylvania Avenue. Four decades of experience demonstrate the conclusion that government should not pick fuel or technology winners, but rather should create a level playing field to encourage the economic decisions that move the power sector toward the most cost-effective generation mix.

Maintaining a diverse power supply currently is threatened by three emerging trends:

- **Awareness.** The value of fuel diversity is often taken for granted because United States consumers inherited a diverse generation mix based on decisions from decades ago.

- **Energy policy misalignment.** Legislation and regulatory actions increasingly dictate or prohibit fuel and technology choices. The resulting power supply is increasingly at odds with the underlying engineering/economic principles of a cost-effective power supply mix.
- **Power market governance gridlock.** Market flaws produce wholesale power prices that are chronically too low to produce adequate cash flows to support and maintain investments in a cost-effective power generation mix. This “missing money” problem is not being addressed in a timely and effective way through the stakeholder governance processes found in most power markets. As a result, the loss of power supply diversity is accelerating because too many power plants are retiring before it is economic to do so. Consequently, they will be replaced with more costly sources of supply.

US power consumers are fortunate to have inherited a diverse power supply based on fuel and technology decisions made over past decades. Unfortunately, the current benefits of US power supply diversity are often taken for granted. This undervaluation of power supply diversity means there is no counterweight to current pressures moving the United States toward a future generation mix without any meaningful contribution from nuclear, coal, or oil and a diminished contribution from hydroelectric generation.¹

The United States needs to consider the consequences of a reduced diversity case involving no meaningful contribution from nuclear, coal-fired, or oil-fueled power plants, and significantly less hydroelectric power. A reduced diversity case presents a plausible future scenario in which the power supply mix has intermittent renewable power generation capacity of 5.5% solar, 27.5% wind, and 5.3% hydro and the remaining 61.7% of capacity is natural gas-fired power plants. Comparing the performance of current US power systems to this possible reduced diversity case provides insights into the current nature and value of diversity in the US generation mix.

IHS Energy assessed the current value of fuel diversity by using data on the US power sector for the three most recent years with sufficient available data: 2010 through 2012. IHS Energy employed its proprietary Power System Razor (Razor) Model to create a base case by closely approximating the actual interactions between power demand and supply in US power systems. Following this base case, the Razor Model was employed to simulate the reduced diversity case over the same time period. The differences between the base case and the reduced diversity case provide an estimate of the impact of the current US power supply fuel and technology diversity on the level and variance of power prices in the United States. These power sector outcomes were fed through to the IHS US macroeconomic model to quantify the broader economic impacts of the resulting higher and more varied power prices along with the shifts in capital deployment associated with premature retirements that accelerate the move to the reduced diversity case.

The difference between the base case and the reduced diversity case is a conservative estimate of the value of fuel diversity. The portfolio and substitution values would be greater over a longer analysis time frame because uncertainty and variation in costs typically increase over a longer time horizon. In addition, the estimate is conservative because it excludes indirect feedback effects from a higher risk premium in the reduced diversity power supplier cost of capital. This feedback is not present because the analysis alters only the generation capacity mix and holds all else constant. This indirect cost feedback would increase capital costs in this capital-intensive industry and magnify the economic impact of current trends to replace power plants before it is economic to do so by moving shifting capital away from applications with better risk-adjusted returns.

The United States is at a critical juncture because in the next decade the need for power supply to meet increased customer demands, replace retiring power plants, and satisfy policy targets will require fuel and

1. Oil-fired power plants account for about 4% of US capacity and 0.2% of US generation but can play a critical role in providing additional electricity when the system is under stress.

technology decisions for at least 150 gigawatts (GW)—about 15% of the installed generating capacity in the United States. However, current trends in energy policy could push that power plant turnover percentage to as much as one-third of installed capacity by 2030. The implication is clear: power supply decisions made in the next 10–15 years will significantly shape the US generation mix for decades to come.

The results of this study indicate seven key factors that will shape US power supply diversity in the years to come:

- **Energy policy development.** US policy heavily influences the US power supply mix. Implementing an all-of-the-above energy policy requires properly internalizing the value of fuel diversity.
- **Market structure.** Market flaws distort wholesale power prices downward and result in uneconomic retirement and replacement of existing cost-effective generation resources. This issue and any market structure changes to address it will significantly shape future power plant development.
- **Energy policy discourse.** Preserving the value of fuel diversity depends on public awareness and understanding. The extent and nature of public education regarding the value of power supply diversity may strongly influence public opinion.
- **Planning alignment.** Alignment of fuel and technology choices for power generation with engineering and economic principles is critical to efficient and reliable supply. There is no single fuel or technology of choice for power generation, and all forms of power production have economic, environmental, and reliability impacts.
- **Risk assessment.** To incorporate system considerations into plant-level decisions, prudent fuel price uncertainties must be used with probabilistic approaches to decision making.
- **Flexibility.** Flexibility and exemptions in rule making and implementation allow for the balancing of costs and benefits in power supply systems and may help preserve highly valuable diversity in systemwide decisions as well as on a small but impactful individual plant scale.
- **Scope.** Including fuel price risk and additional storage and transportation infrastructure costs is crucial when evaluating reduced diversity scenarios in comparison to the cost of maintaining and expanding fuel diversity.

The Value of US Power Supply Diversity

Overview

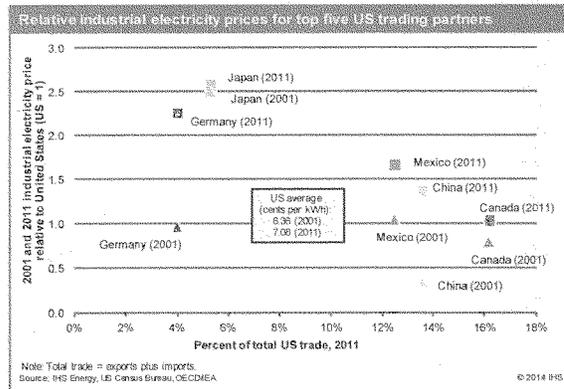
The power business is customer driven: consumers do not want to pay more than necessary for reliable power supply, and they want some stability and predictability in their monthly power bills. Giving consumers what they want requires employing a diverse mix of fuels and technologies in power production. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power. In this less diverse scenario, called the *reduced diversity case*, wind and solar power make up one-third of installed capacity (up from about 7% in the base case) and 22.5% of generation; hydroelectric power capacity decreases from about 6.6% to 5.3% and represents 3.8% of generation; and natural gas-fired power plants account for the remaining 61.7% of installed capacity and 73.7% of generation.

The current diverse US power supply reduces US consumer power bills by over \$93 billion per year compared to a reduced diversity case. In addition, the current diversified power generation mix mitigates exposure to the price fluctuations of any single fuel and, by doing so, cuts the potential variability of monthly power bills roughly in half.

Power prices influence overall economic performance. For example, since the recovery of the US economy began in the middle of 2009, manufacturing jobs in the 15 states with the lowest power prices increased by 3.3%, while in the 15 states with the highest power prices these jobs declined by 3.2%. This job impact affected the overall economic recovery. The average annual economic growth in the 15 states with the lowest industrial power prices was 0.6 percentage points higher than in the 15 states with the highest power prices.

Higher and more varied power prices can also impact international trade. In the past decade, the competitive position for US manufacturers improved thanks to lower relative energy costs, including the improving US relative price of electric power (see Figure 1). Although power prices are only one of a number of factors that influence competitive positions in the global economy, there are clear examples, such as Germany, where moving away from a cost-effective power generating mix is resulting in significant economic costs and a looming loss of competitiveness. German power prices increased rapidly over the past decade because Germany closed nuclear power plants before it was economic to do so and added too many wind and solar power resources too quickly into the generation mix. IHS estimates that Germany's net export losses

FIGURE 1



directly attributed to the electricity price differential totaled €52 billion for the six-year period from 2008 to 2013.²

A less diverse US power supply would make power prices higher and more varied and force a costly adjustment process for US consumers and businesses. The price increase associated with the reduced diversity case produces a serious setback to US economic activity. The value of goods and services would drop by nearly \$200 billion, approximately one million fewer jobs would be supported by the US economy, and the typical household's annual disposable income would go down by over \$2,100. These economic impacts take a few years to work through the economy as consumers and producers adjust to higher power prices. The eventual economic impacts are greater if current trends force the closure and replacement of power plants before it is economic to do so. Regardless of the replacement technology, it is uneconomic to close a power plant when the costs of continued operation are less than the cost of a required replacement. Premature power plant turnover imposes an additional cost burden by shifting capital away from more productive applications. A closure and replacement of all nuclear and coal-fired generating capacity in the next 10 years would involve roughly \$730 billion of investment. An opportunity cost exists in deploying capital to replace productive capital rather than expanding the productive capital base.

The United States currently faces a key challenge in that many stakeholders take the current benefits of power supply diversity for granted because they inherited diversity based on fuel and technology decisions made decades ago. There is no real opposition to the idea of an all-of-the-above energy policy in power supply. Yet, a combination of factors—tightening environmental regulations, depressed wholesale power prices, and unpopular opinions of coal, oil, nuclear, and hydroelectric power plants—are currently moving the United States down a path toward a significant reduction in power supply diversity. A lack of understanding of power supply diversity means momentum will continue to move the United States toward a future generation mix without any meaningful contribution from nuclear, coal, or oil, and a diminishing contribution from hydroelectric generation.

The United States is at a critical juncture because power plant fuel and technology decisions being made today will affect the US power supply mix for decades to come. These decisions need to be grounded in engineering, economic, and risk management principles that underpin a cost-effective electric power sector. Comparing the performance of the current generation mix to results of the reduced diversity case provides key insights into the current nature and value of diversity. An assessment and quantification of the value of power supply diversity will help achieve a more cost-effective evolution of US power supply in the years ahead.

Generation diversity: A cornerstone of cost-effective power supply

If power consumers are to receive the reliable and cost-effective power supply they want, then cost-effective power production requires an alignment of power supply to power demand. Engineering, economic, and risk management assessments consistently show that an integration of fuels and technologies produces the least-cost power production mix. A cost-effective mix involves integrating nondispatchable power supply with dispatchable base-load, cycling, and peaking technologies. This cost-effective generating mix sets the metrics for cost-effective demand-side management too. Integrating cost-effective power demand management capabilities with supply options requires balancing the costs of reducing or shifting power demand with the incremental cost of increasing power supply. Appendix A reviews the principles of engineering, economics, and risk management that lead to the conclusion that cost-effective power supply requires fuel and technological diversity.

² See the IHS study *A More Competitive Energielandschaft: Securing Germany's Global Competitiveness in a New Energy World*, March 2014.

The underlying principles of cost-effective power supply produce five key insights:

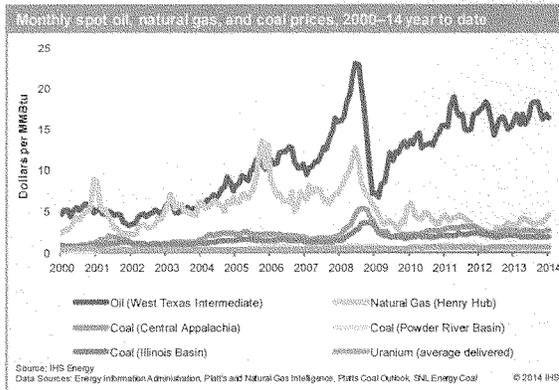
- There is no single fuel or technology of choice for power generation. Reliably and efficiently supplying consumers with the amounts of electricity they want when they want it requires a diverse generation mix.
- A cost-effective generation mix involves diversity but does not involve maximizing diversity by equalizing generation shares from all available supply options.
- A cost-effective mix of fuel and technologies for any power system is sensitive to the uncertainties surrounding the level and pattern of consumer power demands as well as the cost and performance of alternative power generating technologies and, in particular, the delivered fuel prices.
- A cost-effective generating mix will differ from one power system to the next because of differences in aggregate consumer demand patterns as well as in the cost and performance of available generating options.
- The best type of capacity to add to any generation portfolio depends on what types of capacity are already in the mix.

Power production cost fluctuations reflect inherent fuel price uncertainties

Power consumers reveal preferences for some degree of predictability and stability in their monthly power bills. These consumer preferences present a challenge on the power supply side because the costs of transforming primary energy—including natural gas, oil, coal, and uranium—into electric power is inherently risky. Experience shows that the prices of these fuel inputs to the power sector are difficult to anticipate because these prices move in multiyear cycles and fluctuate seasonally (see Figure 2). In addition, this past winter showed that dramatic price spikes occur when natural gas delivery systems are pushed to capacity (see Figure 3).

The recent volatility in the delivered price of natural gas to the US Northeast power systems demonstrates the value of fuel diversity. During this past winter, colder-than-normal weather created greater consumer demand for natural gas and electricity to heat homes and businesses. The combined impact on natural gas demand strained the capability of pipeline systems to deliver natural gas in the desired quantity and pressure. Natural gas prices soared, reflecting the market forces allocating available gas to the highest valued end uses. At some points in time, price allocation was

FIGURE 2



not enough and additional natural gas was not available at any price, even to power plants holding firm supply contracts.

As high as the natural gas price spikes reached, and as severe as the natural gas deliverability constraints were, things could have been worse. Although oil-fired power provided only 0.35% of generation in the Northeast in 2012, this slice of power supply diversity provided an important natural gas supply system relief valve. The oil-fired power plants and the dual-fueled oil- and natural gas-fired power plants were able to use liquid fuels to generate 12% of the New England power supply during the seven days starting 22 January 2014 (see Figure 4). This oil-fired generation offset the equivalent of 327,000 megawatt-hours (MWh) of natural gas-fired generation and thus relieved the natural gas delivery system of about 140 million cubic feet per day of natural gas deliveries. This fuel diversity provided the equivalent to a 6% expansion of the daily delivery capability of the existing natural gas pipeline system.

The lesson from this past winter was that a small amount of oil-fired generation in the supply mix proved to be highly valuable to the Northeast energy sector despite its production costs and emission rates. Many of these oil-fired power plants are old and relatively inefficient at converting liquid fuel to power. However, this relative inefficiency does not impose a great penalty because these power plants need to run very infrequently to provide a safety valve to natural gas deliverability. Similarly, these units have emissions rates well above those achievable with the best available technology, but the absolute amount of emissions and environmental impacts are small because their utilization rates are so low. Although the going forward costs and the environmental impacts are relatively small, the continued operation of these oil-fired power plants is at risk from tightening environmental regulations.

FIGURE 3

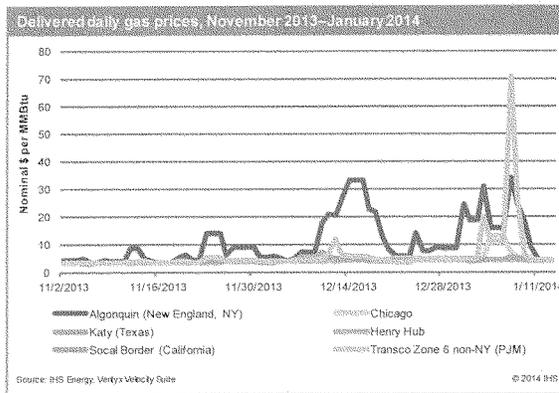
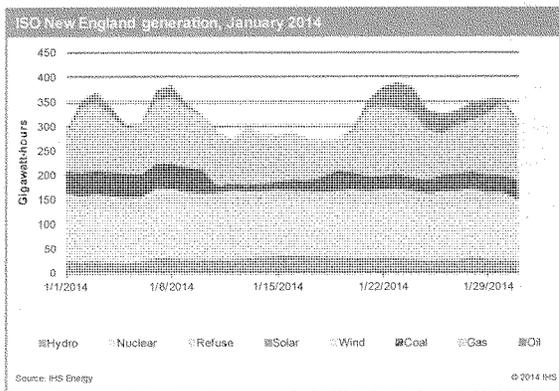


FIGURE 4



Oil-fired power plants were not the only alternative to natural gas-fired generation this past winter. Coal played a major role. As the *New York Times* reported on 10 March 2014, 89% of American Electric Power Company, Inc.'s 5,573 megawatts (MW) of coal-fired power plants slated for retirement in 2015 owing to tightening environmental regulations were needed to keep the lights on during the cold snap this past winter in PJM.³

The critical role fuel diversity played during the recent polar vortex affected power systems that serve over 40 million US electric consumers and almost one-third of power supply. This widespread exposure to natural gas price and deliverability risks is becoming increasingly important because the share of natural gas in the US power mix continues to expand. The natural gas-fired share of power generation increased from 16% to 27% between 2000 and 2013. Twelve years ago, natural gas-fired generating capacity surpassed coal-fired capacity to represent the largest fuel share in the US installed generating mix. Currently, natural gas-fired power plants account for 40% of the US installed capacity mix.

The increasing dependence on natural gas for power generation is not an accident. The innovation of shale gas that began over a decade ago made this fuel more abundant and lowered both its actual and expected price. But the development of shale gas did not change the factors that make natural gas prices cyclical, volatile, and hard to forecast accurately.

Factors driving natural gas price dynamics include

- Recognition and adjustment lags to market conditions
- Over- and under-reactions to market developments
- Linkages to global markets through possible future liquefied natural gas (LNG) trade
- Misalignments and lags between natural gas demand trends, supply expansions, and pipeline investments
- “Black swan” events—infrequent but high-impact events such as the polar vortex

Natural gas price movements in the shale gas era illustrate the impact of recognition and adjustment lags to changing market conditions. Looking back, natural gas industry observers were slow to recognize the full commercialization potential and magnitude of the impact that shale gas would have on US natural gas supply. Although well stimulation technologies date back to the 1940s, today's shale gas technologies essentially began with the innovative efforts of George Mitchell in the Barnett resource base near Fort Worth, Texas, during the 1980s and 1990s. Mitchell Energy continued to experiment and innovate until eventually proving the economic viability of shale gas development. As a result, shale gas production expanded (see Figure 5).

Although shale gas had moved from its innovation phase to its commercialization phase, many in the oil and gas industry did not fully recognize what was happening even as US shale gas output doubled from 2002 to 2007 to reach 8% of US natural gas production. The belief that the United States was running out of natural gas persisted, and this recognition lag supported the continued investment of billions of dollars to expand LNG import facilities (see Figure 6).

3. *New York Times*. “Coal to the Rescue, But Maybe Not Next Winter.” Wald, Matthew L. 10 March 2014: http://www.nytimes.com/2014/03/11/business/energy-environment/coal-to-the-rescue-this-time.html?_r=0, retrieved 12 May 2014.

Eventually, evidence of a shale gas revolution became undeniable. However, recognition and adaptation lags continued. Productivity trends in natural gas-directed drilling rigs indicate that only about 400 gas-directed rigs are needed to keep natural gas demand and supply in balance over the long run. Yet operators in the natural gas industry did not fully anticipate this technological trend. Bullish price projections caused the US natural gas-directed rig count to rise from 690 to 1,600 rigs

FIGURE 5

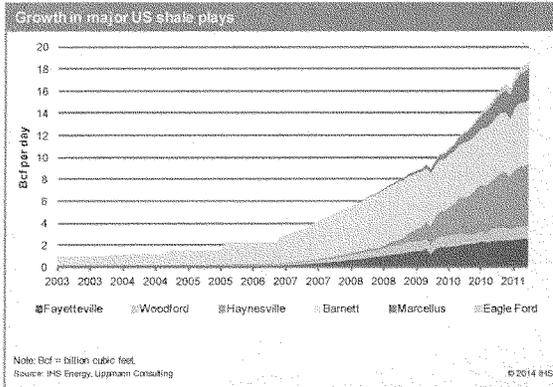
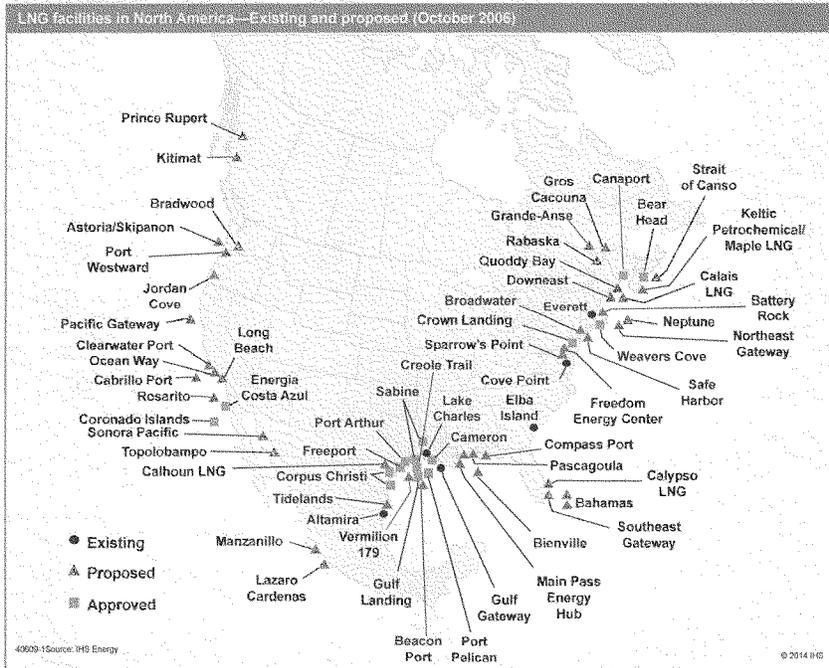


FIGURE 6



between 2002 and 2008. This level of drilling activity created a supply surplus that caused a precipitous decline of up to 85% in the Henry Hub natural gas price from 2008 to 2012. From the 2008 high count, the number of US natural gas-directed rigs dropped over fivefold to 310 by April 2014 (see Figure 7).

Natural gas investment activity also lagged market developments. During this time, the linkage between North American natural gas markets and global markets reversed from an investment hypothesis supporting an expansion of LNG import facilities, as shown in Figure 6, to an investment hypothesis involving the expansion of LNG export facilities (see Figure 8). At the same time, investment in natural gas pipelines and storage did not keep pace with the shifts in domestic demand, supply, and trade. This asymmetry created vulnerability to low frequency but high impact events, such as colder-than-normal winters

that expose gas deliverability constraints and launch record-setting delivered price spikes, as happened in the Northeast in the winters of 2012/13 and 2013/14.

The Northeast delivered natural gas price spikes translated directly into dramatic power production cost run-ups. During the winter of 2013/14, natural gas prices delivered to the New York and PJM power system border hit \$140 per MMBtu (at Transco Zone 6, 21 January 2014) and pushed natural gas-fired power production costs up 25-fold from typical levels and well beyond the \$1,000 per MWh hourly wholesale power price cap in New York and PJM. This forced the New York Independent System Operator (NYISO) to allow exemptions to market price caps. The Federal Energy Regulatory Commission granted an emergency request to lift wholesale power price caps in PJM and New York. Lifting these price caps kept the lights on but also produced price shocks to 30% of the US power sector receiving monthly power bills in these power systems. The impact moved the 12-month electricity price index (a component of the consumer price index) in the Northeast up 12.7%—the largest 12-month jump in eight years.

The New York Mercantile Exchange (NYMEX) futures contract price strip illustrates how difficult it is to anticipate natural gas price movements. Figure 9 shows the price dynamics over the shale gas era and periodic examples of the NYMEX futures price expectations. The NYMEX future price error pattern indicates a bias toward expecting future natural gas prices to look like those of the recent past. Although these futures prices are often used as an indicator of future natural gas price movements, they have nonetheless proven to be a poor predictor.

The complex drivers of natural gas price dynamics continue to apply in the shale gas era. Prudent planning requires recognition that natural gas price movements remain hard to forecast, affected by multiyear

FIGURE 7

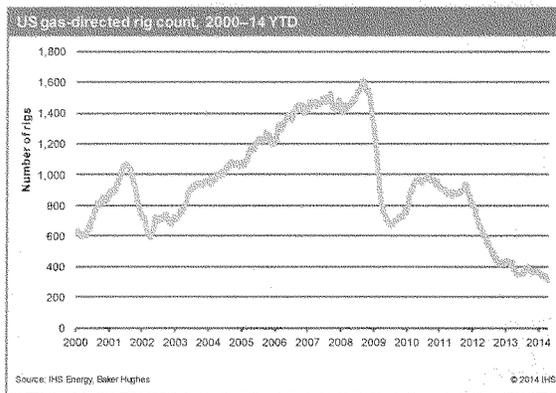
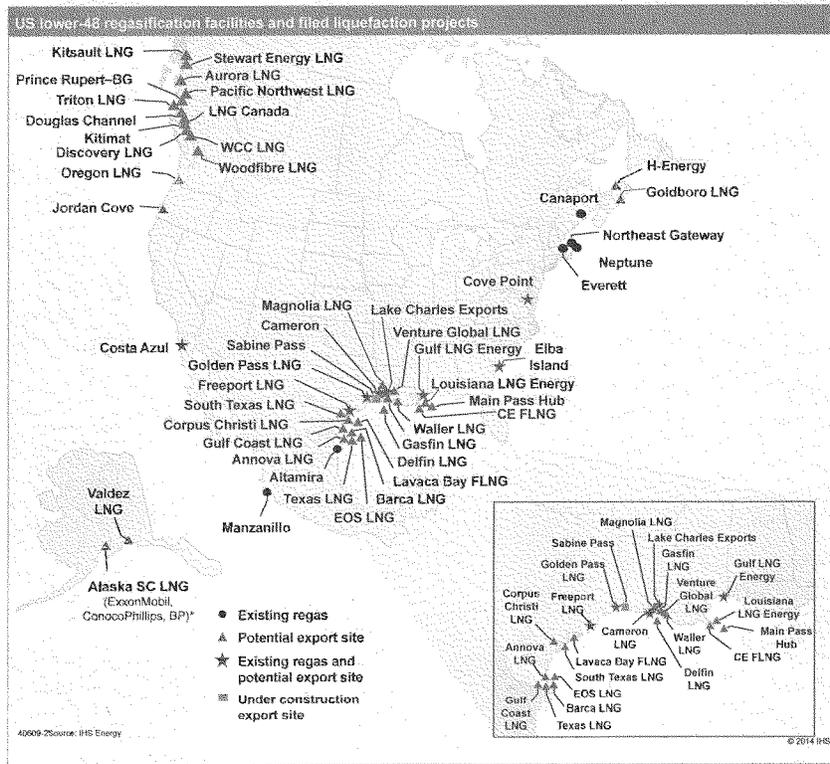


FIGURE 8



investment cycles that lag market developments, subject to seasonality, and capable of severe short-run price volatility.

Natural gas price cycles during the shale gas era and the recent extreme volatility in natural gas prices are clear evidence that the benefits of increased natural gas use for power generation need to be balanced against the costs of natural gas's less predictable and more variable production costs and fuel availability.

The natural gas-fired generation share is second only to the coal-fired generation share. One of the primary reasons that fuel diversity is so valuable is because natural gas prices and coal prices do not move together.

Significant variation exists in the price of natural gas relative to the price of coal delivered to US power generators (see Figure 10). The dynamics of the relative price of natural gas to coal are important because

relative prices routinely change which power plants provide the most cost-effective source of additional power supply at any point in time.

The relative prices of natural gas to coal prior to the shale gas revolution did not trigger as much cost savings from fuel substitution as the current relative prices do. From 2003 to 2007 the price of natural gas was four times higher than the price of coal on a Btu basis. Under these relative price conditions, small changes in fuel prices did not alter the position of coal-fired generation as the lower-cost resource for power generation. The shale gas revolution brought gas prices to a more competitive level and changed the traditional relative relationship between gas and coal generation. As Table 1 shows, the 2013 dispatch cost to produce electricity at the typical US natural gas-fired power plant was equivalent to the dispatch cost at the typical US coal-fired power plant with a delivered natural gas price of \$3.35 per MMBtu, about 1.39 times the delivered price of coal. Current price changes move the relative price of natural gas to coal around this average equivalency level and create more generation substitution than has historically occurred.

The average equivalency level triggers cost savings from substitution within the generation mix. Current relative prices frequently move above and below this critical relative price level. Consequently, slight movements in either coal or natural gas prices can have a big impact on which generation resource provides the most cost-effective source of generation at any given point in time.

Coal price dynamics differ from natural gas price movements. The drivers of coal price dynamics include rail and waterborne price shifts, changes in coal inventory levels, and mine closures and openings. In addition, international coal trade significantly influences some coal prices. For example, when gas prices

FIGURE 9

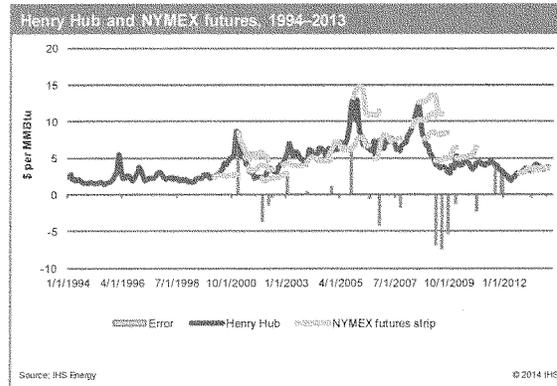
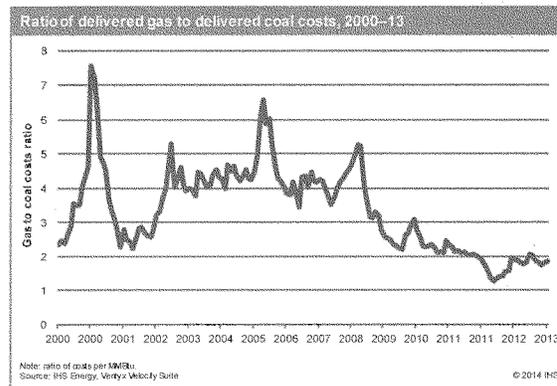


FIGURE 10



began to fall in 2008–12, the natural gas displacement of coal in power generation caused Appalachian coal prices also to drop. However, the coal price drop was slower and less severe than the concurrent natural gas price drop because of the offsetting increase in demand for coal exports, particularly for coal exports, particularly for metallurgical coal. Linkages to global coal market prices were significant even though only about one-quarter of Appalachian coal production was involved in international trade. The implication is that as global trade expands, the influence of international trade on domestic fuel prices may strengthen.

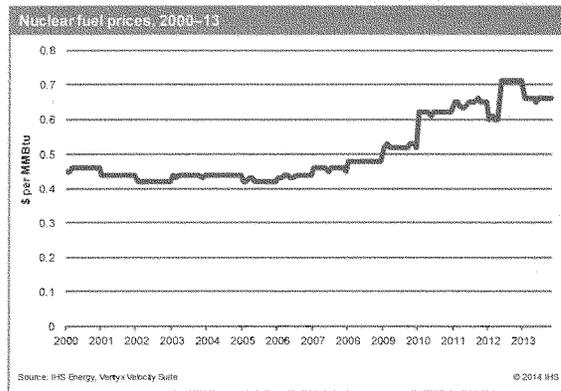
Nuclear fuel prices are also dynamic, and are different from fossil fuel prices in two ways (see Figure 11). Nuclear fuel cost is a relatively smaller portion of a nuclear plant's overall cost per kilowatt-hour. Also nuclear fuel prices have a different set of drivers. The primary drivers of nuclear fuel price movements include uranium prices, enrichment costs, and geopolitical changes in nuclear trade. These drivers produce price dynamics dissimilar to those of either natural gas or coal. As a result, nuclear fuel price movements are not strongly correlated to fossil fuel price movements.

TABLE 1

Typical generating units	Typical coal unit	Typical CCGT unit
Size, MW	218	348
Heat rate, Btu/kWh	10,552	7,599
Fuel cost, \$/MMBtu	\$2.41	\$4.46
Fuel cost, \$/MWh	\$25.43	\$33.89
Variable O&M, \$/MWh	\$4.70	\$3.50
Lbs SO ₂ /MWh (with wet FGD)	1.18	0
SO ₂ allowance price, \$/ton	70	70
Lbs NO _x /MWh	0.74	0.35
NO _x allowance price, \$/ton	252	252
SO ₂ , NO _x emissions cost, \$/MWh	0.13	0.02
Short-run marginal cost, \$/MWh	\$30.26	\$37.41
Break-even fuel price, \$/MMBtu	\$2.41	\$3.35

Note: kWh = kilowatt-hour(s); O&M = operation and maintenance (costs); SO₂ = sulfur dioxide; NO_x = nitrogen oxides; CCGT = combined-cycle gas turbine.
Source: IHS Energy

FIGURE 11



Diversity: The portfolio effect

A diverse fuel and technology portfolio is a cornerstone for an effective power production risk management strategy. If prices for alternative fuels moved together, there would be little value in diversity. But relative power production costs from alternative fuels or technologies are unrelated and inherently unstable. As a result, the portfolio effect in power generation exists because fuel prices do not move together, and thus changes in one fuel price can offset changes in another. The portfolio effect of power generation fuel diversity is significant because the movements of fuel prices are so out of sync with one another.

The “correlation coefficient” is a statistical measure of the degree to which fuel price changes are related to each other. A correlation coefficient close to zero indicates no similarity in price movements. Correlation coefficients above 0.5 are considered strong correlations, and values above 0.9 are considered very strong correlations. Power production input fuel price changes (natural gas, coal, and nuclear) are not highly correlated and consequently create the basis for a portfolio approach to fuel price risk management (see Table 2).

TABLE 2

Delivered monthly fuel price correlations, 2000–13	
Coal/natural gas	0.01
Natural gas/nuclear	(0.35)
Coal/nuclear	0.85

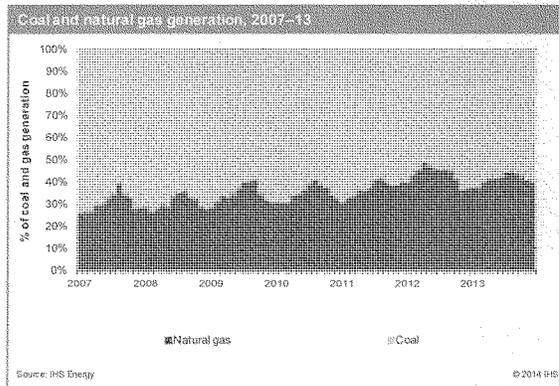
Source: IHS Energy

Diversity: The substitution effect

A varied portfolio mitigates power production cost risk because fuel diversity provides the flexibility to substitute one source of power for another in response to relative fuel price changes. Therefore, being able to substitute between alternative generation resources reduces the overall variation in production costs.

Substitution benefits have proven to be substantial. In the past five years, monthly generation shares for natural gas-fired generation were as high as 33% and as low as 19%. Similarly, monthly generation shares for coal-fired generation were as high as 50% and as low as 34%. The swings were driven primarily by a cost-effective alignment of fuels and technologies to consumer demand patterns and alterations of capacity utilization rates in response to changing relative fuel costs. Generation shares shifted toward natural gas-fired generation when relative prices favored natural gas and shifted toward coal-fired generation when relative prices favored coal. Figure 12 shows the recent flexibility in the utilization share tradeoffs between only coal-fired and natural gas-fired generation in the United States.

FIGURE 12



Diversity benefits differ by technology

All types of generating fuels and technologies can provide the first dimension of risk management—the *portfolio effect*. However, only some types of fuels and technologies can provide the second dimension of risk management—the *substitution effect*. Power plants need to be dispatchable to provide the substitution

effect in a diverse portfolio. As a result, the benefits of expanding installed capacity diversity by adding nondispatchable resources such as wind and solar generating technologies are less than the equivalent expansion of power capacity diversity with dispatchable power plants such as biomass, conventional fossil-fueled power plants, reservoir hydro, and nuclear power plants. Therefore, not all diversity in the capacity mix provides equal benefits.

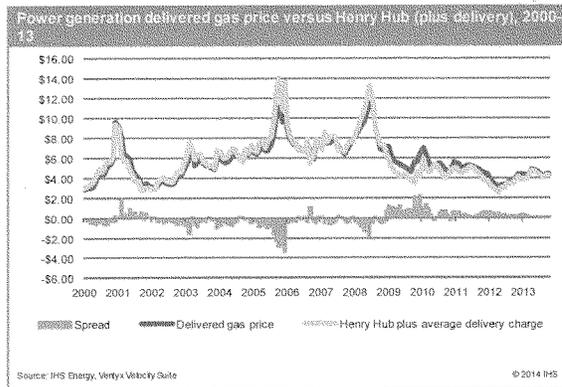
Diversity is the best available power cost risk management tool

A diverse portfolio is the best available tool for power generation cost risk management. Other risk management tools such as fuel contracts and financial derivatives complement fuel and technological diversity in power generation but fall far short of providing a cost-effective substitute for power supply diversity.

Contracts are tools available to manage power production cost risk. These tools include short-run contracts, including NYMEX futures contracts, as well as long-term contracts spanning a decade or more. Power generators have traditionally covered some portion of fuel needs with contracts to reduce the variance of delivered fuel costs. To do this, generators balance the benefits of using contracts or financial derivatives against the costs. With such assessment, only a small percentage of natural gas purchases are under long-term contracts or hedged in the futures markets. Consequently, the natural gas futures market is only liquid (has many buyers and sellers) for a few years out.

The degree of risk management provided by contracts is observed in the difference between the reported delivered price of natural gas to power generators and the spot market price plus a typical delivery charge. Contract prices along with spot purchases combine to determine the reported delivered price of natural gas to power generators. Delivered prices are typically about 12% higher than the Henry Hub spot price owing to transport, storage, and distribution costs, so this percentage may be used to approximate a delivery charge. Figure 13 compares the Henry Hub spot price plus this typical delivery charge to the reported delivered price of natural gas to power producers.

FIGURE 13



A comparison of the realized delivered price to the spot price plus a delivery charge shows the impact of contracting on the delivered price pattern. Natural gas contracts provided some protection from spot price highs and thus reduced some variation of natural gas prices compared to the spot market price plus transportation. Over the past 10 years, contracting reduced the monthly variation (the standard deviation) in the delivered price of natural gas to the power sector by 24% compared to the variation in the spot price

plus delivery charges at the Henry Hub. Although fuel contracts are part of a cost-effective risk management strategy, the cost/benefit trade-offs of using contracts limit the application of these tools in a cost-effective risk management strategy.

Using a contract to lock into volumes at fixed or indexed prices involves risks and costs. Contracting for fuel creates volume risk. A buyer of a contract is taking on an obligation to purchase a given amount of fuel, at a given price, and at a future point in time. From a power generator's perspective, the variations in aggregate power consumer demand and relative prices to alternative generating sources make predicting the amount of fuel needed at any future point in time difficult. This difficulty increases the further out in time the contracted fuel delivery date. If a buyer ends up with too much or too little fuel at a future point in time, then the buyer must sell or buy at the spot market price at that time.

Contracting for fuel creates price risk. A buyer of a fuel contract locks into a price at a future point in time. When the contract delivery date arrives, the spot market price for the fuel likely differs from the contract price. If the contract price ends up higher than the spot market price, then the contract provided price certainty but also created a fuel cost that turned out to be more expensive than the alternative of spot market purchases. Conversely, if the spot market price turns out to be above the contract price, then the buyer has realized a fuel cost savings.

Past price relationships also illustrate the potential for gains and losses from contracting for natural gas in an uncertain price environment. When the spot market price at Henry Hub increased faster than expected, volumes contracted at the previously lower expected price produced a gain. For example, in June 2008 the delivered cost of natural gas was below that of the spot market. Conversely, when natural gas prices fell faster than anticipated, volumes contracted at the previously higher expected price produced a loss. For example in June 2012, the delivered cost of natural gas was above that of the spot market purchases.

The combination of volume and price risk in fuel contracting makes buying fuel under contract a speculative activity, capable of generating gains and losses depending on how closely contract prices align with spot market prices. Therefore, cost-effective risk management requires power generators to balance the benefits of gains from contracting for fuel volumes and prices against the risk of losses.

Managing fuel price risk through contracts does not always involve the physical delivery of the fuel. In particular, a futures contract is typically settled before physical delivery takes place, and thus is referred to as a financial rather than a physical hedge to fuel price uncertainty. For example, NYMEX provides a standard contract for buyers and sellers to transact for set amounts of natural gas capable of being delivered at one of many liquid trading hubs at a certain price and a certain date in the future. Since the value of a futures contract depends on the expected future price in the spot market, these futures contracts are derivatives of the physical natural gas spot market.

The potential losses facing a fuel buyer that employs financial derivatives create a risk management cost. Sellers require that buyers set aside funds as collateral to insure that potential losses can be covered. Market regulators want these guarantees in place as well in order to manage the stability of the marketplace. Recently, as part of reforms aimed at improving the stability of the financial derivatives markets, the Dodd-Frank Act increased these collateral requirements and thus the cost of employing financial derivatives.

Outside of financial derivatives, fuel deliverability is an important consideration in evaluating power cost risk management. Currently, natural gas pipeline expansion requires long-term contracts to finance projects. Looking ahead, the fastest growing segment of US natural gas demand is the power sector and, as described earlier, this sector infrequently enters into long-term natural gas supply contracts that would finance new pipelines. Consequently, pipeline expansions are not likely to stay in sync with power generation natural gas demand trends.

The prospect of continued periodic misalignments between natural gas deliverability and natural gas demand makes price spikes a likely feature of the future power business landscape. The nominal volume of long-term fuel contracts and the costs and benefits of entering into such contracts limit the cost-effective substitution of contracts for portfolio diversity. Therefore, maintaining or expanding fuel diversity remains a competitive alternative to natural gas infrastructure expansion.

Striking a balance between the costs and benefits of fuel contracting makes this risk management tool an important complement to a diverse generation portfolio but does not indicate that it could provide a cost-effective substitute for power supply diversity.

A starting point taken for granted

US power consumers benefit from the diverse power supply mix shown in Figure 14. Simply inheriting this diverse generation mix based on fuel and technology decisions made decades ago makes it easy for current power stakeholders to take the benefits for granted. This underappreciation of power supply diversity creates an energy policy challenge because if the value of fuel and technology diversity continues to be taken for granted, then the current political and regulatory process is not likely to properly take it into account when crafting legislation or setting regulations.

As a result, the United States may move down a path toward a less diverse power supply without consumers realizing the value of power supply diversity until it is gone. For example, if the US power sector had been all natural gas-fired during the shale gas era to date, the average fuel cost for power would have been over twice as high, and month-to-month power bill variation (standard deviation) would have been three times greater (see Table 3). This estimate itself is conservative because the additional demand from power generation would have likely put significant upward pressure on gas prices.

FIGURE 14

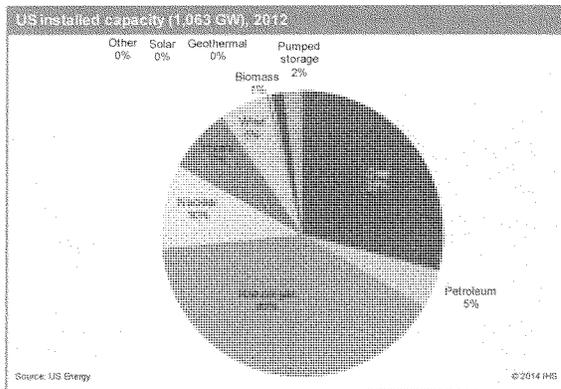


TABLE 3

	Henry Hub	All power sector fuel costs
Average	5.09	2.29
Maximum	11.02	4.20
Minimum	2.46	1.21
Standard deviation	1.63	0.55

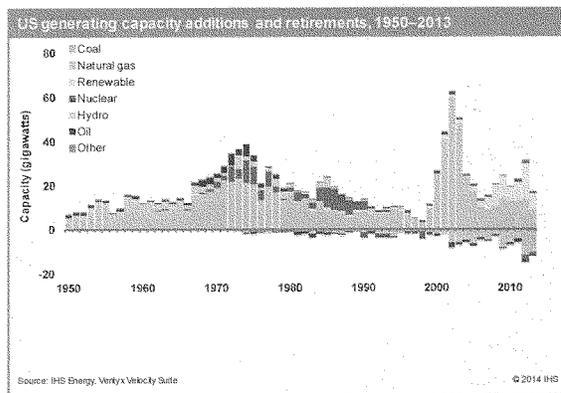
Note: Converted the Henry Hub dollar per MMBtu price to cents per kWh using the average reported heat rate for all operating natural gas plants in the respective month.
Data source: Ventyx Velocity Suite.
Source: IHS Energy.

Trends in the US generation mix

The current diverse fuel and technology mix in US power supply did not come about by accident. The US generation mix evolved over many decades and reflects the fuel and technology decisions made long ago for power plants that typically operate for 30 to 50 years or more. Consequently, once a fuel and technology choice is made, the power system must live with the consequences—whatever they are—for decades.

US power supply does not evolve smoothly. The generation mix changes owing to the pace of power plant retirements, the error in forecasting power demand, price trends and other developments in the energy markets, and the impacts of public policy initiatives. All three of these factors unfold unevenly over time. The current diverse generation mix evolved from multiyear cycles of capacity additions that were typically dominated by a particular fuel and technology (see Figure 15). The swings in fuel and technology choice do not indicate a lack of appreciation for diverse power supply. Instead, they show that given the size of the existing supply base, it takes a number of years of homogenous supply additions to move the overall supply mix a small proportion. Therefore, altering the overall mix slightly required a number of years of adjustment.

FIGURE 15



The uneven historical pattern of capacity additions is important because the future pattern of retirements will tend to reflect the previous pattern of additions as similarly aged assets reach the end of their useful lives. For example, current retirements are disproportionately reducing the coal and nuclear shares in the capacity mix, reflecting the composition of power plants added in the 1960s through 1980s. Current power plant retirements are about 12,000 MW per year and are moving the annual pace of retirements in the next decade to 1.5 times the rate of the past decade.

Power plant retirements typically need to be replaced because electricity consumption continues to increase. Although power demand increases are slowing compared to historical trends and compared to the growth rate of GDP, the annual rate of change nevertheless remains positive. US power demand is expected to increase between 1.0% and 2.5% each year in the decade ahead, averaging 1.5%.

The expected pace of US power demand growth reflects a number of trends. First, US electric efficiency has been improving for over two decades. Most appliances and machinery have useful lives of many years. As technology improves, these end uses get more efficient. Therefore, overall efficiency typically increases as appliances and machinery wear out and are replaced. On the other hand, the number of electric end uses keeps expanding and the end-use penetration rates keep increasing owing to advances in digital and communication technologies that both increase capability and lower costs. These trends in existing technology turnover

and new technology adoption produce a steady rate of change in electric end-use efficiency (see Figure 16).

Underlying trends in power demand are often masked by the influences of variations in the weather and the business cycle. For example, US electric output in first quarter 2014 was over 4% greater than in the same period one year ago owing in part to the influence of the polar vortex. Therefore, trend rates need to compare power consumption increases either between points in time with similar weather conditions or on a weather-normalized basis. Similarly, power demand trends can be misleading if compared without taking the business cycle into account. Figure 17 shows the trend rate of growth in power use from the previous business cycle peak to peak and trough to trough. Overall, power consumption increased by between 0.5 and 0.6 of the rate of increase in GDP. Looking ahead, GDP is expected to increase on average 2.5% annually through 2025 and thus is likely to produce a trend rate of electric consumption of around 1.5% annually. This US power demand growth rate creates a need for about 9 GW of new power supply per year, for a total of 1,140 GW by 2025.

FIGURE 16

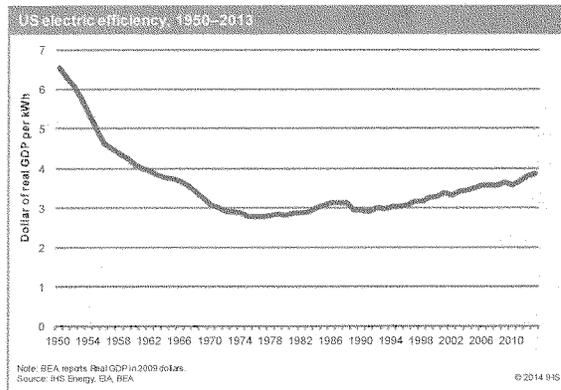
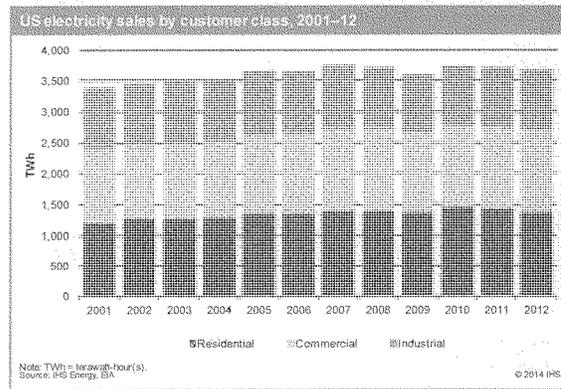


FIGURE 17



Annual power supply additions do not typically unfold simultaneously with demand increases. Historically, changes in power supply are much more pronounced than the changes in power demand. This uneven pace of change in the capacity mix reflects planning uncertainty regarding future power demand and a slow adjustment process for power supply development to forecast errors.

Future electric demand is uncertain. Figure 18 shows a sequence of power industry forecasts of future demand compared to the actual demand. The pattern of forecast errors indicates that electric demand forecasts are slow to adjust to actual conditions: overforecasts tend to be followed by overforecasts, and

underforecasts tend to be followed by underforecasts.

Forecasting uncertainty presents a challenge because fuel and technology decisions must be made years in advance of consumer demand to accommodate the time requirements for siting, permitting, and constructing new sources of power supply. As a result, the regional power systems are subject to momentum in power plant addition activity that results in capacity surpluses and shortages. Adjustment to forecast overestimates is slow because when a surplus becomes evident, the capital

intensity of power plants creates an accumulating sunk-cost balance in the construction phase of power supply development. In this case, there is an economic incentive to finish constructing a power plant because the costs to finish are the relevant costs to balance against the benefits of completion. Conversely, if a shortage becomes evident, new peaking power plants take about a year to put into place under the best of circumstances. Consequently, the forecast error and this lagged adjustment process can produce a significant over/underinstallment of new capacity development versus need. These imbalances can require a decade or more to work off in the case of a capacity overbuild and at least a few years to shore up power supply in the case of a capacity shortage.

The pace and makeup of power plant additions are influenced by energy policies. The current installed capacity mix reflects impacts from the implementation of a number of past policy initiatives. Most importantly, 35 years ago energy security was a primary concern, and the energy policy response included the Fuel Use Act (1978) and the Public Utilities Regulatory Policy Act (1978). These policies limited the use of natural gas for power generation and encouraged utility construction of coal and nuclear generating resources as well as nonutility development of cogeneration. Public policy championed coal on energy security grounds—as a safe, reliable, domestic resource.

The influence of energy policy on power plant fuel and technology choice is dynamic. For example, as natural gas demand and supply conditions changed following the passage of the Fuel Use Act, the limits on natural gas use for power generation were eventually lifted in 1987. Whereas the Fuel Use Act banned a fuel and technology, other policy initiatives mandate power generation technologies. Energy policies designed to address the climate change challenge created renewable power portfolio requirements in 30 states (see Figure 19).

As states work to implement renewable generation portfolio standards, the complexity of power system operations becomes evident and triggers the need for renewable integration studies. These studies generally find that the costs to integrate intermittent power generation resources increase as the generation share of these resources increases. Some integration studies go so far as to identify the saturation point for wind resources based on their operational characteristics. A wind integration study commissioned by the

FIGURE 18

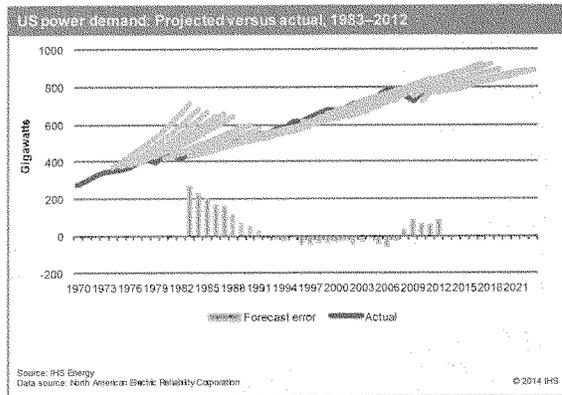
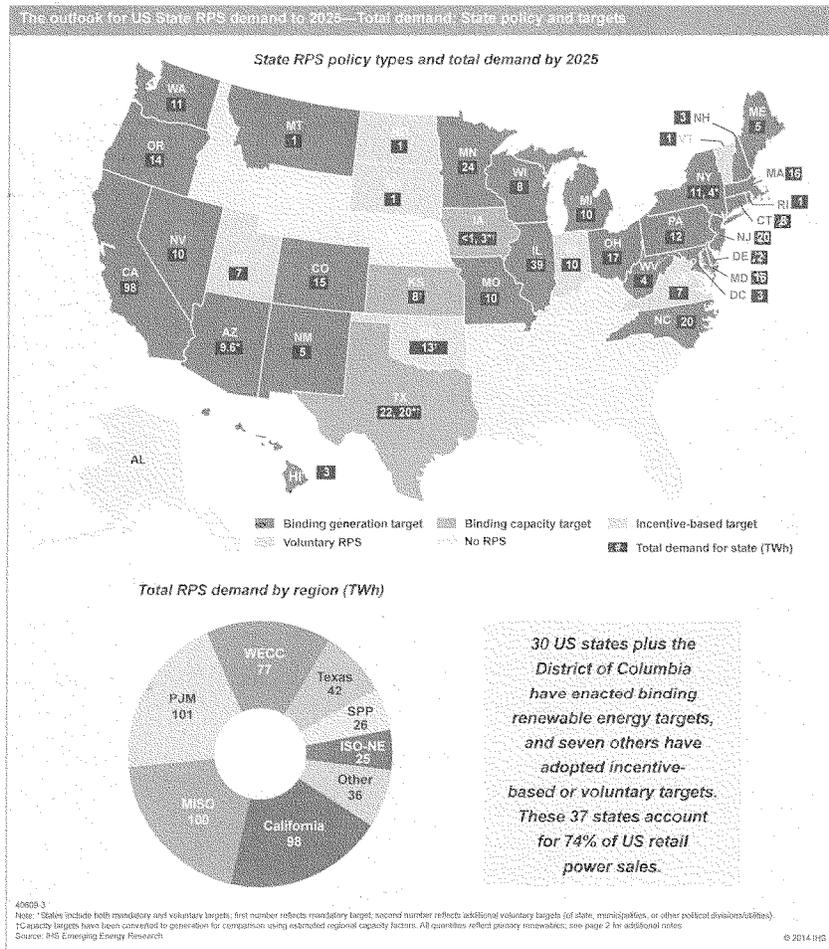


FIGURE 19

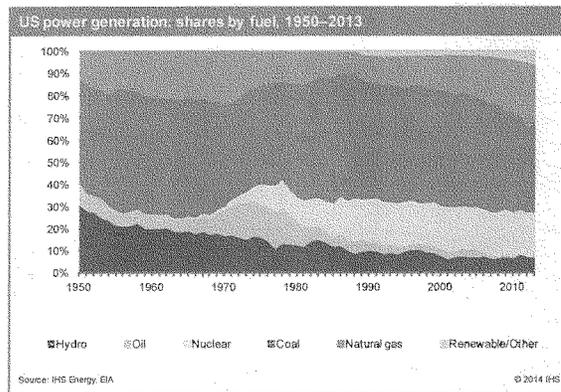


power system operator in New England estimated the saturation point for wind in the power system (24% generation share) as well as the additional resources that would be needed to integrate more wind resources.⁴ Similarly, a wind integration study by the power system operator in California found that problems were ahead for the California power system because the number of hours when too much wind generation was being put on the grid was increasing. The study noted higher costs were ahead as well because additional resources would be needed to integrate expected additional wind resources planned to meet the renewable portfolio requirements in place.⁵ Many of the impacts on the US generation mix from renewable power portfolio requirements are yet to come as higher generation or capacity share mandates become binding in many states in the next few years.

The United States is at a critical juncture because current trends in power plant retirements, demand and supply balances, and public policies are combining to accelerate change in the US generation mix,

as shown in Figure 20. In 2013, increases in demand, power plant retirements, and renewable mandates resulted in around 15,800 MW of capacity additions. In the decade ahead, these increasing needs will require power supply decisions amounting to 15% of the installed generating capacity in the United States. In addition, public policies are expected to increase the share of wind and solar generation, and forthcoming regulations from the Environmental Protection Agency (EPA) regarding conventional power plant emissions as well as greenhouse gases (GHG) could significantly increase power plant retirements and accelerate changes further. Altogether, changes in US generating capacity in the next two decades could account for more than one-third of installed capacity.

FIGURE 20



Threat to power generation diversity: Complacency

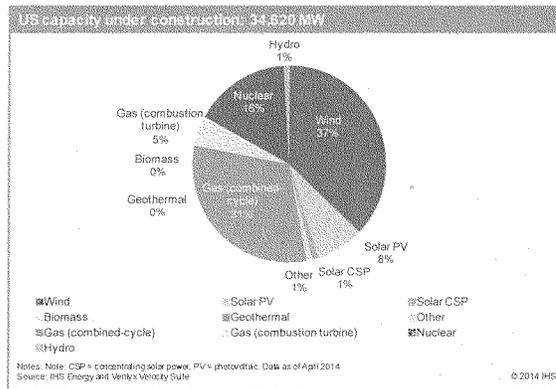
Threats to maintaining diversity in power production do not come from opposition to the idea itself, but rather from the complacency associated with simply taking diversity for granted. The familiar adage of not putting all your eggs in one basket is certainly aligned with the idea of an all-of-the-above energy policy. Four decades of experience demonstrates the conclusion that the government should not be picking fuel or technology winners, but rather should be setting up a level playing field to encourage competitive forces to move the power sector toward the most cost-effective generation mix. Nevertheless, in a striking contrast,

4. *New England Wind Integration Study* produced for ISO New England by GE Energy Applications and Systems Engineering, EnerNex Corporation, and AWS Truepower, 5 December 2010. Accessed 16 April 2014 (http://www.uwig.org/newis_es.pdf).

5. "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS." California ISO, 31 August 2010, downloaded from www.caiso.com/2804/2804d036401f0.pdf.

the value of fuel diversity to the end use consumer is not internalized in current power plant decision making. A 2013 review of over eighty integrated resource plans (IRPs) found that many reference fuel diversity but only a few of them refer to it as a risk, and none of them quantify the value of fuel diversity to incorporate it into the decision process.⁶ Additionally, environmental policy initiatives do not seem to accommodate diversity issues. Therefore, one power plant decision after another is revealing a de facto energy policy to move away from oil, coal, and nuclear generation and reduce hydroelectric capability, and instead build relatively low utilization wind and solar resources backed up by natural gas-fired generating units (see Figure 21).

FIGURE 21



Threat to power generation diversity: The “missing money”

Fuel diversity is threatened as well by the inability of power markets to evolve market rules and institutions to address the “missing money” problem in competitive power generator cash flows. The missing money problem in power markets is the latest manifestation of a long-standing problem in a number of industries, including railroads, airlines, and power, where competitive markets fail to balance demand and supply at market-clearing prices high enough to support the full cost of supply.

Power markets have a missing money problem because they do not have all of the necessary conditions to produce a textbook competitive marketplace. The textbook marketplace has suppliers who maximize their profits by expanding output up to the point where their short-run marginal cost (SRMC) of production equals the market-clearing price. This means that an aggregation of rival suppliers’ SRMC curves produces the market supply curve. If this market supply curve intersects the market demand curve at a price too low to support the full cost of new supply (long-run marginal cost [LRMC]), then suppliers will not expand productive capacity. Instead, they will meet increases in demand by adding more variable inputs to the production process with a fixed amount of capacity. However, doing so increases SRMC, and eventually the market-clearing price rises to the point where it covers the cost of expanding productive capacity. This produces the textbook market equilibrium where demand and supply are in balance at the unique point where market-clearing prices are equal to both SRMC and LRMC.

Several characteristics of the technologies that make up a cost-effective power supply create a persistent gap between SRMCs and LRMCs as production varies. As a result, market-clearing wholesale power prices are below the level needed to support the full cost of power supply when demand and supply are in balance with the desired level of reliability.⁷ Consequently, the stable textbook market equilibrium does not exist in an electric power marketplace.

6. See the IHS Energy Insight *Reading the Tea Leaves: Trends in the power industry's future plans*.

7. See the IHS Energy Private Report *Power Supply Cost Recovery: Bridging the missing money gap*.

A simple example of a competitive power market made up entirely of rival wind generators illustrates the missing money problem. The cost profile of wind turbine technologies comprises nearly exclusively upfront capital costs (LRMCs). SRMCs for wind technologies equal zero because the variable input to the power production process is wind, and this input is free. In a competitive market, if wind conditions allow for power production, then rival wind generators will be willing to take any price above zero to provide some contribution to recovering the upfront capital costs. If there is adequate supply to balance demand in a competitive marketplace, then rival wind suppliers will drive the market-clearing price to zero. This is not just a theoretical example. When power system conditions create wind-on-wind competition, then zero or negative market-clearing prices (reflecting the cost of losing the production tax credit) are typically observed. Wind generating technologies are a simple and extreme example of a power generating technology with a persistent gap between SRMCs and LRMCs. But this problem exists to some degree with other power generation technologies.

This technology-based market flaw means that periodic shortage-induced price spikes are the only way for market-clearing prices to close the gap between the SRMC and LRMC. This market outcome does not work because of the inherent contradiction—periodic shortages are needed to keep demand and supply in balance.

The missing money problem threatens cost-effective power supply because when market-clearing power prices are chronically too low to support new power plants, then lower expected cash flows at existing plants cause retirements before it is economic to do so, given replacement costs. It is cost effective to retire and replace a power plant only when its cost of continued operation becomes greater than the cost of replacement. Therefore, a market-clearing power price that reflects the full cost of new power supply is the appropriate economic signal for efficient power plant closure and replacement. Consequently, when this price signal is too low, power plant turnover accelerates and moves power supply toward the reduced diversity case.

“Missing money” and premature closing of nuclear power plants

The Kewaunee nuclear plant in Wisconsin is an example of a power plant retirement due to the missing money problem. Wholesale day-ahead power prices average about \$30 per MWh in the Midwest power marketplace. This market does not have a supply surplus, and recently the Midwest Independent System Operator (MISO), the institution that manages the wholesale market, announced that it expects to be 7,500 MW short of generating capacity in 2016.⁸ The current market-clearing power price must almost double to send an efficient price signal that supports development of a natural gas-fired combined-cycle power plant.

The Kewaunee power plant needs much less than the cost of a new plant, about \$54 per MWh, to cover the costs of continued operation. Kewaunee’s installed capacity was 574 MW, and the plant demonstrated effective performance since it began operation in 1974. The plant received Nuclear Regulatory Commission approval for life extension through 2033. Nevertheless, the persistent gap between market prices and new supply costs led Dominion Energy, the power plant’s owner, to the October 2012 decision to close the plant because of “low gas prices and large volumes of wind without a capacity market.”

Kewaunee is not an isolated case. Other nuclear power plants such as Vermont Yankee provide similar examples. Additionally, a significant number of coal-fired power plants are retiring well before it is economic to do so. For example, First Energy retired its Hatfield’s Ferry plant in Ohio on 9 October 2013. This is a large (1,700 MW) power plant with a \$33 per MWh variable cost of power production.⁹ The going-forward

8. Whieldon, Esther. “MISO-OMS survey of LSEs, generators finds resource shortfall remains likely in 2016.” SNL Energy, 6 December 2013. Accessed on 14 May 2014 <http://www.snl.com/InteractiveX/ArticleAbstract.aspx?id=26168778>. Note: LSE = load-serving entity.

9. Source: SNL Financial data for 2012 operations, accessed 5 May 2014. Available at <http://www.snl.com/InteractiveX/PlantProductionCostDetail.aspx?id=3604>.

costs involved some additional environmental retrofits, but the plant had already invested \$650 million to retrofit a scrubber just four years prior to the announced retirement.

Reducing diversity and increasing risk

Proposed EPA regulations on new power plants accommodate the carbon footprint of new natural gas-fired power plants but do not accommodate the carbon footprint of any new state-of-the-art conventional coal-fired power plants that do not have carbon capture and storage (CCS). Since the cost and performance of CCS technologies remain uneconomic, the United States is now on a path to eliminating coal-fired generation in US power supply expansion. This move toward a greatly reduced role for coal in power generation may accelerate because the EPA is now developing GHG emission standards for existing power plants that could tighten emissions enough to dramatically increase coal-fired power plant retirements.

The impact of a particular fuel or technology on fuel diversity depends on overall power system conditions. As a general rule, the benefits of fuel diversity from any source typically increase as its share in the portfolio decreases. Oil-fired generation illustrated this principle when it proved indispensable in New England in keeping electricity flowing this past winter. Despite only accounting for 0.2% of US generation, it provided a critical safety valve for natural gas deliverability during the polar vortex. Yet, these oil-fired power plants are not likely to survive the tightening environmental regulations across the next decade. The implication is clear: there is a much higher cost from losing this final 0.2% of oil in the generation mix compared to the cost of losing a small percentage of oil-fired generation back in 1978, when oil accounted for 17% of the US generation mix. Losing this final 0.2% of the generation mix will be relatively expensive because the alternative to meet infrequent surges in natural gas demand involves expanding natural gas storage and pipeline capacity in a region where geological constraints make it increasingly difficult to do so.

Public opinion is a powerful factor influencing the power generation mix. The loss of coal- or oil-fired power plants in the generation mix is often ignored or dismissed because of public opinion. Coal- or oil-fired power plants are generally viewed less favorably than wind and solar resources. In particular, labeling some sources of power as “clean energy” necessarily defines other power generating sources as “dirty energy.” This distinction makes many conventional power supply sources increasingly unpopular in the political process. Yet, all sources of power supply employed to meet customer needs have an environmental impact. For example, wind and solar resources require lots of land and must be integrated with conventional grid-based power supply to provide consumers with electricity when the wind is not blowing or the sun is not shining. Therefore, integrating these “clean energy” resources into a power system to meet consumer needs produces an environmental footprint, including a GHG emission rate. The arbitrary distinctions involved in “clean energy” are evident when comparing the emissions profiles of integrated wind and solar power production to that of nuclear power production. A simplistic and misleading distinction between power supply resources is a contributing factor to the loss of fuel diversity.

Edison International provides an example of the impact of public opinion. Antinuclear political pressures in California contributed to the decision in 2013 to prematurely close its San Onofre nuclear power plant. This closure created a need for replacement power supply that is more expensive, more risky, and more carbon intensive.

The going-forward costs of continued operation of the San Onofre nuclear plant were less than the cost of replacement power. Therefore, the closure and replacement of the San Onofre power plant made California power supply more expensive in a state that already has among the highest power costs in the nation. A study released in May 2014 by the Energy Institute at Haas at the University of California Berkeley estimated that closing the San Onofre nuclear power station increased the cost of electricity by \$350 million during the

first twelve months.¹⁰ This was a large change in power production costs, equivalent to a 13% increase in the total generation costs for the state.

Closing San Onofre makes California power costs more risky. California imports about 30% of its electricity supply. Prior to the closure, nuclear generation provided 18.3% of California generation in 2011, and the San Onofre nuclear units accounted for nearly half of that installed nuclear capacity. The Haas study found that imports increase with system demand but not much, likely owing to transmission constraints, grid limitations, and correlated demand across states. The results imply that the loss of the San Onofre power plant was primarily made up through the use of more expensive generation, as much as 75% of which was out-of-merit generation running to supply energy as well as voltage support. The report's analysis found that up to 25% of the lost San Onofre generation could have come from increased imports of power. The substitute power increases California consumers' exposure to the risks of fossil fuel price movements as well as the risks of low hydroelectric generation due to Western Interconnection drought cycles.

Closing San Onofre makes California power production more carbon intensive. Nuclear power production does not produce carbon dioxide (CO₂) emissions. These nuclear units were a major reason that the CO₂ intensity of California power production was around 0.5 pounds (lb) per kilowatt-hour (kWh). Replacement power coming from in-state natural gas-fired power plants has associated emissions of about 0.9 lb per kWh. Replacement power coming from the rest of the Western Interconnection has associated emissions of 1.5 lb per kWh. Even additional wind and solar power sources in California with natural gas-fired power plants filling in and backing them up have a 0.7 lb per kWh emissions profile. The Haas study found that closing San Onofre caused carbon emissions to increase by an amount worth almost \$320 million, in addition to the \$350 million in increased electricity prices in the first year. In the big picture, California CO₂ emissions have not declined in the past decade, and the closure of the San Onofre nuclear units will negate the carbon abatement impacts of 20% of the state's current installed wind and solar power supply.

The path toward a less diverse power supply

The relative unpopularity of coal, oil, nuclear, and hydroelectric power plants (compared to renewables), combined with the missing money problem, tightening environmental regulations, and a lack of public awareness of the value of fuel diversity create the potential for the United States to move down a path toward a significant reduction in power supply diversity. Within a couple of decades, the US generation mix could have the following capacity characteristics:

- No meaningful nuclear power supply share
- No meaningful coal-fired power supply share
- No meaningful oil-fired power supply share
- Hydroelectric capacity in the United States reduced by 20%, from 6.6% to 5.3% of installed capacity
- Renewables power supply shares at operational limits in power supply mix: 5.5% solar, 27.5% wind
- Natural gas-fired generation becoming the default option for the remaining US power supply of about 61.7%

10. http://ei.haas.berkeley.edu/pdf/working_papers/WP248.pdf, accessed 30 May 2014.

Comparing the performance of current diverse power supply to this reduced diversity case provides a basis for quantifying the current value of fuel and technology diversity in US power supply.

Quantifying the value of current power supply diversity

A number of metrics exist to compare and contrast the performance of power systems under different scenarios. Three power system performance metrics are relevant in judging the performance of alternative generation portfolios:

- SRMC of electric production (the basis for wholesale power prices)
- Average variable cost of electric production
- Production cost variability

IHS Energy chose a geographic scope for the diversity analyses at the interconnection level of US power systems. The United States has three power interconnections: Electric Reliability Council of Texas (ERCOT), Eastern, and Western. These interconnections define the bounds of the power supply network systems that coordinate the synchronous generation and delivery of alternating current electrical energy to match the profile of aggregate consumer demands in real time.

Analysis at the interconnection level is the minimum level of disaggregation needed to analyze the portfolio and substitution effects of a diverse fuel and technology generation mix. In particular, the substitution effect involves the ability to shift generation from one source of power supply to another. The degree of supply integration within an interconnection makes this possible, whereas the power transfer capability between interconnections does not. The degree of power demand and supply integration within these interconnections creates the incentive and capability to substitute lower-cost generation for higher-cost generation at any point in time. These competitive forces cause the incremental power generation cost-based wholesale power prices at various locations within each interconnection to move together. An average correlation coefficient of monthly average wholesale prices at major trading hubs within each interconnection is roughly 0.8, indicating a high degree of supply linkage within each interconnection.

IHS Energy assessed the current value of fuel diversity by using the most recently available data on the US power sector. Sufficient data were available for 2010 to 2012, given the varied reporting lags of US power system data.

IHS employed its Razor Model to simulate the interactions of demand and supply within each of these US power interconnections from 2010 to 2012. The 2010 to 2012 backcasting analysis created a base case of the current interactions between power demand and supply in US power systems. Appendix B describes the IHS Razor Model and reports the accuracy of this power system simulation tool to replicate the actual performance of these power systems. The high degree of predictive power produced by this model in the backcasting exercise establishes the credibility of using this analytical framework to quantify the impacts of more or less fuel and technology diversity. The macroeconomic impact analysis used the most recently available IHS simulation of the US economy (December 2013) as a base case.

Once this base case was in place, the Razor Model was employed to simulate an alternative case involving a less diverse generation mix. The current generation mix in each of the three interconnections—Eastern, Western, and ERCOT—were altered as follows to produce the reduced diversity case generation:

- The nuclear generating share went to zero.
- The coal-fired electric generating share went to zero.
- The hydroelectric generation share dropped to 3.8%.
- Intermittent wind and solar generation increased its combined base case generation share of about 2% to shares approximating the operational limits—24% in the East, 45% in the West, and 23% in ERCOT—resulting in an overall wind generation share of 21.0% and a solar generation share of 1.5%.
- Natural gas-fired generation provided the remaining generation share in each power system, ranging from about 55% in the West to over 75% in the East and ERCOT, for an overall share of nearly 74%.

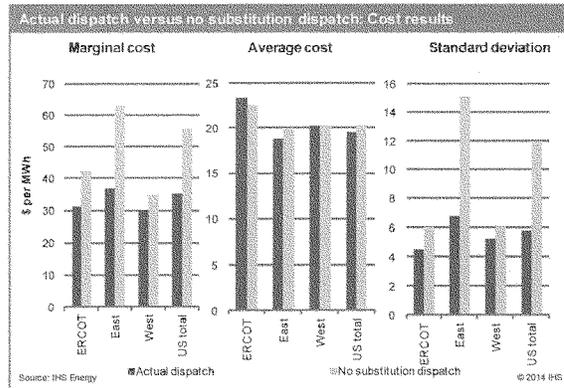
Differences between the performance metrics of the current diverse generating portfolio simulation and the reduced diversity case simulation provide an estimate for the current value of fuel diversity. The differences in the level and variance of power prices were fed through to the IHS US macroeconomic model to quantify the broader economic impacts of the higher and more varied power prices and shifts in capital deployment associated with the reduced diversity case.

Quantification of the impact of fuel diversity within the US power sector involved a two-step process. The first step quantifies the current value of the substitution effect enabled by a diverse power generating portfolio. The second step quantified the additional value created by the portfolio effect.

The value of the substitution effect

The first step alters the base case by holding relative fuel prices at the average level across 2010 to 2012. Doing this removes the opportunity to substitute back and forth between generation resources based on changes to the marginal cost of generation. This case maintains a portfolio effect but eliminates the substitution effect in power generation. The difference between this constant relative fuel price case and the base case provides an estimate of the current value of the substitution effect provided by the current diverse power generation fuel mix. The results show significantly higher fuel costs from a generation mix deprived of substitution based on fuel price changes. The substitution effects in the current diverse US power generating portfolio reduced the fuel cost for US power production by over \$2.8 billion per year. In just the three years of the base case, US power consumers realized nearly \$8.5 billion in fuel savings from the substitution effect. Figure 22 shows the results of this first step in the analysis for each interconnection and the United States as a whole.

FIGURE 22

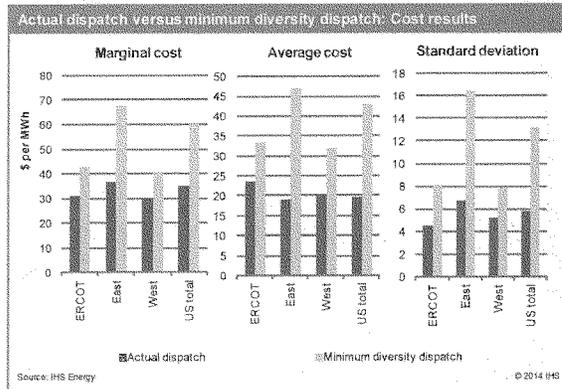


The value of the portfolio effect

The second step quantifies the portfolio value of the current generation mix. To measure this, the base case is altered by replacing the actual current generation mix with the less diverse generation mix. All else is held constant in this reduced diversity case, including the actual monthly fuel prices. Therefore, this reduced diversity simulation reduces the portfolio effect of diverse generation and allows any economic generation substitution to take place utilizing this less diverse capacity mix.

Figure 23 shows the performance metrics for each interconnection and the United States as a whole in the less diverse portfolio case compared to the base case.

FIGURE 23



The portfolio effect reduces not only costs, but also the variation in costs. This translates into a reduction in the typical monthly variation in consumers' power bills of between 25% and 30%.

The differences in average power production costs between the reduced diversity case and the current supply case indicate that fuel and technology diversity in the base case US generation mix provides power consumers with benefits of \$93 billion per year. This difference between the reduced diversity case and the base case includes both the substitution and portfolio effects. Using the results of step one allows separation of these two effects, as shown in Table 4.

Figures 24 and 25 show the progression from the base case to the reduced diversity case. The results indicate that the Eastern power interconnection has the most to lose from a less diverse power supply because it faces more significant increases in cost, price, and variability in moving from the base case to the reduced diversity case. The Eastern interconnection ends up with greater variation in part because its delivered fuel costs are more varied than in Texas or the West. In addition, the natural endowments of hydroelectric power in the Western interconnection generation mix continue to mitigate some of the fuel price risk even at a reduced generation share.

In the past three years, generation supply diversity reduced US power supply costs by \$93 billion per year, with the majority of the benefit coming from the portfolio effect. These estimates are conservative because they were made only across the recent past, 2010 to 2012. An evaluation over a longer period of history would show increased benefits from managing greater levels of fuel price risk.

The estimates of the current value of power supply diversity are conservative as well because they do not include the feedback effects of higher power cost variation on the cost of capital for power suppliers, as outlined in Appendix A. The analyses indicate that a power supplier with the production cost variation equal to the current US average would have a cost of capital 310 basis points lower than a power supplier

TABLE 4

Diversity cases cost results		Substitution effect	Portfolio effect	Total
ERCOT	Output (2011, TWh)	334	334	334
	Marginal cost increase (\$/MWh)	\$11.10	\$0.35	\$11.45
	Average cost increase (\$/MWh)	(\$0.91)	\$10.62	\$9.71
	Marginal cost increase split	97%	3%	100%
	Average cost increase split	-9%	109%	100%
	Marginal cost increase percentage	95.40%	1.10%	36.50%
	Average cost increase percentage	-3.90%	45.20%	41.40%
	Marginal cost increase (total)	\$3,708,970,647	\$116,702,120	\$3,825,672,967
	Average cost increase (total)	(\$302,604,000)	\$3,547,080,000	\$3,244,476,000
	Eastern interconnection	Output (2011, TWh)	2,916	2,916
Marginal cost increase (\$/MWh)		\$26.01	\$4.73	\$30.74
Average cost increase (\$/MWh)		\$1.10	\$26.92	\$29.02
Marginal cost increase split		85%	15%	100%
Average cost increase split		4%	96%	100%
Marginal cost increase percentage		70.70%	12.80%	63.50%
Average cost increase percentage		5.80%	142.70%	149.50%
Marginal cost increase (total)		\$75,840,639,098	\$13,791,489,884	\$89,632,128,981
Average cost increase (total)		\$3,207,600,000	\$78,498,720,000	\$81,706,320,000
Western interconnection		Output (2011, TWh)	728	728
	Marginal cost increase (\$/MWh)	\$4.94	\$5.27	\$10.21
	Average cost increase (\$/MWh)	(\$0.10)	\$11.67	\$11.57
	Marginal cost increase split	48%	52%	100%
	Average cost increase split	-1%	101%	100%
	Marginal cost increase percentage	16.50%	17.60%	34.10%
	Average cost increase percentage	-0.50%	57.50%	57.00%
	Marginal cost increase (total)	\$3,593,597,137	\$3,837,638,788	\$7,431,235,926
	Average cost increase (total)	(\$72,800,000)	\$8,495,760,000	\$8,422,960,000
	US total	Output (2011, TWh)	3,978	3,978
Marginal cost increase (\$/MWh)		\$20.90	\$4.46	\$25.36
Average cost increase (\$/MWh)		\$0.71	\$22.76	\$23.47
Marginal cost increase split		82%	18%	100%
Average cost increase split		3%	97%	100%
Marginal cost increase percentage		59.50%	12.70%	72.20%
Average cost increase percentage		3.60%	116.70%	120.30%
Marginal cost increase (total)	\$83,143,207,082	\$17,745,830,792	\$100,889,037,874	
Average cost increase (total)	\$2,832,195,000	\$90,841,560,000	\$93,373,755,000	

Source: IHS Energy

with the production cost variation associated with the generation mix of the reduced diversity case. Since 14% of total power costs are returned to capital, this difference accounts for 1-3% of the overall cost of electricity. This cost-of-capital effect can have a magnified impact on overall costs if more capital has to be deployed with an acceleration of power plant closures and replacements from the pace that reflects underlying economics.

The cost of accelerating change in the generation mix

Current trends in public policies and flawed power market outcomes can trigger power plant retirements before the end of a power plant's economic life. When this happens, the closure creates cost impacts beyond the level and volatility of power production costs because it requires shifting capital away from a productive alternative use and toward a replacement power plant investment.

All existing power plants are economic to close and replace at some point in the future. The economic life of a power plant ends when the expected costs of continued operation exceed the cost of replacement. When

this happens, the most cost-effective replacement power resource depends on the current capacity mix and what type of addition creates the greatest overall benefit—including the impact on the total cost of power and the management of power production cost risk.

Figure 26 shows the current distribution of the net present value (NPV) of the going-forward costs for the existing US coal-fired generation fleet on a cents per MWh basis in relation to the levelized NPV of replacement power on a per MWh basis.

As the distribution of coal-fired power plant going-forward costs indicates, there is a significant difference between the going-forward costs and the replacement costs for the majority of plants. As a result, a substantial cost exists to accelerate the turnover of coal-fired power plants in the capacity mix. For example, closing coal-fired power plants and replacing them as quickly as possible with natural gas-fired power plants would impose a turnover cost of around \$500 billion.

Figure 27 shows the going-forward costs of the existing US nuclear power plant fleet. As with the coal units, there is currently a high cost associated with premature closure. As a point of comparison, closing all existing nuclear power plants and replacing them as quickly as possible with natural gas-fired power plants would impose a turnover cost of around \$230 billion. Unlike the coal fleet, where a nominal amount of older capacity has a going-forward cost that exceeds the expected levelized cost of replacement, none of the US nuclear capacity is currently more expensive than the lowest of projected replacement costs.

Closing a power plant and replacing it before its time means incurring additional capital costs. The average depreciation rate of capital in the United States is 8.3%. This implies that the average economic life of a

FIGURE 24

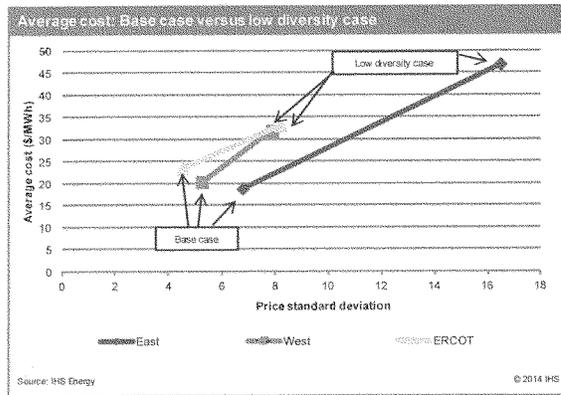
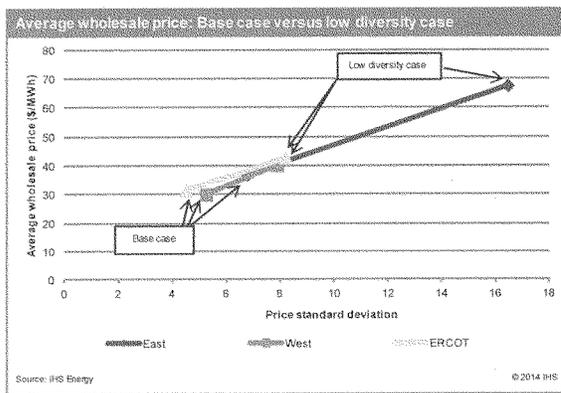
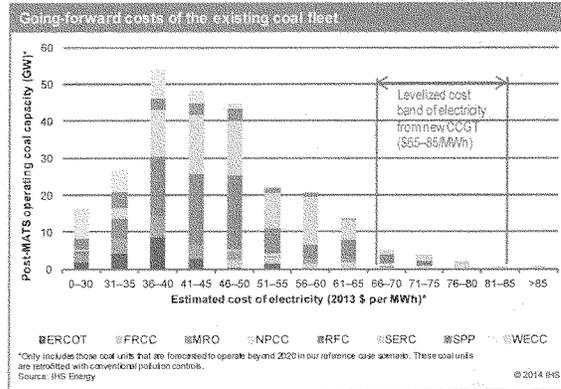


FIGURE 25



capital investment in the United States economy is 12 years. Altering the amount of capital deployed in the US economy by \$1 in Year 1 results in an equivalent impact on GDP as deploying a steady stream of about \$0.15 of capital for each of the 12 years of economic life. This annual levelized cost approximates the value of the marginal product of capital. Therefore, each dollar of capital deployed to replace a power plant that retires prematurely imposes an opportunity cost equal to the value of the marginal productivity of capital in each year.

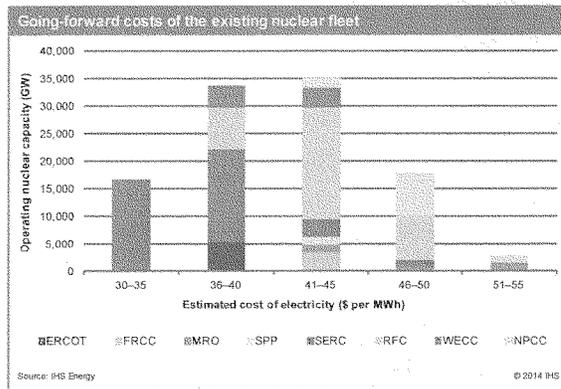
FIGURE 26



Economywide impacts

In addition to the \$93 billion in lost savings from the portfolio and substitution effects, depending upon the pace of premature closures, there is a cost to the economy of diverting capital from other productive uses. The power price increases associated with the reduced diversity case would profoundly affect the US economy. The reduced diversity case shows a 75% increase in average wholesale power prices compared to the base case. IHS Economics conducted simulations using its US Macroeconomic Model

FIGURE 27



to assess the potential impact of the change in the level and variance of power prices between the base case and the reduced diversity case. The latest IHS base line macroeconomic outlook in December 2013 provides a basis for evaluating the impacts of an electricity price shock due to a reduced diversity case for power supply. Subjecting the current US economy to such a power price increase would trigger economic disruptions, some lasting over a multiyear time frame. As a result, it would take several years for most of these disruptions to dissipate. To capture most of these effects, power price changes were evaluated over the period spanning the past two and the next three years to approximate effects of a power price change to the current state of the economy. Wholesale power price increases were modeled by increasing the

Producer Price Index for electricity by 75% in the macroeconomic model; consumers were affected by the resulting higher prices for retail electricity and other goods and services.

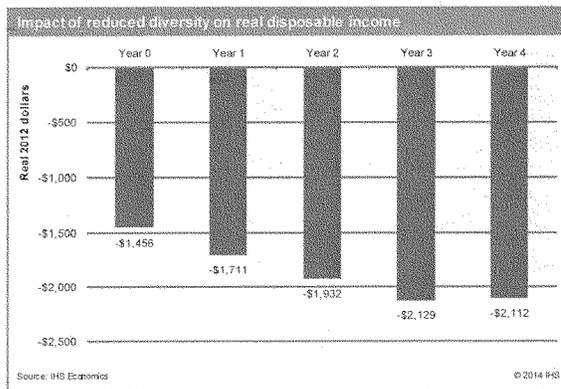
Economic impacts of the power supply reduced diversity case are quantified as deviations from the IHS macroeconomic baseline simulations of the US economy. The major impacts within the three years after the power price change would include

- A drop in real disposable income per household of about \$2,100
- A reduction of 1,100,000 jobs
- A decline in real GDP of 1.2%

Consumers will bear the brunt of the impact of higher power prices. The higher price of electricity would trigger a reduction in power use in the longer run (10 or more years out) of around 10%. Yet even with such dramatic reductions in consumption, the typical power bill in the United States would increase from around \$65 to \$72 per month.

Not only will consumers face higher electric bills, but some portion of increases in manufacturers' costs ultimately will be passed on to consumers through higher prices for goods and services. Faced with lower purchasing power, consumers will scale back on discretionary purchases because expected real disposable income per household is lower by over \$2,100 three years after the electric price increase (see Figure 28). Unlike other economic indicators (such as real GDP) that converge toward equilibrium after a few years, real disposable income per household does not recover, even if the simulations are extended out 25 years. This indicates that the price increases will have a longer-term negative effect on disposable income and power consumption levels.

FIGURE 28



Businesses will face the dual challenge of higher operational costs coupled with decreased demand for their products and services. Industrial production will decline, on average, by about 1% through Year 4. This will lead to fewer jobs (i.e., a combination of current jobs that are eliminated and future jobs that are never created) within a couple of years relative to the IHS baseline forecast, as shown in Figure 29, with the largest impact appearing in Year 2, with 1,100,000 fewer jobs than the IHS baseline level.

Impact on GDP

The US economy is a complex adaptive system that seeks to absorb shocks (e.g., increases in prices) and converge toward a long-term state of equilibrium. Although the simulations conducted for this study do not project that the US economy will fall into a recession because of power price increases, it is informative to gauge the underperformance of the US economy under the reduced diversity case. In essence, the higher power prices resulting from the reduced diversity conditions cause negative economic impacts equivalent to a mild recession relative to the forgone potential GDP of the baseline. The economic impacts of the reduced diversity case set back GDP by \$198 billion, or 1.2% in Year 1 (see Figure 30). This deviation from the baseline GDP is a drop that is equivalent to about half of the average decline in GDP in US recessions since the Great Depression. However, the impacts on key components of GDP such as personal consumption and business investment will differ.

Consumption

Analyzing personal consumption provides insights on the changes to consumer purchasing behavior under the scenario conditions. Consumption, which accounts for approximately two-thirds of US GDP, remains lower over the period with each of its three subcomponents—durable goods, nondurable goods, and services—displaying a different response to the reduced power supply scenario conditions. In contrast with overall GDP, consumer spending shows little recovery by Year 4, as shown in Figure 31. This is due to continued higher prices for goods and services and decreased household disposable income. About 57% of the decline will occur in purchases of services, where household operations including spending on electricity will have a significant impact.

FIGURE 29

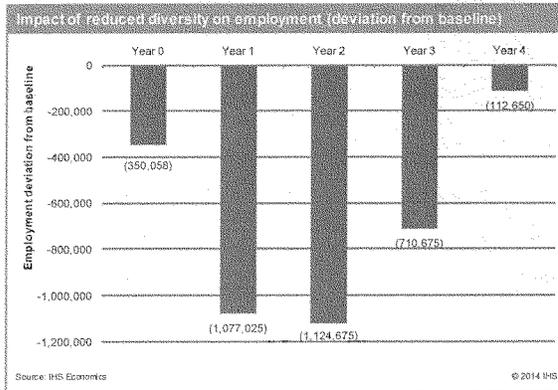
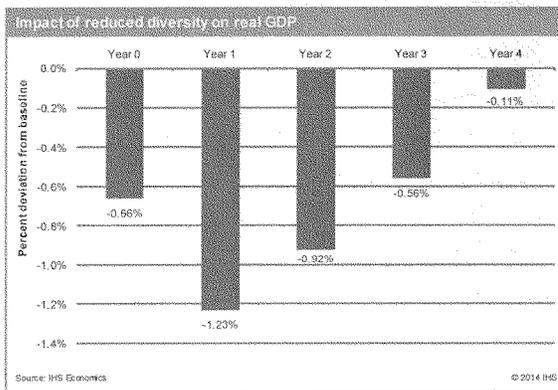


FIGURE 30



In the early years, lower spending on durable goods (appliances, furniture, consumer electronics, etc.) will account for about 33% of the decline, before moderating to 25% in the longer term. This indicates that consumers, faced with less disposable income, will simply delay purchases in the early years. The US macro simulations also predict moderate delays in housing starts and light vehicle sales, ostensibly due to consumers trying to minimize their spending.

Investment

Following an initial setback relative to the baseline, investment will recover by the end of the forecast horizon. Nonresidential investment will initially be characterized by delays in equipment and software purchases, which will moderate a few years after the electric price shock. Spending on residential structures will remain negative relative to the baseline over the four years, as shown in Figure 32. The net effect in overall investment is a recovery as the economy rebounds back to a long-run equilibrium.

In the longer term, if current trends cause the reduced diversity case to materialize

within the next decade, then the premature closure and replacement of existing power plants would shift billions of dollars of capital from alternative deployments in the US economy.

Conclusions

Consumers want a cost-effective generation mix. Obtaining one on the regulated and public power side of the industry involves employing an integrated resource planning process that properly incorporates

FIGURE 31

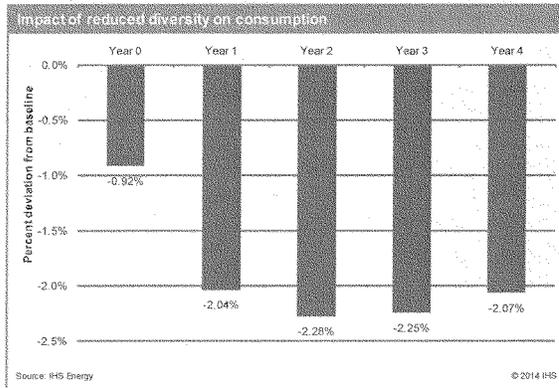
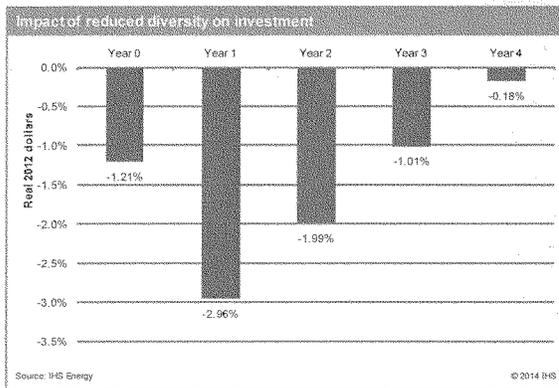


FIGURE 32



cost-effective risk management. Obtaining such a mix on the competitive side of the power business involves employing time-differentiated market-clearing prices for energy and capacity commodities that can provide efficient economic signals. The linkage between risk and cost of capital can internalize cost-effective risk management into competitive power business strategies. Regardless of industry structure, a diverse generation mix is the desired outcome of cost-effective power system planning and operation.

The results of this study indicate seven key factors that will shape US power supply diversity in the years to come:

- **Energy policy development.** US policy heavily influences the US power supply mix. Implementing an all-of-the-above energy policy requires properly internalizing the value of fuel diversity.
- **Market structure.** Market flaws distort wholesale power prices downward and result in uneconomic retirement and replacement of existing cost-effective generation resources. This issue and any market structure changes to address it will significantly shape future power plant development.
- **Energy policy discourse.** Preserving the value of fuel diversity depends on public awareness and understanding. The extent and nature of public education regarding the value of power supply diversity may strongly influence public opinion.
- **Planning alignment.** Alignment of fuel and technology choices for power generation with engineering and economic principles is critical to efficient and reliable supply. There is no single fuel or technology of choice for power generation, and all forms of power production have economic, environmental, and reliability impacts.
- **Risk assessment.** To incorporate system considerations into plant-level decisions, prudent fuel price uncertainties must be used with probabilistic approaches to decision making.
- **Flexibility.** Flexibility and exemptions in rule making and implementation allow for the balancing of costs and benefits in power supply systems and may help preserve highly valuable diversity in systemwide decisions as well as on a small but impactful individual plant scale.
- **Scope.** Including fuel price risk and additional storage and transportation infrastructure costs is crucial when evaluating reduced diversity scenarios in comparison to the cost of maintaining and expanding fuel diversity.

Appendix A: Cost-effective electric generating mix

The objective of power supply is to provide reliable, efficient, and environmentally responsible electric production to meet the aggregate power needs of consumers at various points in time. Consumers determine how much electricity they want at any point in time, and since the power grid physically connects consumers, it aggregates individual consumer demands into a power system demand pattern that varies considerably from hour to hour. For example, Figure A-1 shows the hourly aggregate demand for electricity in ERCOT.

In order to reliably meet aggregate power demands, enough generating capacity needs to be installed and available to meet demand at any point in time. The overall need for installed capacity is determined by the peak demand and a desired reserve margin. A 15% reserve margin is a typical planning target to insure reliable power supply.

The chronological hourly power demands plus the required reserve margin allow the construction of a unitized load duration curve (see Figure A-2). The unitized load duration curve orders hourly electric demands from highest to lowest and unitizes the hourly loads by expressing the values on the y-axis as a percentage of the maximum (peak) demand plus the desired reserve margin. The x-axis shows the percentage of the year that load is at or above the declining levels of aggregate demand.

This unitized load duration curve has a load factor—the ratio of average load to peak load—of 0.60. Although load duration curve shapes vary from one power system to another, this load factor and unitized load duration curve shape is a reasonable approximation of a typical pattern of electric

FIGURE A-1

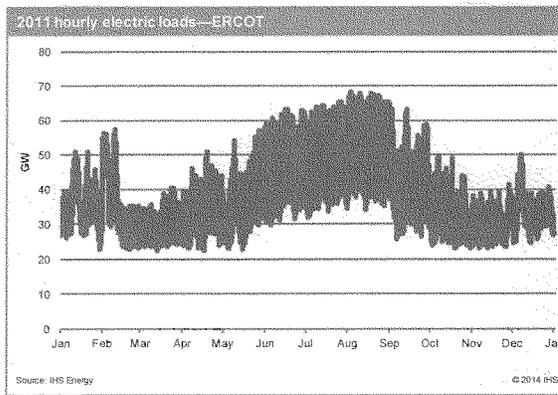
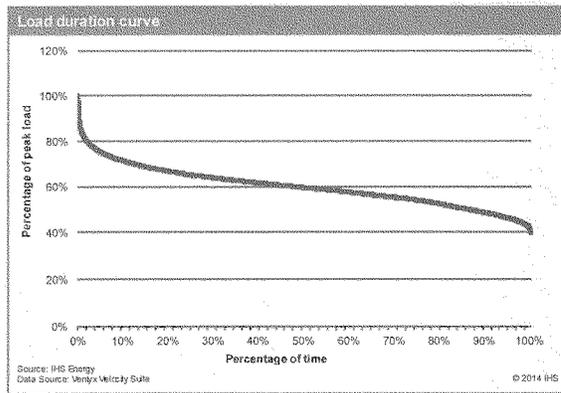


FIGURE A-2



demand in a US power system. The objective of any power system would be to match its demand pattern with cost-effective power supply.

There are a number of alternative technologies available to produce electricity. These power supply alternatives have different operating characteristics. Most importantly, some power generating technologies can produce electricity on demand that aligns with the pattern of consumer demand through time, while others cannot. For example, solar PV panels can only provide electric output during hours of sunlight and thus cannot meet aggregate demand during the night. In contrast, thermal generation such as coal and natural gas can ramp up and down or turn on and off to match output with customer demand. Technologies such as coal and natural gas are considered dispatchable, while technologies such as solar and wind are considered nondispatchable. A number of combinations of technologies can together provide electric output that matches the pattern of consumer needs.

The lowest-cost generating technologies that can meet the highest increases in demand are peaking technologies such as combustion turbines (CTs). CTs are the most economical technology to meet loads that occur for only a small amount of time. These technologies can start-up quickly and change output flexibly to meet the relatively infrequent hours of highest power demand. They are economic even though they are not the best available technology for efficiently transforming fuel into electricity. CTs have relatively low upfront capital costs and thus present a trade-off with more efficient but higher capital cost generating technology alternatives. Since these resources are expected to be used so infrequently, the additional cost of more efficient power generation is not justified by fuel savings, given their expected low utilization rates.

Cycling technologies are most economical to follow changes in power demand across most hours. Consequently, utilization rates can be high enough to generate enough fuel savings to cover the additional capital cost of these technologies over a peaking technology. These intermediate technologies provide flexible operation along with efficient conversion of fuel into power. A natural gas-fired combined-cycle gas turbine (CCGT) is one technology that is suitable and frequently used for this role.

Base-load technologies are the lowest-cost power supply sources to meet power demand across most hours. These technologies are cost-effective because they allow the trading of some flexibility in varying output for the lower operating costs associated with high utilization rates. These technologies include nuclear power plants, coal-fired power plants, and reservoir hydroelectric power supply resources.

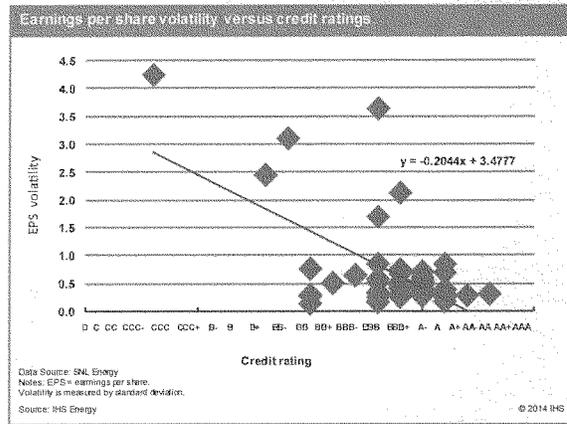
Nondispatchable power resources include technologies such as run-of-the-river hydroelectric, wind, and solar power supplies. These technologies produce power when external conditions allow—river flows, wind speeds, and solar insolation levels. Variations in electric output from these resources reflect changes in these external conditions rather than changes initiated by the generator or system operator to follow shifts in power consumer needs. Some of these resources can be economic in a generation mix if the value of the fuel they displace and their net dependable capacity are enough to cover their total cost. However, since nondispatchable production profiles do not align with changes in consumer demands, there are limits to how much of these resources can be cost-effectively incorporated into a power supply mix.

Alternative power generating technologies also have different operating costs. Typical cost profiles for alternative power technologies are shown in Table A-1. Both nuclear and supercritical pulverized coal (SCPC) technologies are based on steam turbines, whereby superheated steam spins a turbine; in coal's case, supercritical refers to the high-pressure phase of steam where heat transfer and therefore the turbine itself is most efficient. Natural gas CTs are akin to jet engines, where the burning fuel's exhaust spins the turbine. A CCGT combines both of these technologies, first spinning a CT with exhaust and then using that exhaust to create steam which spins a second turbine.

income, as shown in Figure A-4.

Sometimes the cost of capital is directly related to the power plant when project financing is used. In other cases, power companies raise capital at the corporate level with a capital cost that reflects the overall company risk profile rather than just the power plant risk profile. Utilities typically have diverse power supply portfolios, whereas merchant generators tend to be much less diverse—typically almost entirely natural gas-fired. As a result of the different supply mixes and associated risk profiles, utilities and merchant generators have different costs of capital. This difference in the cost of capital provides an approximation of the difference in risk premium.

FIGURE A-4



Overall, the cost of capital for merchant generators is higher than that for utilities broadly. While the power industry has an average cost of debt of roughly 4.5%, merchant generators with significant natural gas holdings tend to have a cost of debt of around 8%. As many of these firms have gone through bankruptcies in the past, this number may be lower than the cost of debt these firms had prior to restructuring.¹² The implied risk premium of a merchant generator to a utility is 3.5%, which is similar to the cost of capital analysis results discussed in the body of the report, where the reduced diversity case generator was calculated to have a cost of capital 310 basis points (3.1%) higher than that of the current US power sector as a whole.

Merchant generators with majority natural gas holdings have higher costs of capital because of the increased earnings volatility and risk of an all natural gas portfolio. In contrast, a generator with a more diverse portfolio needing to secure financing for the same type of plant would have costs of capital more in line with the industry as a whole. This can have a significant impact on the overall cost of the plant. This is not due specifically to the properties of natural gas as a fuel, but rather to the diversity of generating resources available. If a merchant generator were to have an exclusively coal-fired generating fleet or an exclusively nuclear generating fleet, its cost of capital would also increase owing to the higher uncertainty in generation cash flows.

The expected annual power supply costs can be calculated over the expected life of a power plant once the cost of capital is set and combined with the cost and operating profile data. These power costs are uneven through time for a given utilization rate. Therefore, an uneven cost stream can be expressed as a levelized cost by finding a constant cost in each year that has the same present value as the uneven cost stream. The discount rate used to determine this present value is based on the typical cost of capital for the power

12. Based on analysis of the "Competitive" business strategy group, defined by IHS as businesses with generation portfolios that are over 70% nonutility, based on asset value and revenue. Cost of debt based on coupon rates of outstanding debt as of May 2014.

industry as a whole. Dividing the levelized cost by the output of the power plant at a given utilization rate produces a levelized cost of energy (LCOE) for a given technology at a given utilization rate (see Figure A-5).

A levelized cost stream makes it possible to compare production costs at different expected utilization rates. A lower utilization rate forces spreading fixed costs over fewer units of output and thus produces higher levelized costs (see Figure A-6).

Figure A-7 adds the LCOE of a CT. Since the LCOE of the CT is lower than that of the CCGT at high utilization rates, adding CTs shows the point at which the savings for a CCGT's greater efficiency in fuel use are enough to offset the lower fixed costs of a CT.

There is a utilization rate at which a CCGT is cheaper to run than a CT. Below a utilization rate of roughly 35%, a CT is more economical. At higher utilization rates, the CCGT is more economical. When referring back to the load duration curve, it can be calculated that a generation mix that is 37% CT and 63% CCGT would produce a least-cost outcome. This can be demonstrated by comparing the LCOE graph with the load duration curve: the intersection point of CT and CCGT LCOEs occurs at the same time percentage on the LCOE graph at which 63% load occurs on the load duration curve (see Figure A-8).

The levelized cost of production for each technology can be determined by finding the average load (and corresponding utilization rate) for the segment of the load duration curve (LDC) that corresponds to each technology (in this example, the two segments that are created by splitting the curve at the 35% mark). Loads that occur less than 35% of the time will be considered peak loads, so the average cost of meeting

FIGURE A-5

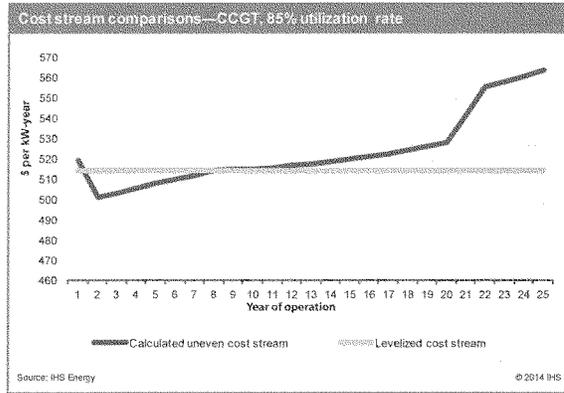
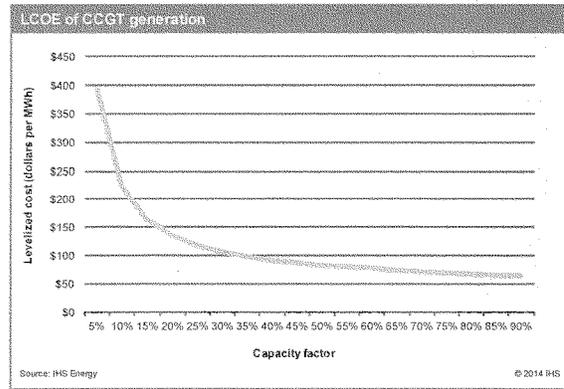


FIGURE A-6



a peak load will be equivalent to the cost of a CT operating at a 17.5% utilization rate, the average of the peak loads. Cycling loads will be defined as loads occurring between 35% to 80% of the time, with base loads occurring more than 80% of the time. As the CCGT is covering both cycling and base loads in this example, the average cost of meeting these loads with a CCGT will be equivalent to the levelized cost of a CCGT at a 57.5% utilization rate. A weighted average of the costs of each technology is then equivalent to an average cost of production for the power system. For this generation mix, the levelized cost of production is equal to 9.6 cents per kWh.

The generating options also can be expanded to include fuels besides natural gas. Stand-alone coal and stand-alone nuclear are not lower cost than stand-alone gas, as shown in Figure A-9, and all have a high-risk premium associated with the lack of diversity. However, when combined as part of a generation mix, the cost of capital will be lower owing to the more diverse (and therefore less risky) expected cash flow.

Based on the LDC, in this example base-load generation was modeled at 52.5% of capacity and was composed of equal parts gas, coal, and nuclear capacity. This combination of fuels and technology produces a diverse portfolio that can reduce risk and measurably lower the risk premium in the cost of capital.

The point at which a CCGT becomes cheaper than a CT changes slightly from the previous example owing to the change in cost of capital, but the result is similar, with a 30% utilization rate the critical point and 36% CT capacity the most economical. Cycling loads with utilization

FIGURE A-7

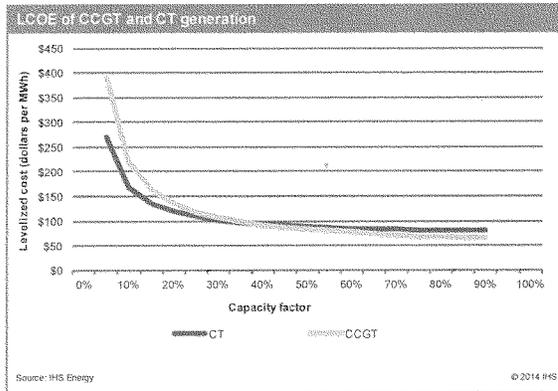
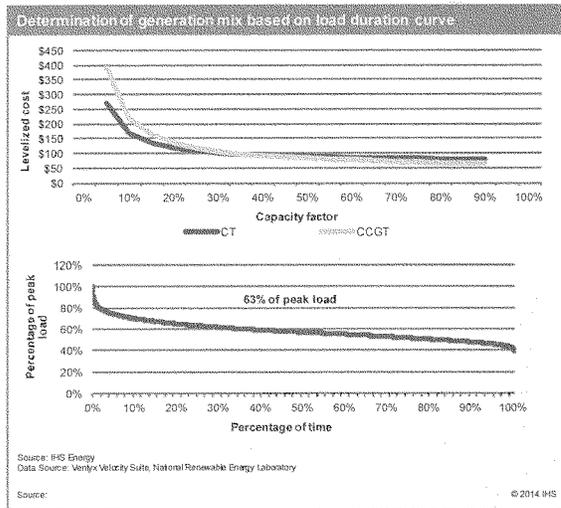


FIGURE A-8



rates between 30% and 80% can be covered by CCGTs, equaling 11.5% of capacity. The levelized cost of production for this more diverse portfolio is equal to 9.3 cents per kWh. Even though coal and nuclear have higher levelized costs than gas, all else being equal, the reduced cost of capital is more than enough to offset the increased costs of generation. The implication is that a least-cost mix to meet a pattern of demand is a diverse mix of fuels and technologies.

If the power system has a renewables mandate, this can be incorporated as well. Solar PV has a levelized cost of 14.2 cents per kWh, given a 4.5% cost of capital. If solar made up 10% of generating capacity, the load duration curve for the remaining dispatchable resources would change, as shown in Figure A-10. Using hourly solar irradiation data from a favorable location to determine solar output, the peak load of the power system does not change, as there is less than full solar insolation in the hour when demand peaks.¹³ The load factor for this new curve is 0.58, a small decrease from the original curve. A lower load factor typically means that larger loads occur less often, so more peaking capacity is necessary.

The needed dispatchable resources can be recalculated using the new curve, integrating the solar generation. The new curve increases the amount of peaking resources needed, but otherwise changes only very slightly. After solar is added, the total cost is 10.8 cents per kWh. Since the output pattern of solar doesn't match the demand pattern for the power system, adding solar does not significantly decrease the amount of capacity needed.

FIGURE A-9

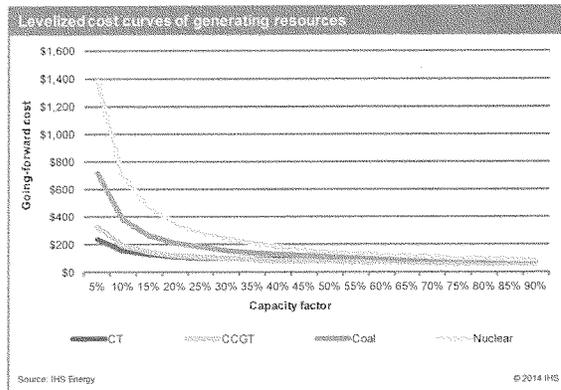
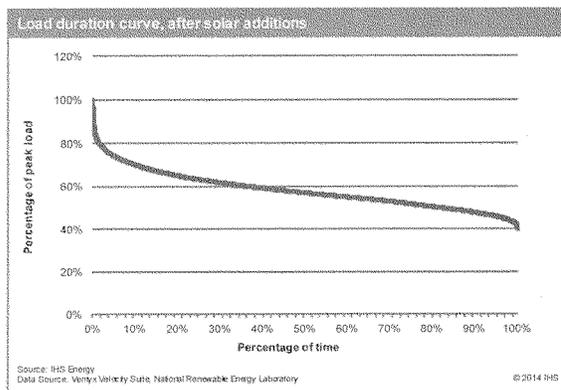


FIGURE A-10



13. Solar data from National Renewable Energy Laboratory, Austin, TX, site. Data from 1991-2005 update, used for example purposes. http://redec.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/by_state_and_city.html accessed 13 May 2014.

Conclusion

- There is no single fuel or technology of choice for power generation. Reliably and efficiently supplying consumers with the amounts of electricity that they want, when they want it, requires a diverse generation mix.
- A cost-effective generation mix involves diversity but does not involve maximizing diversity by equalizing generation shares from all available supply options.
- The cost-effective mix of fuel and technologies for any power system is sensitive to the uncertainties surrounding the level and pattern of consumer power demands as well as expectations regarding the cost and performance of alternative power generating technologies and, in particular, the expectations for delivered fuel prices.
- The cost-effective generating mix will differ from one power system to the next because of differences in aggregate consumer demand patterns as well as the cost and performance of available generating options.
- The best type of capacity to add to any generation portfolio depends on what types of capacity are already in the mix.

Appendix B: IHS Power System Razor Model overview

Design

The IHS Power System Razor (Razor) Model was developed to simulate the balancing of power system demand and supply. The model design provides flexibility to define analyses' frequency and resolution in line with available data and the analytical requirements of the research investigation.

For this assessment of the value of fuel diversity, the following analytical choices were selected:

- **Analysis time frame**—Backcasting 2010 to 2012
- **Analysis frequency**—Weekly balancing of demand and supply
- **Geographic scope**—US continental power interconnections—Western, Eastern, and ERCOT
- **Demand input data**—Estimates of weekly interconnection aggregate consumer energy demand plus losses
- **Fuel and technology types**—Five separate dispatchable supply alternatives: nuclear, coal steam, natural gas CCGT, gas CT, and oil CT
- **Supply input data by type**—Monthly installed capacity, monthly delivered fuel prices, monthly variable operations and maintenance (O&M), heat rate as a function of utilization
- **Load modifiers**—Wind, solar, hydroelectric, net interchange, peaking generation levels, and weekly patterns

Demand

The Razor Model enables the input of historical demand for backcasting analyses as well as the projection of demand for forward-looking scenarios. In both cases, the Razor Model evaluates demand in a region as a single aggregate power system load.

For backcasting analyses, the model relies upon estimates of actual demand by interconnection. For forward-looking simulations, Razor incorporates a US state-level cross-sectional, regression-based demand model for each of the three customer classes—residential, commercial, and industrial. Power system composite state indexes drive base year demand levels by customer class into the future.

Load modifiers

Utilization of some power supply resources is independent of SRMC-based dispatch dynamics. Some power supply is determined by out-of-merit-order utilization, normal production patterns, or external conditions—such as solar insolation levels, water flows, and wind patterns. These power supply resources are treated as load modifiers.

Net load

Net load is the difference between power system aggregate electric output needs and the aggregate supply from load modifiers. It is the amount of generation that must be supplied by dispatchable power supply resources.

Calibration of the inputs determining net load is possible using data reporting the aggregate output of dispatchable power sources.

Fuel- and technology-specific supply curves

Supply curves are constructed for each fuel and technology type. The supply curve for each dispatchable power supply type reflects the SRMCs of the capacity across the possible range of utilization rates. Applying availability factors to installed capacity produces estimates of net dependable (firm, derated) capacity by fuel and technology type.

Each cost curve incorporates heat rate as a function of utilization rate.¹⁴ *Heat rate* describes the efficiency of a thermal power plant in its conversion of fuel into electricity. Heat rate is measured by the amount of heat (in Btu) required each hour to produce 1 kWh of electricity, or most frequently shown as MMBtu per MWh. The higher the heat rate, the more fuel required to produce a given unit of electricity. This level of efficiency is determined primarily by the fuel type and plant design. Outliers are pruned from data to give a sample of heat rates most representative of the range of operational plants by fuel and technology type.¹⁵

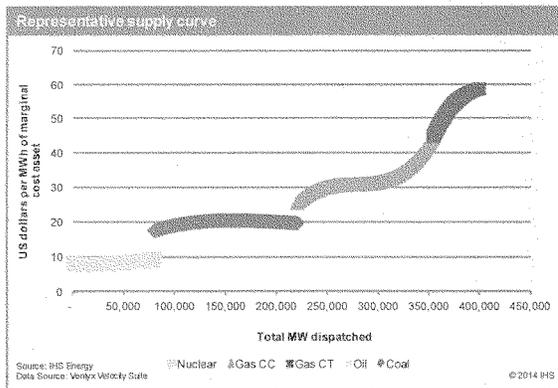
Dispatch fuel costs are the product of the heat rate and the delivered fuel cost. Total dispatch costs involve adding variable operations and maintenance (VOM, or O&M) costs to the dispatch fuel costs. These O&M costs include environmental allowance costs.

The power system aggregate supply curve is the horizontal summation of the supply curves for all fuel and technology types. Figure B-1 illustrates the construction of the aggregate power system supply curve. The supply curve shows the SRMC at each megawatt dispatch level and the associated marginal resource.

Balancing power system aggregate demand and supply

The Razor Model balances aggregate power system demand and supply by intersecting the demand and supply curves. At the intersection point, power supply equals demand; supply by type involves equilibrating the dispatch costs of available alternative sources of supply.

FIGURE B-1



14. Power plant data sourced from Ventyx Velocity Suite.

15. Outliers are defined as plants with an average heat rate higher than the maximum observed fully loaded heat rate.

This power system-wide marginal cost of production is the basis for the wholesale power price level that clears an energy market.

The Razor Model results in the following outputs:

- **Power system SRMC/wholesale price**
- **Generation by fuel and technology type**
- **Average variable cost of production.** The average variable cost is calculated at each dispatch increment by taking the total cost at that generation level divided by the total megawatt dispatch.
- **Price duration curve.** The price duration curve illustrated in Figure B-2 provides an example of wholesale power price distribution across the weeks from 2010 through 2012.

Calibration

The predictive power of the Razor Model for portfolio and substitution analysis is revealed by comparing the estimated values of the backcasting simulations to the actual outcomes in 2010-12.

The Razor Model backcasting results provide a comparison of the estimated and actual wholesale power prices. The average difference in the marginal cost varied between (3.8%) and +2.3% by interconnection region.

A comparison of the average rather than marginal cost of power production also indicated a close correspondence. The average difference between the estimate and the actual average cost of power production varied between (4.7%) and (0.1%) by interconnection region. Table B-1 shows the assessment of the predictive power of the Razor Model for these two metrics across all three interconnections in the 2010 to 2012 weekly backcasting exercise.

FIGURE B-2

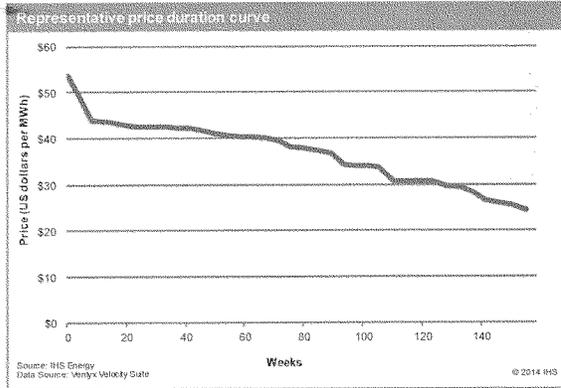


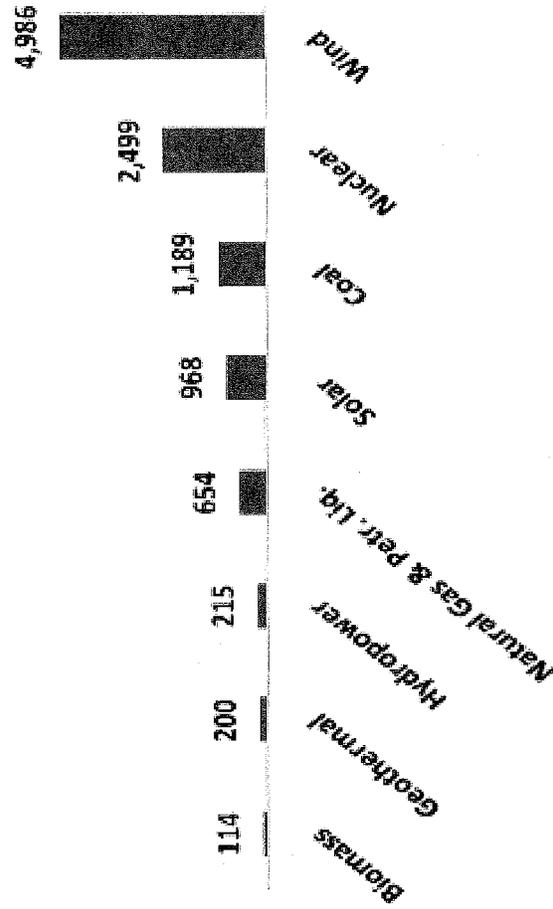
TABLE B-1

IHS power system Razor Model analysis			
	East	West	ERCOT
Average wholesale power price difference	2.3	0.3	-3.8
Average production cost difference	-0.2	-4.7	-0.1

Note: Differences reflect deviation averaged over backcasting period. Production cost difference reflects average of five power sources: Coal, gas, combined-cycle, gas combustion turbine, nuclear, and oil.
Source: IHS Energy

GRAPHS SUBMITTED BY REPRESENTATIVE LARRY BUCSHON

Federal Subsidies and Support for Electricity Production, FY 2010 (million 2010 dollars)

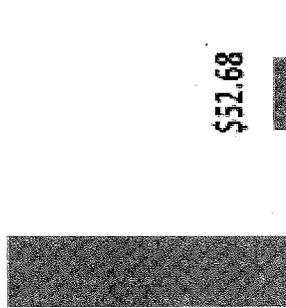


Federal Electricity Subsidies per Unit of Production

(2010 dollars per megawatthour)

(2010 dollars per megawatthour)

\$745.19



\$52.68

\$0.84

\$12.77

\$3.10

\$0.63

\$0.64

Wind

Solar

Hydropower

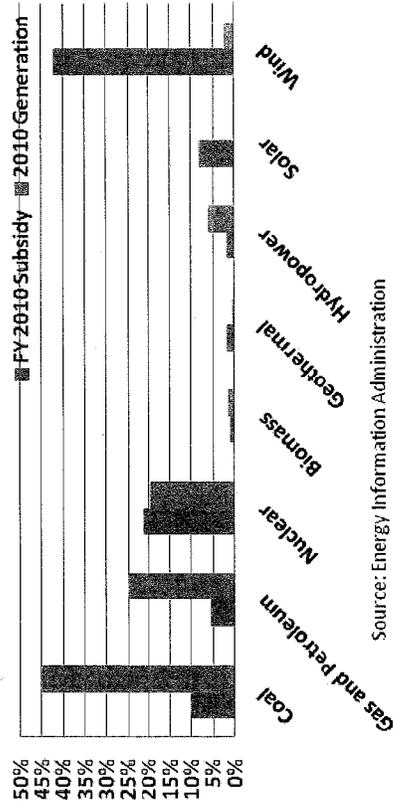
Geothermal

Nuclear

Natural Gas &
Petroleum
Liquids

Coal

Comparison of Electricity-Related Subsidy and Generation Shares by Fuel Type, FY2010



Source: Energy Information Administration

ARTICLE SUBMITTED BY REPRESENTATIVE RANDY NEUGEBAUER

Coal to the Rescue, but Maybe Not Next Winter - NYTimes.com

<http://www.nytimes.com/2014/03/11/business/energy-environment/coa...>**The New York Times** | <http://nyti.ms/11vFJW>

ENERGY & ENVIRONMENT

Coal to the Rescue, but Maybe Not Next Winter

By MATTHEW L. WALD MARCH 10, 2014

COLUMBUS, Ohio — When the temperature here dropped into the teens this winter, ice formed on the inside of Ernestine J. Cundiff's windows in the drafty 50-year-old apartment building where she lives. At 81, with diabetes, poor circulation in her legs and both shoulders damaged in separate falls last year, Ms. Cundiff said wearing leggings and fur-lined slippers was not enough to keep her warm, so she took to using an electric space heater in her bedroom.

Then came the electric bill, \$96.75 in January, up about 50 percent from the previous month. That was in addition to a gas bill of \$153.44, up from \$106.12 the month before. "When I opened the bills, I thought I was going to have another heart attack," said Ms. Cundiff, whose only income is the \$1,226 a month she receives from Social Security.

Like many other people this winter, Ms. Cundiff turned to a community service organization. Impact Community Action, a Columbus agency, enrolled her in a state program that holds energy bills to 6 percent of a person's income. Regina Clemons, the director of emergency assistance at Impact, said the group was on track to sign up 9,000 to 10,000 people this winter, compared with about 8,000 last winter.

"We find people who have never ever walked into a community action agency before, looking for help," said Carmen Allen, the community outreach coordinator.

As the end of the harshest winter in recent memory approaches, the bill is coming due for millions of consumers who are not only using more electricity and natural gas but also paying more for whatever they use. And there might

not be relief in future winters, as the coal-fired power plants that utilities have relied on to meet the surge in demand are shuttered for environmental reasons.

The sticker shock has been particularly acute in the Northeast, where natural gas supplies have been constrained. But it has spread to other regions of the country, including the Midwest, where utilities have had to draw on more expensive reserves to meet the demand.

In Pennsylvania, Attorney General Kathleen G. Kane said her office had been flooded with complaints from consumers whose utility bills had soared, in some cases tripling. In Rhode Island, the utility National Grid received permission for a 12.1 percent electricity rate increase in January, nearly all of it because of higher prices for the gas used to make electricity.

In New York, Con Edison increased the price of each kilowatt-hour about 16 percent this month compared to last year. And in Ohio, energy retailers will demand higher prices from customers like Ms. Cundiff when annual contracts are renewed.

Underlying the growing concern among consumers and regulators is a second phenomenon that could lead to even bigger price increases: Scores of old coal-fired power plants in the Midwest will close in the next year or so because of federal pollution rules intended to cut emissions of mercury, chlorine and other toxic pollutants. Still others could close because of a separate rule to prevent the damage that cooling water systems inflict on marine life.

For utilities, another frigid winter like this one could lead to a squeeze in supply, making it harder — and much more expensive — to supply power to consumers during periods of peak demand.

Senator Lisa Murkowski of Alaska, the ranking Republican on the Senate Energy Committee, told utility regulators in a speech on Feb. 11 that the recent frigid weather had provided “a glimpse of the challenge that lies ahead.” American Electric Power, which serves Columbus and a vast area of the Midwest, was running 89 percent of the coal plants that it must retire next year, she said.

“That raises a very serious question,” she said. “What happens when that

capacity is gone?”

The coal plants are dirty, and expensive compared to natural gas at summertime prices. But coal is far less prone to price jumps or to shortages, and in a cold snap, it looks like a bargain. Without the coal plants, experts agree, prices in the peak periods of winter and summer will be higher, so future periods of cold weather may be even harder on electric bills.

“We are seeing unprecedented amounts of coal units retiring,” said Andrew L. Ott, a senior vice president at PJM Interconnection, the grid operator that covers Pennsylvania, New Jersey and Maryland and has expanded into West Virginia, Ohio and adjacent areas.

“No doubt this industry is in a massive transition,” he said, adding that the change would be accompanied by more price volatility.

PJM recently set a peak record for winter energy use of about 140,000 megawatts. Its summer record is 168,000 megawatts. Plants that use coal, with a combined capacity of about 12,000 megawatts, are retiring. Enough capacity is available, and new gas-fired units are being built, but while gas production has kept up with consumption, pipeline capacity has not.

In some cases, the Environmental Protection Agency has reduced the disruption caused by retirements by delaying deadlines, to give utilities more time to comply with its rules or to get alternate arrangements in place. But American Electric Power executives say that will not be the case this time, because even with a reprieve from Washington, citizens could bring lawsuits under the Clean Air Act that would force the closures.

What’s more, many plants are far along the path to retirement. At Muskingum River, a five-boiler coal plant in Beverly, Ohio, about 100 miles southeast of Columbus, three of the units ran during the so-called polar vortex, supplying power to meet the demand.

But three-quarters of the 400 or so employees the plant had two years ago are gone, and two of the five units need half-million-dollar repairs to run again, an expensive proposition for a plant that is scheduled to close and runs only intermittently.

American Electric Power has stopped hiring at other plants that are scheduled to remain in service, to make space for employees who would like to

transfer. Units 1 and 2 at Muskingum River, commissioned in the early 1950s, cannot run anymore because they both need a new lining in the floor of their boilers, at a cost of about \$500,000 each, and there would be no time to recoup the investment. Unit 5, the youngest, commissioned in 1968, was a candidate for continued use, but it would need upgrades to reduce pollution that would cost hundreds of millions of dollars. Lately the plant has run only on very hot or very cold days.

The plants set to be closed will not be replaced by newer, cleaner coal plants, and a number of new gas plants are planned or under construction. The average price of natural gas is too low to let coal compete, and new rules loom for carbon dioxide emissions from new coal plants. And it is not only coal that is disappearing from the mix. Nuclear energy is, as well. Last year the energy company Dominion closed its Kewaunee reactor in Wisconsin, which had been running smoothly and without opposition but could not produce power at a competitive rate in the Midwest electricity market. Another energy supplier, Entergy, announced that it would close Vermont Yankee, a nuclear power station in Vernon, Vt., because the cost of production was higher than the market rate for power. In both cases, the main challenge was natural gas, which has remained cheap apart from the recent price surges.

Marvin Fertel, the president of the Nuclear Energy Institute, the industry's trade association, told Wall Street analysts on Feb. 13 that the gas crunch illustrated the need for diverse sources of energy.

"Risks are lower with diverse portfolios," he said, but the competitive market does not reward diversity. Nor does it reward a coal plant with a supply of fuel that could last weeks in a pile nearby, or a reactor with 18 to 24 months of fuel in its core, he said.

At the Muskingum River coal plant, there was resignation and uncertainty. Muskingum will be "dispositioned," in the new jargon, while other plants, with more antipollution equipment, have been designated "keepers." The plant opened six years before Craig Douglass, 54, was born, and Mr. Douglass, an outage coordinator who has worked there for 33 years, said of the people who built it, "I don't think they ever imagined they'd be running that long."

Mr. Douglass is going to a "keeper" plant. Others are retiring. In the control room one recent afternoon, there was an odd mix of crisp, modern computer screens and control panels that looked as if they had been borrowed from a 1950s science fiction film. Michael Stehly, 55, a supervisor, clearly did not want to operate either.

"I might be the guard at the gate," he said, "who lets the scrap metal trucks in and out."

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