United States Government Accountability Office

GAO

Report to the Chairman, Committee on Commerce, Science, and Transportation, U.S. Senate

July 2012

EPA REGULATIONS AND ELECTRICITY

Better Monitoring by Agencies Could Strengthen Efforts to Address Potential Challenges

GAO

Accountability * Integrity * Reliability

GAO-12-635

GAO Highlights

Accountability * Integrity * Reliability

Highlights of GAO-12-635, a report to the Chairman, Committee on Commerce, Science, and Transportation, U.S. Senate

Why GAO Did This Study

EPA recently proposed or finalized four regulations affecting coal-fueled electricity generating units, which provide almost half of the electricity in the United States: (1) the Cross-State Air Pollution Rule; (2) the Mercury and Air Toxics Standards; (3) the proposed Cooling Water Intake Structures regulation; and (4) the proposed Disposal of Coal Combustion Residuals regulation. Power companies may retrofit or retire some units in response to the regulations. EPA estimated two of the regulations would prevent thousands of premature deaths and generate $160-$405 billion in annual benefits. Some stakeholders have expressed concerns that these regulations could increase electricity prices and compromise reliability—the ability to meet consumers' demand. FERC and others have oversight over electricity prices and reliability. DOE can order a generating unit to run in certain emergencies.

GAO was asked to examine: (1) actions power companies may take in response to these regulations; (2) their potential electricity market and reliability implications; and (3) the extent to which these implications can be mitigated. GAO reviewed agency documents, selected studies, and interviewed stakeholders.

What GAO Recommends

GAO recommends, among other things, that FERC, DOE, and EPA take additional steps to monitor industry's progress in responding to the regulations. DOE and EPA agreed with this recommendation, and FERC disagreed with this and another recommendation. GAO continues to believe that it is important for FERC to take the recommended actions.

View GAO-12-635. For more information, contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov or David Trimble at (202) 512-3841 or trimbled@gao.gov.

July 2012

EPA REGULATIONS AND ELECTRICITY

Better Monitoring by Agencies Could Strengthen Efforts to Address Potential Challenges

What GAO Found

It is uncertain how power companies may respond to four key Environmental Protection Agency (EPA) regulations, but available information suggests companies may retrofit most coal-fueled generating units with controls to reduce pollution, and that 2 to 12 percent of coal-fueled capacity may be retired. Some regions may see more significant levels of retirements. For example, one study examined 11 states in the Midwest and projected that 18 percent of coal-fueled capacity in that region could retire. EPA and some stakeholders GAO interviewed stated that some such retirements could occur as a result of other factors such as lower natural gas prices, regardless of the regulations. Power companies may also build new generating units, upgrade transmission systems to maintain reliability, and increasingly use natural gas to produce electricity as coal units retire and remaining coal units become somewhat more expensive to operate.

Available information suggests these actions would likely increase electricity prices in some regions. Furthermore, while these actions may not cause widespread reliability concerns, they may contribute to reliability challenges in some regions. Regarding prices, the studies GAO reviewed estimated that increases could vary across the country, with one study projecting a range of increases from 0.1 percent in the Northwest to an increase of 13.5 percent in parts of the South more dependent on electricity generated from coal. According to EPA officials, the agency's estimates of price increases would be within the historical range of price fluctuations, and projected future prices may be below historic prices. Regarding reliability, these actions are not expected to pose widespread concerns but may contribute to challenges in some regions. EPA and some stakeholders GAO interviewed indicated that these actions should not affect reliability given existing tools. Some other stakeholders GAO interviewed identified potential reliability challenges. Among other things, it may be difficult to schedule and complete all retrofits to install controls and to resolve all potential reliability concerns associated with retirements within compliance deadlines.

Existing tools could help mitigate many, though not all, of the potential adverse implications associated with the four EPA regulations, but the Federal Energy Regulatory Commission (FERC), Department of Energy (DOE), and EPA do not have a joint, formal process to monitor industry's progress in responding to the regulations. Some tools, such as state regulatory reviews to evaluate the prudence of power company investments, may address some potential price increases. Furthermore, tools available to industry and regulators, as well as certain regulatory provisions, may address many potential reliability challenges. However, because of certain limitations, these tools may not fully address all challenges where generating units needed for reliability are not in compliance by the deadlines. FERC, DOE, and EPA have responsibilities concerning the electricity industry, and they have taken important first steps to understand these potential challenges by, for example, informally coordinating with power companies and others about industry's actions to respond to the regulations. However, they have not established a formal, documented process for jointly and routinely monitoring industry's progress and, absent such a process, the complexity and extent of potential reliability challenges may not be clear to these agencies. This may make it more difficult to assess whether existing tools are adequate or whether additional tools are needed.

Contents

Tables

Figures

Abbreviations

ACI	activated carbon injection unit
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals Regulation
CSAPR	Cross-State Air Pollution Rule
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ESP	electrostatic precipitator
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
MATS	Mercury and Air Toxics Standards
MISO	Midwest Independent Transmission System Operator, Inc.
MW	megawatt
NERC	North American Electric Reliability Corporation
NO_x	nitrogen oxides
PJM	PJM Interconnection
RFF	Resources for the Future
RTO	Regional Transmission Organization
SCR	selective catalytic reduction unit
SNCR	selective non-catalytic reduction unit
SO_2	sulfur dioxide

G A O
Accountability * Integrity * Reliability
United States Government Accountability Office
Washington, DC 20548

July 17, 2012

The Honorable John D. Rockefeller IV
Chairman
Committee on Commerce, Science,
and Transportation
United States Senate

Dear Mr. Chairman:

Coal is an abundant and widely used fuel source in the United States, producing about 42 percent of the nation's electricity supply in 2011. Coal-fueled power plants have historically been among the least costly sources of electricity in the country. However, burning coal and other fossil fuels (i.e., natural gas and oil) to produce electricity is associated with human health and environmental concerns. For example, fossil fuel electricity generating units are among the largest emitters of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), which have been linked to respiratory illnesses and acid rain and which may travel great distances and affect air quality in states downwind from generating units—downwind states.[1] In 2008, the last year for which EPA has such comprehensive information, coal-fueled units emitted about 48 percent of the nation's mercury, a hazardous air pollutant and heavy metal linked to neurological disorders in children and harm to wildlife. In addition, coal-fueled generating units emit large quantities of carbon dioxide, the primary greenhouse gas contributing to climate change, and can use significant quantities of water and create large amounts of waste products that require disposal.

To address concerns over air pollution, water resources, and solid waste, several environmental laws, including the Clean Air Act, Clean Water Act, and Resource Conservation and Recovery Act, were enacted. As required or authorized by these laws, the Environmental Protection Agency (EPA), the primary federal agency responsible for implementing many of the nation's environmental laws, recently proposed or finalized

[1]An electricity generating unit consists of any combination of an electricity generator, reactor, boiler, combustion turbine, or other equipment operated together to produce electrical power. A power plant is a facility with one or more generating units, together with other equipment used to produce electric power.

four key regulations that will affect coal-fueled units.[2] These four regulations are: (1) the Cross-State Air Pollution Rule (CSAPR), which prohibits certain emissions of air pollutants in 28 states because of the impact they would have on air quality in other states; (2) the National Emissions Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units, also known as the Mercury and Air Toxics Standards (MATS), which establishes emissions limitations on mercury and other toxic pollutants; (3) the proposed Cooling Water Intake Structures at Existing Facilities and Phase I Facilities regulation, which we refer to as 316(b), which would establish requirements for water withdrawn and used for cooling purposes that reflect the best technology available to minimize adverse environmental impact; and (4) the proposed Disposal of Coal Combustion Residuals from Electric Utilities regulation (CCR), which would govern the disposal of coal combustion residuals, such as coal ash, in landfills or surface impoundments.

These four regulations have potentially significant implications for public health and the environment. In particular, EPA projects that, among other benefits, CSAPR would reduce SO_2 emissions by 73 percent and NO_x emissions by over half in covered states, reducing asthma and related human health impacts. In addition, EPA projects that MATS would reduce mercury emissions by 75 percent from coal-fueled electricity generating units, reducing the impacts of mercury on adults and children. In 2016, EPA estimates that the final versions of MATS and CSAPR could generate $160 billion to $405 billion in monetized annual benefits (in 2011 year dollars), preventing tens of thousands of premature deaths and reducing pollution-related illnesses.[3]

These four regulations could also have significant implications for the electricity industry. Generating units fueled by coal—which comprise a

[2]On April 13, 2012, EPA proposed new source performance standards for greenhouse gas emissions from certain new fossil fuel electricity generating units, but the standards would not apply to existing units. We do not discuss this proposed regulation in this report.

[3]Unless otherwise noted, all dollar estimates presented in this report have been converted to 2011 year dollars using the gross domestic product deflator based on the calendar year. EPA's estimates of the benefits of the regulations presented here refer to monetized benefits. As not all benefits can be monetized, these may represent a subset of overall benefits of the regulations. We did not independently assess EPA's estimates of the benefits of these regulations.

large portion of the national electricity supply—are expected to be affected by the four proposed regulations. Power companies might retrofit some generating units with controls to reduce pollutants[4] and, when it is not economic to retrofit, may retire some generating units, according to EPA.[5] Several representatives from power companies and officials from federal and state regulatory agencies have expressed concerns that, as companies incur additional costs in responding to these regulations, and as the electricity supply is affected by generating unit retirements, electricity prices could increase and reliability—the ability to meet consumers' electricity demand—could be compromised.[6]

Federal agencies and other stakeholders have some responsibilities for overseeing actions power companies take in response to the regulations and have a role in mitigating some potential adverse implications. The Federal Energy Regulatory Commission (FERC) is generally responsible for ensuring that certain electricity and transmission prices are "just and reasonable," as well as approving and enforcing standards for reliability in the bulk power system—the interconnected transmission system combined with the electric power from generating units needed to maintain the system. The Department of Energy (DOE) works to modernize the electricity system, enhance the security and reliability of the nation's energy infrastructure, and facilitate recovery from any disruptions. DOE also has authority to compel generating units to produce electricity in certain emergency situations. Other stakeholders also play key roles, such as state environmental and electricity regulators and system planners that coordinate planning decisions regarding transmission and generation infrastructure to maintain the reliable supply

[4]Compliance with the four key regulations may involve using various technologies. It may also include making infrastructure changes to reduce environmental impacts; for example, installing liners at facilities used to store coal combustion residuals to minimize leaching of contaminants into groundwater. We refer to all of these as controls.

[5]Multiple types of power companies exist in the electricity industry, including owners of electricity generating units and owners of transmission systems, as well as integrated companies that own both generation and transmission. In addition, some companies sell electricity directly to customers; these companies may or may not own any generating units or transmission systems. We generally use the term power company to refer to those companies that own generation and may or may not also own transmission.

[6]We use the term "responding to the regulations" to refer to such actions as installing controls, retiring units, and other actions such as building new generating capacity to replace that lost in retirements.

of electricity to consumers.[7] In a December 2011 memorandum, the President directed EPA to, among other things, promote early, coordinated, and orderly planning and execution of the measures needed to implement MATS while maintaining electricity reliability, including coordination with DOE, FERC and others.

In this context, you asked us to provide information on the implications of the four key recently proposed or finalized EPA regulations. Our objectives were to examine: (1) what available information indicates about actions power companies may take at coal-fueled generating units in response to the four key EPA regulations; (2) what available information indicates about these regulations' potential implications on the electricity market and reliability; and (3) the extent to which EPA, FERC, DOE, and other stakeholders can mitigate adverse electricity market and reliability implications, if any, associated with requirements in these regulations.

To examine what available information indicates about actions power companies may take in response to these regulations and their potential market and reliability implications, we (1) selected for review 12 studies of companies' projected responses to the regulations and the potential impacts of these responses and (2) analyzed data from Ventyx Velocity Suite on electricity generating units. We considered several factors in selecting studies, including how closely they reflect the four regulations, and we assessed the reasonableness of the studies' assumptions and methodologies. The studies we selected were carried out by EPA, the Energy Information Administration (EIA), system planners, research organizations, and a consulting firm.[8] In some cases, we identified differences between study assumptions and the regulations, which we note in the text where appropriate. The actual pricing and reliability implications of these regulations will depend on various uncertain factors, such as future market conditions and the ultimate regulatory requirements, but we determined that these studies were reasonable for describing what is known about the range of potential implications of the

[7]In this report, we use the term "system planner" to refer to those entities with responsibility for advance planning to ensure there are adequate transmission and generation resources to meet demand while operating the grid reliably. This usage does not directly align with planning terminology used by the North American Electric Reliability Corporation (NERC).

[8]EIA is a statistical agency within DOE that collects, analyzes, and disseminates independent information on energy issues.

four regulations. We used data from Ventyx Velocity Suite, as of April 9, 2012, to describe coal-fueled generating units and to provide information on historic and planned retrofits and retirements of such units. Ventyx Velocity Suite is a proprietary database containing consolidated energy data from EIA, EPA, and other sources. Information regarding planned retrofits and retirements reflect publicly reported plans as identified by Ventyx. As plans may change, actual future retrofits and retirements may differ from the data in these plans. To examine the extent to which agencies and other stakeholders can mitigate any adverse implications, we interviewed officials at the EPA, FERC, and DOE, and reviewed relevant documents. To address all three objectives, we summarized the results of semistructured interviews with a nonprobability sample of 33 stakeholders, including officials from EPA, FERC, and DOE; representatives of power companies; regional transmission system operators; state regulators; and researchers. We selected these stakeholders to be broadly representative of differing perspectives on these issues based on recommendations from EPA, FERC, DOE, industry associations and such factors as the percentage of companies' generating capacity that is coal-fueled. We provided a preliminary list of the stakeholders we intended to interview to FERC and EPA, and we incorporated their suggestions in considering stakeholders where appropriate. Because we used a nonprobability sample, the views of these stakeholders are not generalizable to all potential stakeholders but they provide illustrative examples. Appendix I provides additional information on our scope and methodology, appendix II lists the stakeholders we interviewed, and appendix III lists the studies we reviewed.

We conducted this performance audit from July 2011 to July 2012 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

This section describes the role of coal in generating electricity, the four key EPA regulations, actions involved in maintaining electric reliability, and federal and state government roles in electricity markets.

Role of Coal in Electricity Generation

Because of the abundance of coal and its historically low cost, many coal-fueled electricity generating units were built and these provide a large share of the electricity produced in the United States. In 2010, there were 1,396 coal-fueled generating units in the United States,[9] with a total 316,800 megawatts (MW) of net summer generating capacity—about 30 percent of the total generating capacity in the United States.[10] In addition to coal, electricity is produced by burning other fossil fuels, particularly natural gas and oil; using nuclear power through nuclear fission; and using renewable sources, including hydropower, wind, geothermal, and solar.

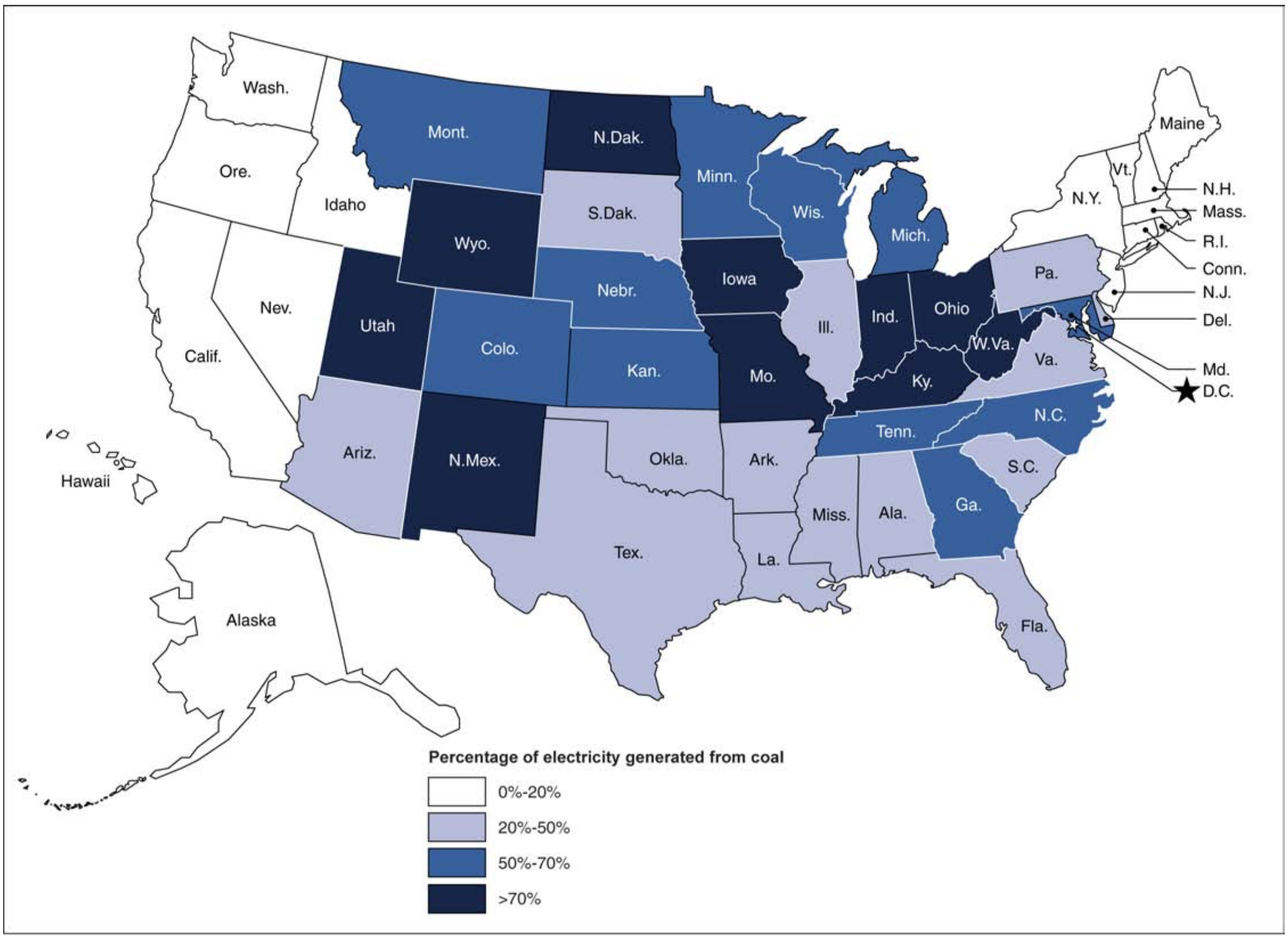
Coal is the largest source of electricity generation, but the percentage of electricity produced using coal has declined—from 53 percent in 1990 to about 42 percent in 2011—and coal's role in the electricity system is changing due to a number of factors. According to some stakeholders we interviewed, several broad trends are affecting the use of coal and contribute to the retirement of coal-fueled generating units. First, in some areas of the country, it has become less economically attractive to use coal to produce electricity, as the regional prices of coal have increased, and prices for natural gas have fallen and the availability of natural gas has increased. Second, demand for electricity is projected to grow slowly in some areas, limiting the need for new power plants. Third, a portion of coal-fueled generating units are old—73 percent of coal-fueled capacity was 30 years or older at the end of 2010—and less efficient than other sources. Despite these trends, coal is expected to continue to be a major fuel source in the future, with the EIA recently projecting coal to account for about 39 percent of the United States' electricity by 2035 with current policies. We are examining these issues and expect to report later this year on how the use of coal in electricity production is expected to change.

[9]Not all of these coal-fueled units would be subject to each of the four regulations. Additionally, noncoal electric generating units are subject to some of the regulations. Each regulation defines which units will be subject to it. For example, MATS applies to coal- and oil-fueled electricity utility steam generating units that have over 25 MW capacity and meet other requirements. We use the term electricity generating units rather than the specific regulatory definitions to refer to units subject to one or more regulation.

[10]Generating capacity is measured in MW and refers to the maximum capability of a unit to produce electricity. A unit with 1,000 MW of capacity can generate up to 1,000 megawatt-hours of electricity in 1 hour, enough to provide electricity for up to 1 million homes.

Reliance on coal varies significantly around the country. As shown in figure 1, in 2010, coal was used to generate the majority of electricity produced in several states, particularly in the Midwest, while little of the electricity generated in states on the West Coast and in New England was from coal.

Figure 1: Percentage of Electricity Generated from Coal by State, 2010



Sources: GAO analysis of EIA data; Map Resources (map).

The Four Key EPA Regulations

Four recent key EPA regulations address air pollution from electricity generating units, disposal of coal combustion residuals from certain generating units, and death of aquatic life as a result of water withdrawal for use for cooling at certain electricity generating units. As outlined in table 1, these regulations are at different stages of development, have different compliance deadlines, and EPA estimates that they will generate significant monetized benefits and costs.

Table 1: Major Milestones, Benefits and Costs of Four Key EPA Regulations

Regulation	Date proposed	Date finalized	Compliance deadline	EPA estimate of annualized benefits and costs (in billions 2011 dollars)[a]
CSAPR	August 2010	August 2011[b]	First phase was to begin in 2012 but is uncertain because of a court stay.	$128-$299 in benefits and $0.9 in costs[c]
MATS	May 2011	February 2012[d]	April 2015 1-year extension (to April 2016) through permitting authorities possible 1 additional year possible through Clean Air Act Administrative Order (to April 2017)	$39-$96 in benefits and $10.2 in costs[c]
CCR	June 2010	No schedule for finalization	Depends on which option is finalized	$0.09-$1.3 in benefits and $0.6-$1.5 in costs, depending on which option is finalized[e]
316(b)	April 2011	Scheduled July 2012	As proposed, would be established on a case-by-case basis by permitting authorities up to 8 years for impingement controls and entrainment controls anticipated to take longer	$0.02 in benefits and $0.4 in costs

Source: GAO analysis of EPA information.

Note: The proposed and finalized dates are the regulations' publication dates in the Federal Register, not the dates EPA signed the regulations and publicly released them. With the exception of CCR, the costs and benefits reflect actions taken by both coal-fueled units and other sources affected by the regulations. CCR would only apply to coal combustion residuals generated by coal-fueled units.

[a]Cost and benefit estimates were converted to 2011 dollars using the gross domestic product deflator based on the calendar year. All estimates reflect a 3 percent discount rate except for CCR, where EPA used a 7 percent discount rate. EPA officials told us that it would be inappropriate to add together these estimates because of differences in baselines and analysis years. EPA did not provide an estimate of the overall impact of the four regulations.

[b]The regulation and its federal implementation plans have subsequently been amended. On December 30, 2011, a federal court stayed the regulation while it hears the case challenging the regulation finalized in August 2011. A lawsuit challenging one of the amendments has also been filed, but the court put it on hold while it considers the case challenging the August 2011 rulemaking.

[c]EPA estimates of the costs and benefits of MATS and CSAPR refer to annualized costs and benefits in 2014 for CSAPR and 2016 for MATS.

[d]Several lawsuits have been filed challenging MATS, but the court has not issued any decisions.

[e]Reflects EPA's estimate of costs and benefits assuming no change in the beneficial use of combustion residuals.

Air Pollution: CSAPR and MATS

Coal-fueled electricity generating units are a major source of air pollution in the United States. Burning coal for electricity production results in the emission of pollutants such as SO_2, NO_x, mercury and other metals, and acid gases. Coal-fueled electricity generating units are among the largest emitters of these pollutants. This air pollution has adverse health and environmental effects. For example, SO_2 and NO_x emissions contribute to the formation of fine particulate matter, and NO_x contributes to the formation of ozone. Fine particulate matter may aggravate respiratory and cardiovascular diseases and is associated with asthma attacks and premature death. Ozone can inflame lung tissue and increase susceptibility to bronchitis and pneumonia. In addition to affecting health, SO_2 and NO_x reduce visibility and contribute to acid rain, which can acidify streams and change the nutrient balance in coastal waters and large river basins, affecting their ability to support fish and other wildlife. Mercury is a toxic element, and human intake of mercury, for example, through consumption of fish that ingested the mercury, has been linked to a wide range of health ailments. In particular, mercury can harm fetuses and cause neurological disorders in children, resulting in, among other things, impaired cognitive abilities. Other toxic metals emitted from power plants, such as arsenic, chromium, and nickel can cause cancer. Acid gases cause lung damage and contribute to asthma, bronchitis, and other chronic respiratory diseases, especially in children and the elderly.

The Clean Air Act requires EPA to establish national ambient air quality standards that states are primarily responsible for attaining.[11] States generally develop state implementation plans that detail how the standards will be attained and maintained. In addition, the act's Good Neighbor provision requires state implementation plans to prohibit emissions of air pollutants in amounts that will contribute significantly to nonattainment or interference with maintenance of a national ambient air quality standard in any other state. Electricity generating units contribute to pollution that affects the ability of downwind states to attain and maintain these standards because some of these pollutants may travel in the atmosphere hundreds or thousands of miles from the areas where they originate. If a state fails to develop and submit a state implementation plan that satisfies all Clean Air Act requirements, including the Good Neighbor provision, by specified deadlines, EPA is

[11]EPA has set national ambient air quality standards for carbon monoxide, lead, NO_x, ozone, particulate matter, and sulfur oxides.

required to issue a federal implementation plan.[12] EPA issued regulations interpreting and clarifying the Good Neighbor provisions in 1998 and 2005, but a federal court found the 2005 regulation and its federal implementation plans to be unlawful. Although the court remanded the 2005 regulation to EPA in 2008, it allowed the regulation and its federal implementation plans to remain in effect until EPA issued a replacement regulation.[13]

In 2011, EPA finalized CSAPR and its federal implementation plans to replace the 2005 regulation and its federal implementation plans. Subsequently, EPA finalized amendments to the regulation and federal implementation plans and issued federal implementation plans for additional states. As amended, CSAPR would require emissions reductions in 28 states spanning much of the eastern half of the United States to address each state's significant contribution to nonattainment and interference with maintenance of the air quality standards in downwind states.[14] (See fig. 2 for states that would be covered by CSAPR.) The reductions are to be achieved through the federal implementation plans that regulate certain electricity generating units by establishing SO_2 and NO_x trading programs. Under each trading program, covered states have SO_2 and NO_x emissions budgets and receive emissions allowances equal to the budget, which are distributed to power companies with generating units in that state. Each emissions allowance represents the right to emit 1 ton of SO_2 or NO_x. The allowances may be bought, sold, or banked for use in later years, but power companies must own enough allowances at the end of each control period to cover their emissions. Power companies with insufficient allowances at the end of

[12]States can replace federal implementation plans by developing and submitting for EPA approval state implementation plans that achieve the required amount of emissions reductions.

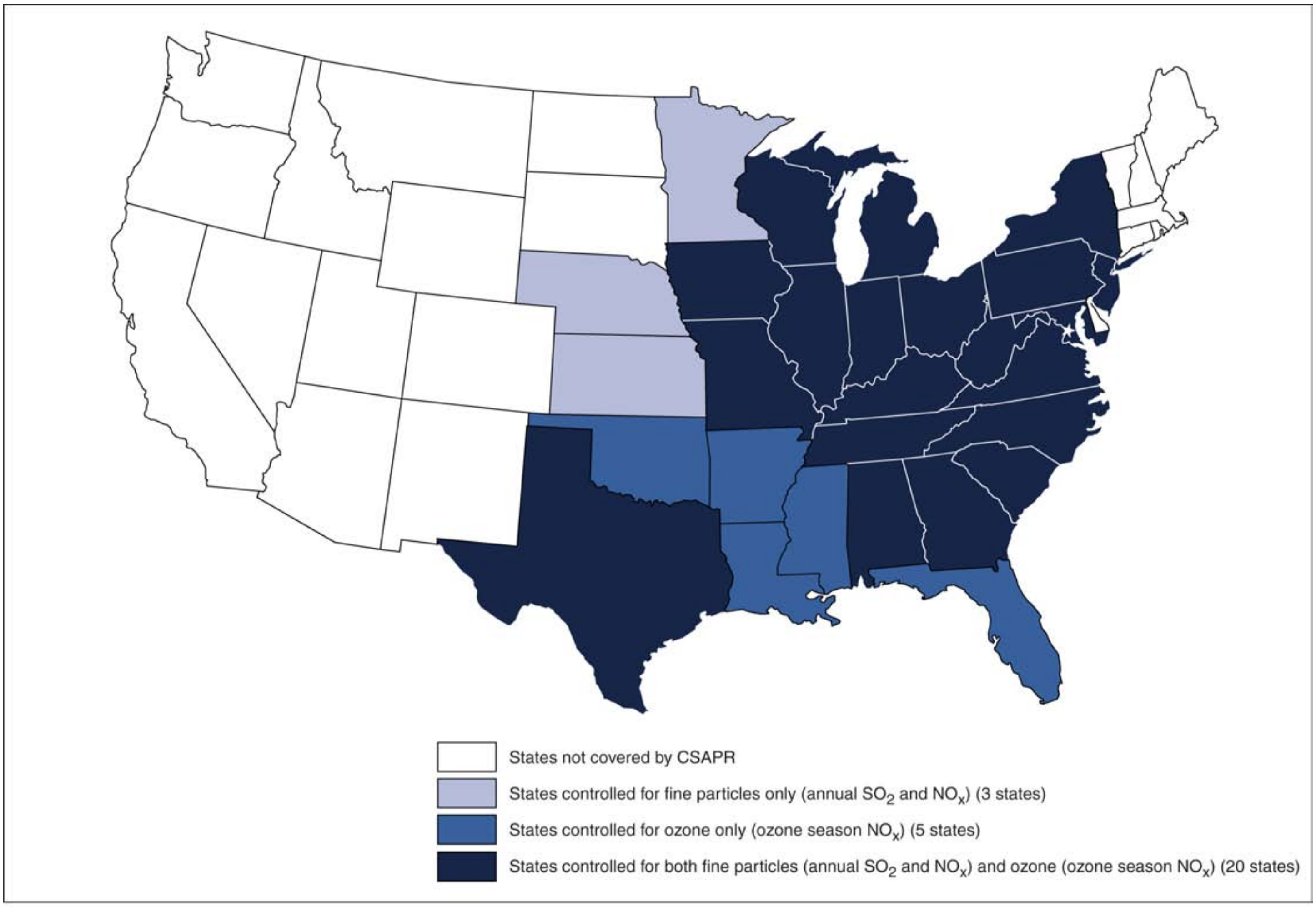
[13]The 2005 regulation—known as the Clean Air Interstate Rule (CAIR)—requires 27 states and the District of Columbia to adopt and submit revisions to their state implementation plans to eliminate SO_2 and NO_x emissions that contribute significantly to downwind nonattainment of certain national ambient air quality standards. The CAIR federal implementation plans issued in 2006 regulate electricity generating units in the covered states and achieve CAIR's emissions reductions requirements. The court allowed CAIR and its federal implementation plans to remain in effect until replaced because, even with flaws, they would at least temporarily preserve the environmental values covered by CAIR.

[14]CSAPR would cover certain fossil fuel electricity generating units with over 25 MW capacity.

the control period could be subject to financial penalties and must surrender two allowances for each excess ton of pollution emitted. EPA projects that CSAPR would reduce SO_2 emissions by 73 percent and NO_x emissions by 54 percent in the covered states and could avoid 13,000 to 34,000 premature deaths, generating $128 to $299 billion in benefits, with $853 million in costs in 2014. The control periods for some of the trading programs were scheduled to begin on January 1, 2012, but the U.S. Court of Appeals for the D.C. Circuit stayed CSAPR on December 30, 2011.[15] Depending on how the court rules, CSAPR may change.

[15] A lawsuit challenging one of the amendments to CSPAR has also been filed, but the court put it on hold while it considers the case challenging the CSPAR regulation finalized in August 2011.

Figure 2: States Covered by CSAPR



Sources: EPA; Map Resources (map).

The Clean Air Act also requires EPA to study the public health hazards from electricity generating units' emissions of mercury and other hazardous air pollutants and to regulate those emissions under section 112 if it finds that such regulation is "appropriate and necessary." EPA made such a finding regarding certain electricity generating units in 2000 but did not issue a regulation under section 112.[16] In 2005, EPA reversed this finding and finalized a regulation under section 111 of the Clean Air Act regulating mercury emissions from certain electricity generating units, which a federal court later struck down. Pursuant to a settlement agreement to resolve a lawsuit for failing to meet the statutory deadline for issuing a section 112 regulation, EPA published the final MATS regulations in February 2012.[17] Among other things, MATS establishes numerical emissions limitations for mercury, filterable particulate matter (as a surrogate for all toxic nonmercury metal pollutants), and hydrogen chloride (as a surrogate for all toxic acid gas pollutants) at certain new and existing generating units. All of the numerical limitations applicable to existing units except one are set at the average emissions limitation achieved by the best performing 12 percent of existing sources.[18] Generating units would have 3 years, until April 2015, to comply with MATS and could receive up to a 1-year extension from permitting authorities (typically state or local authorities), if necessary for the installation of controls. EPA also outlined a mechanism to allow units that are needed to address specific and documented reliability concerns to receive Clean Air Act administrative orders to provide up to an additional

[16]Specifically, the finding was regarding coal- and oil-fueled electric utility steam generating units. EPA also found that regulation of hazardous air pollutants emissions from natural gas-fueled electric utility steam generating units was not appropriate or necessary.

[17]The statutory deadline for issuing section 112 regulations for hazardous air pollutants from coal- and oil-fueled electric utility steam generating units was 2 years from the date on which the units were listed as sources of hazardous air pollutants subject to regulation, which was December 20, 2000. In 2008, EPA settled a lawsuit alleging that it had failed to promulgate emissions standards under section 112 for hazardous air pollutants from coal- and oil-fueled electric utility steam generating units by agreeing to sign a final regulation by the end of 2011.

[18]Specifically, MATS applies to electricity utility steam generating units that have over 25 MW capacity and meet other requirements. MATS also establishes work practice standards in lieu of numerical emissions limitations for organic hazardous air pollutants and for limited use oil-fueled electric utility steam generating units as defined in the final regulation.

year to come into compliance.[19] EPA estimates that the final standards would reduce mercury emissions from coal-fueled electricity generating units by 75 percent and reduce hydrogen chloride emissions by 88 percent. EPA estimated the benefits of MATS would be $39 to $96 billion with costs of $10.2 billion in 2016. Petitions for review of MATS have been filed in the U.S. Court of Appeals for the D.C. Circuit, but the court has not yet issued a ruling. Depending on how the court rules, MATS may change.

Disposal of Coal Combustion Residuals: CCR

Burning coal to produce electricity creates combustion residuals, such as coal ash, which represent one of the largest waste streams in the United States. These residuals contain contaminants like mercury, cadmium, and arsenic that are associated with cancer and various other serious health effects. Coal combustion residuals can be disposed of wet (mixed with water) in large surface impoundments, or dry in landfills.[20] EPA has stated that many landfills and impoundments lack liners and groundwater monitoring systems, and without proper protections, contaminants can leach into groundwater and migrate to drinking water sources, posing significant public health concerns.[21]

The Resource Conservation and Recovery Act authorizes EPA to establish regulations for the treatment, storage, and disposal of hazardous waste and to establish national minimum criteria for the

[19]EPA's Office of Enforcement and Compliance Assurance issued a policy memorandum describing its intended approach regarding the use of Clean Air Act Section 113(a) administrative orders for sources that must operate in noncompliance with MATS for up to a year to address a specific and documented reliability concern. See: EPA, "The Environmental Protection Agency's Enforcement Response Policy For Use of Clean Air Act Section 113(a) Administrative Orders in Relation To Electric Reliability and the Mercury and Air Toxics Standard" (available at http://www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf).

[20]Some coal combustion residuals have beneficial uses; for example, they can be used in the manufacture of such construction materials as concrete or wallboard. According to EPA documentation, about 37 percent of coal combustion residuals are used beneficially. EPA did not propose to regulate the beneficial use of coal combustion residuals, though some industry officials have expressed concerns that designating residuals as hazardous could negatively impact beneficial uses.

[21]Furthermore, accidents—such as the 2008 breach of a dike at a Tennessee Valley Authority coal plant impoundment—can result in large-scale releases of coal combustion residuals. The 2008 accident caused the release of 5.4 million cubic yards of coal ash into a nearby river and covered more than 300 acres with coal ash; it also damaged homes, roads, rail lines, and utilities.

disposal of nonhazardous solid waste to protect human health and the environment. In June 2010, to address risks from the disposal of coal combustion residuals generated at electricity generating units, EPA proposed CCR to regulate coal combustion residuals for the first time.[22] EPA co-proposed two alternative regulations. Under the first, EPA would list residuals as a special waste and regulate them as a hazardous waste by establishing requirements for their management from generation to disposal. Under the second option, EPA would regulate coal combustion residuals as nonhazardous solid waste and establish national minimum standards for their disposal in surface impoundments or landfills. Regulation as a special waste would occur through a federal or authorized state permitting program with requirements for its storage, transport, and disposal, among other things. Regulation as a special waste would also allow for federal enforcement. Regulation as a nonhazardous solid waste would not require the establishment of a permit program and would not be federally enforceable. Instead, states or private parties could bring lawsuits against alleged violators. EPA estimated the annualized benefits of its special waste option would be $207 to $1,342 million with $1,549 million in annualized costs and that the nonhazardous waste option would generate annualized benefits of $88 to $596 million with $606 million in annualized costs.[23] EPA does not have a schedule for issuing a final CCR regulation.

Damage to Aquatic Life: 316(b)

Coal and other types of electricity generating units often draw in large volumes of water from nearby rivers, lakes, or oceans to use for cooling, which can damage aquatic life. Thermoelectric generating units are the largest water use category by sector, using 201 billion gallons per day in

[22]The act exempted waste generated primarily from the combustion of coal or other fossil fuels—generally known as coal combustion residuals—from regulation as hazardous waste until EPA conducted a study and determined whether regulation as a hazardous waste was warranted. After issuing the required study (in two parts, the first in 1988 and the second in 1999), EPA determined in 1993, and again in 2000, that regulation of coal combustion residuals as a hazardous waste was unwarranted.

[23]These estimates refer to EPA's scenario assuming CCR would not change the beneficial use of coal combustion residuals. EPA also estimated benefits for two other scenarios. The scenario EPA considers to be the most likely assumes that CCR would increase beneficial use, and EPA estimated the annualized benefits of its special waste option would be $6,526 to $7,646 million and that the nonhazardous waste option would generate annualized benefits of $2,616 to $3,125 million. In a scenario where CCR decreases beneficial use, EPA estimated there would be negative annualized benefits for its special waste option (additional costs) of $17,270 to $16,149 million, and that the nonhazardous waste option would generate annualized benefits of $88 to $596 million.

2005, the most recent year for which data were available. Depending on how a generating unit's cooling system is designed, drawing in water for cooling can result in fish and other aquatic life being impinged—trapped—against intake screens used to filter out solid matter, as well as entrained—drawn into—the generating unit with the cooling water.[24] According to EPA, generating units kill hundreds of billions of aquatic organisms in U.S. waters each year, including fish, crustaceans, marine mammals, and other aquatic life.

Section 316(b) of the Clean Water Act requires EPA to establish standards for cooling water intake structures that reflect the best available technology for minimizing adverse environmental impact. To implement section 316(b), EPA has issued several regulations, including a regulation in 2004 that governed existing power plants with a large flow water intake.[25] However, a federal appeals court struck down the 2004 regulation. Following an appeal to the Supreme Court and settlement of other lawsuits related to the rulemaking, EPA proposed a regulation covering certain existing power plants and other facilities on April 20, 2011. Regarding impingement, the proposal would establish fish mortality requirements reflecting the best available technology based on the performance of either (1) modified traveling screens—which capture and safely return fish to water bodies—or equivalent technology or (2) reduction of the facility's water intake velocity—which would allow fish and other organisms to move away from the intake structure. Regarding entrainment, the proposal would require permitting authorities to follow a process prescribed in the regulation to determine compliance deadlines and the best available technology for entrainment controls on a site-specific basis based on consideration of several specific factors. These factors include the quantified and qualitative social benefits and costs of available control options and impacts on electricity reliability. EPA estimates that approximately 45 percent of the nation's generating

[24]Using water for cooling may also result in significant water use, and the discharge of cooling water that has been warmed from the plant process can raise the temperature of receiving water bodies.

[25]EPA first issued a regulation implementing section 316(b) in 1976, but that regulation was struck down by a federal appeals court in 1979. EPA has issued two other regulations implementing section 316(b) that are currently in effect: the Phase I regulation that governs new power plants and manufacturing facilities and the Phase III regulation that governs new offshore oil and gas facilities.

capacity would be affected by the proposed regulation.[26] As a result of regulating cooling water intake structures, EPA estimates increased harvests in recreational and commercial fisheries, improved ecosystem function, and reduced harm to threatened and endangered species, among other benefits. EPA estimated the annualized benefits of its proposed regulation to be $18 million with costs of $397 million. EPA is required by a settlement agreement to sign a final regulation no later than July 27, 2012.

Planning and Day-to-Day Actions Involved in Maintaining Electric Reliability

Electric reliability refers to the ability to meet the needs of end-use customers even when unexpected generating equipment failures or other factors affect the electricity system.[27] Reliability challenges can arise in multiple ways:

- *Resource adequacy challenges.* These arise when there are inadequate resources—generation, transmission, and others—to meet the electricity needs of end-use customers. To avoid resource adequacy challenges, system planners typically take steps to ensure that generating capacity exceeds the maximum expected demand by a certain margin, referred to as a “reserve margin.”

- *System security challenges.* These arise because of a disturbance, such as an electrical short, or the loss of a system component, such as a generating unit that is needed at a specific location to maintain the electricity grid’s voltage and frequency or to help restart the electricity system in the case of a blackout. To avoid system security challenges, system operators make real-time changes in the operation of the electricity system, for example, by increasing or decreasing the amount of electricity generated in particular locations

[26]This proposed regulation applies to existing power generating and manufacturing facilities, as well as new units at existing facilities, which have a design intake flow of more than 2 million gallons of water per day and use at least 25 percent of the water withdrawn exclusively for cooling purposes. The proposed regulation would also apply to oil-fueled, gas-fueled, and nuclear generating units that meet those requirements. EPA estimated that 559 fossil fuel electricity generating facilities would be subject to this regulation.

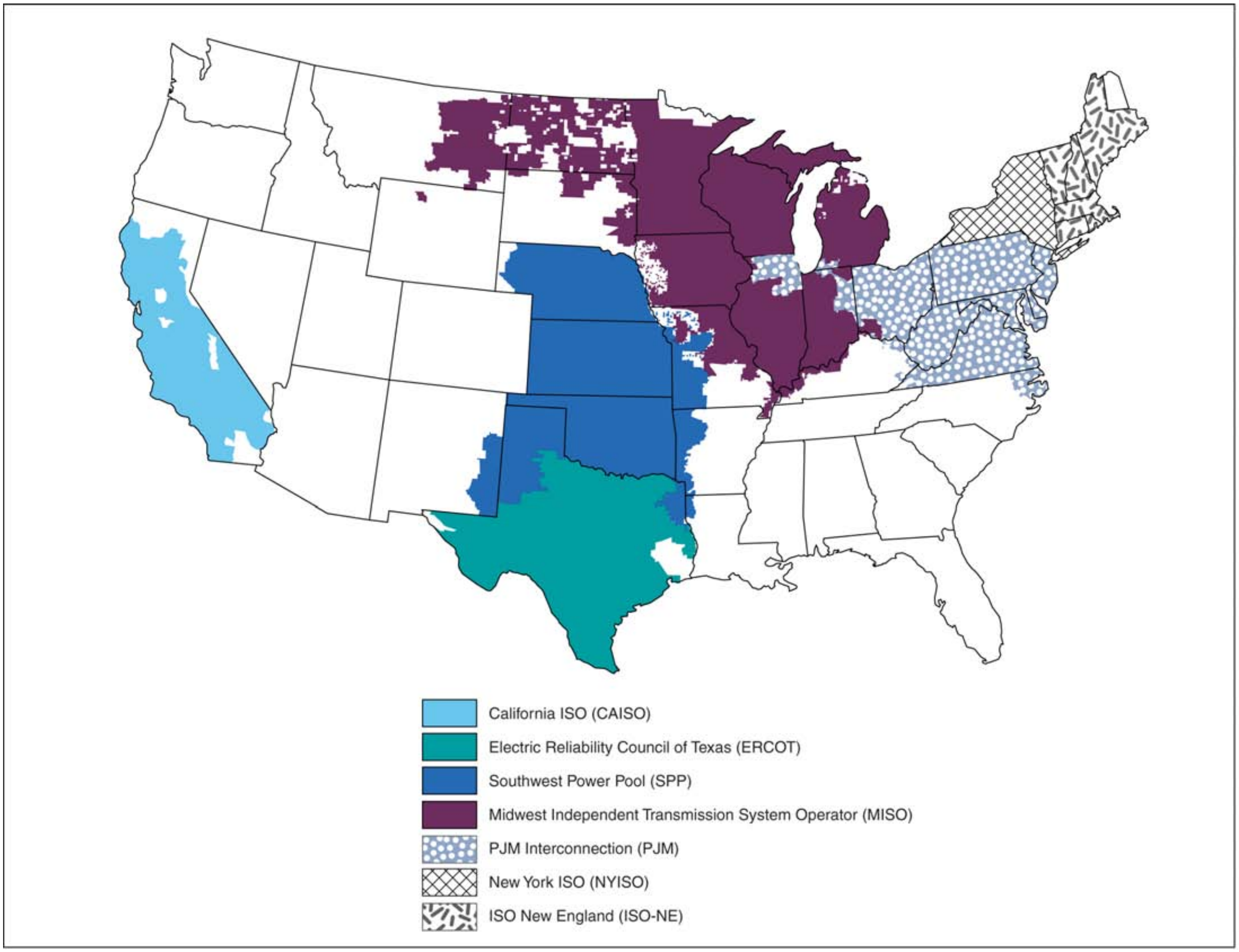
[27]We use the term electricity grid to refer to an interconnected regional network of transmission lines and the term electricity system to refer to the electricity grid together with generating units used to provide electricity to customers.

or by changing power flows on the transmission system in order to maintain suitable operating conditions.

System planners attempt to avoid reliability problems through advance planning of transmission and, in some cases, generation resources. The role of a system planner can be carried out by individual power companies or regional entities called Regional Transmission Organizations (RTO).[28] Figure 3 shows the territories of the seven RTOs in the United States. System planners' responsibilities include analyzing expected future changes in generation and transmission assets, such as the retirement of a generating unit; customer demand; and emerging reliability issues. For example, once a system planner learns that a power company intends to retire a generating unit, the system planner generally studies the electricity system to assess whether the retirement would cause reliability challenges and identify solutions to mitigate any impacts. The solutions could be in the form of replacement capacity (generation or demand-side resources) and new transmission lines or other equipment, each with its own associated permitting and construction timelines.

[28]Independent operators of the transmission system can be referred to as RTOs or Independent System Operators (ISO). RTOs and ISOs have similar functions, including operating the transmission system and longer-term regional planning, but ISOs tend to be smaller in geographic size or—for the ISOs in Texas and Canada—not subject to FERC jurisdiction over rates and tariffs. For the purposes of this report, we use the term RTOs to refer to both RTOs and ISOs.

Figure 3: U.S. Regional Transmission Organizations



Sources: FERC; Map Resources (map).

When reliability challenges cannot be avoided through prior planning, system operators take measures to resolve the problem by rebalancing supply and demand. The role of the system operator is also fulfilled by different entities, including individual power companies and RTOs. In the event of an urgent reliability challenge, system operators may take immediate steps to lower demand through public appeals to reduce use; interrupting or lowering electricity supply to customers who have negotiated prior agreements with the power company, which are referred to as reliability-driven demand-response programs; as well as rotating blackouts of limited duration. For example, during a period of sustained high summer temperatures in 2011, the system operator in Texas called upon the public to reduce electricity use during hours of peak demand to prevent the need for rotating blackouts. When reliability challenges cannot be adequately managed by system operators, unplanned, uncontrolled interruption of customer's electricity use can occur. These interruptions may be confined to a localized area or widespread. For example, in August 2003, an electricity blackout affected millions of people across eight U.S. states and parts of Canada when, among other things, system operators were unable to keep outages in northern Ohio from cascading to interconnected portions of the electric grid. In some areas, power was lost for several days.

Federal and State Government Roles in Electricity Markets

The potential impact of retrofits and retirements on electricity prices and reliability is generally overseen by the federal regulator, FERC; state regulators, including state public utility commissions; and others.[29]

Prices

At the federal level, among other things, FERC is responsible for ensuring that the rates, terms and conditions of services for wholesale electricity sales and transmission in interstate commerce—which includes wholesale electricity prices—are just and reasonable and not unduly discriminatory or preferential.[30] In some parts of the country, FERC does this by overseeing the design and operation of organized electricity markets—markets for electricity and other services intended to promote the reliable management of the grid—to ensure these markets are competitive and will result in just and reasonable electricity prices.[31]

[29]Others involved in power company oversight may include municipal city councils for municipal power companies and boards of directors for cooperative power companies.

[30]For the purposes of this report, we use "prices" to refer to the price of both wholesale and retail electricity consumed by businesses and households. Wholesale prices are generally determined in organized markets by the balance of supply and demand or may be negotiated directly between a seller and a buyer. Though FERC has a role in regulating wholesale prices for much of the electricity industry, it does not set wholesale prices or transmission rates charged by entities such as municipal utilities or most electric cooperatives. Furthermore, retail prices—also referred to as electricity rates—are generally determined by regulators, such as public utility commissions. FERC does not regulate or set retail electricity prices.

[31]The Public Utility Commission of Texas, rather than FERC, regulates the design and operation of the electricity markets in much of Texas.

Organized markets are administered by RTOs, the same independent entities that serve as system planners and operators in some regions. These electricity markets are designed to ensure an adequate supply of electricity at reasonable prices, and the markets are routinely examined by independent entities and FERC to ensure they are competitive and free of manipulation.

As a part of its responsibility for ensuring just and reasonable rates, FERC has broad authority to oversee RTO rules related to electricity transmission, markets, and other areas. These rules may include requirements about how the transmission planning process is managed, the terms and conditions under which transmission service is provided, when and how the operator of a generating unit should notify the RTO of a planned retirement, and steps the RTO will take in scheduling outages, among other things. For example, RTOs typically require power companies to notify them when the companies plan to retire a generating unit. The time frame for this notification generally varies from 45 days to approximately 180 days.[32] RTOs have an internal process in which stakeholders review, modify, and may vote on proposed changes to rules. If changes are agreed upon by the RTO's stakeholders—power companies, transmission owners, and users of electricity, among others—the RTO may propose them to FERC for approval.[33] FERC conducts its own review of proposed changes to RTO tariffs and market rules to ensure they promote just and reasonable rates including, where relevant, reliability requirements. In some cases, FERC may also proactively review RTO market rules and order any changes to ensure they are just, reasonable, and not unduly discriminatory or preferential. FERC is also responsible for examining whether reliability must-run agreements—agreements to provide nonmarket based payments to power companies with generating units that are not economical to operate but are critical to the reliability of the electricity grid—are at reasonable rates. These

[32]Some RTOs have developed markets, called capacity markets, which provide them with information about what resources are expected to be available in the future so they can plan accordingly. For example power companies seeking to retire a generating unit in ISO New England—an RTO that operates in a six-state region in the Northeast—submit a retirement request during the forward capacity market 3 years in advance of their requested retirement date. According to ISO New England officials, the region does not have a separate retirement notification process for power companies.

[33]According to FERC, RTOs have some authority to propose rule changes at FERC without broad stakeholder approval.

payments would cover the cost of keeping such units operational past when companies were planning to retire them.

The role of state governments in overseeing electricity prices varies across the country. In some areas, referred to as "traditionally regulated markets," state public utility commissions—which generally aim to ensure retail electricity rates are just and reasonable—review power companies' requests to recover the costs of investments in new generating units, distribution lines and other system upgrades.[34] Once a state public utility commission approves a power company's request, consumer retail prices are adjusted to recover the power companies' costs plus a rate of return.[35] For companies in traditionally regulated markets, their investments in controls to comply with EPA regulations would have to be approved by public utility commissions for the companies to adjust their rates to include these costs. In other parts of the country, referred to as "restructured markets," electricity is sold by multiple companies competing with each other. In these areas, public utility commissions play a more limited role in overseeing generation. Consumers pay competitive retail electricity rates based on the price of electricity as determined in FERC-regulated wholesale markets.[36] Many electricity generating companies have received authority from FERC to sell power at market-based rates and, in restructured markets, these companies would aim to recover the costs of any investments made to comply with EPA regulations through wholesale sales of electricity, but their ability to do so depends on overall supply and demand conditions, which determine the prices they can receive.

[34]About 40 percent of the population lives in states and the District of Columbia that EIA classifies as having restructured their retail markets: Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, and Texas. The remaining population lives in states that, according to EIA, have suspended their restructuring activities or have not restructured. We did not examine how EIA determined the status of restructuring in these states.

[35]Rates set by commissions may vary by customer classes (e.g., residential, commercial and industrial), as well as by the amount of electricity consumed.

[36]In addition to the market-determined generation component of their electric bill, consumers in these areas also pay a regulated rate for transmission and distribution.

Reliability

Under the Energy Policy Act of 2005, FERC is responsible for approving and enforcing standards to ensure the reliability of the bulk power system. FERC certified NERC to develop and enforce these reliability standards, subject to FERC review.[37] These standards outline general requirements for planning and operating the bulk power system to ensure reliability. For example, one reliability standard requires that system planners plan and develop their systems to meet the demand for electricity even if equipment on the bulk power system, such as a single generating unit or transformer, is damaged or otherwise unable to operate. With respect to MATS, EPA has stated that it will rely on the advice and counsel of reliability experts, including FERC, to identify and analyze reliability risks when owners request a Clean Air Act administrative order to provide units with up to an additional year for compliance with MATS. FERC recently issued a policy statement detailing how it intends to provide advice to EPA on such requests.[38]

In general, neither FERC or NERC, nor the system planners can require companies to build generation or compel existing generation to operate, but DOE can order the generation of electricity in limited circumstances. Specifically, in certain emergencies, section 202(c) of the Federal Power Act authorizes DOE to order, among other things, the generation of electricity that in its judgment will best meet the emergency and serve the public interest. DOE has used this authority in the past to, among other things, ensure electricity could be provided to the District of Columbia in the event of a transmission line failure, as well as to provide electricity to customers during the California energy crisis. Furthermore, some state public utility commissions may require power companies to ensure they can provide adequate levels of generation to meet the demand of customers in their service territory.

[37]For standards to be legally enforceable, FERC must approve them.

[38]See FERC "Policy Statement on the Commission's Role Regarding the Environmental Protection Agency's Mercury and Air Toxics Standards," Docket No. PL12-1-000 (May 17, 2012).

Power Companies Are Expected to Retrofit or Retire Units and Take Other Actions

According to available information, there is uncertainty regarding how power companies will respond to the four key EPA regulations, though companies are expected to retrofit most coal-fueled generating units with controls, retire other units, and take additional actions.

It Is Uncertain How Power Companies Will Respond to Key EPA Regulations

It is unclear how power companies will respond to the four key EPA regulations, in part because there is uncertainty about the regulations themselves and other factors affecting the industry, including future natural gas prices. Analysts that have studied how power companies may respond to the regulations have made different assumptions regarding these factors, which affect power companies' assessments of whether to make additional investments in coal-fueled generating units such as investments that may be needed to respond to the four key regulations.[39]

Regarding the regulations, the requirements and deadlines they may establish for generating units are somewhat uncertain, especially for the proposed regulations. This is because the final CCR and 316(b) regulations might differ from the proposed regulations and because of current and potential future legal challenges. For example, CSAPR and MATS—the two regulations that have been finalized—face legal challenges and may change depending on how the court rules. In addition, some of the regulatory requirements, such as some aspects of 316(b), will not be specified until the relevant permits are issued. Furthermore, several bills have been introduced in Congress that would affect some or all of the regulations. Some power companies may delay taking actions to respond to these regulations until there is additional certainty about their final regulatory requirements.

Several other factors also contribute to the uncertain environment in which power companies will respond to the new regulations. Among these is uncertainty about the future demand for electricity. EIA projects that demand for electricity will grow slowly over the next few years. This means power companies may be less inclined to make, and state electricity regulators may be less willing to approve of, investments in

[39]GAO has ongoing work on the views of stakeholders of factors that may affect the future use of coal to generate electricity.

electricity generating units that may not be needed as often. On the other hand, if the economic recovery is more robust, there could be more electricity demand than expected, which might increase the need for additional generating capacity in some areas. Another factor that contributes to uncertainty is the price of fuels. Natural gas prices have decreased in recent years, and coal prices have increased, narrowing the historical cost advantage of using coal to produce electricity in some parts of the country. As a result of these changing prices, among other things, the use of natural gas to produce electricity has increased and is expected to continue to increase. For example, EIA recently projected that the use of natural gas to produce electricity in 2012 could increase by 24 percent, and that, in turn, electricity generation from coal could decline by 15 percent.[40] However, some stakeholders we interviewed raised concerns about the prospects for continued low natural gas prices, citing the potential increased future use of natural gas for electricity or more strict regulation of natural gas production that could affect the long-term outlook for domestic natural gas production and prices.

Another factor that contributes to uncertainty is the increased focus on renewable energy production and other potential future regulations. In recent years, there have been federal and state efforts to encourage the development of renewable energy sources—particularly wind and solar—to produce electricity. For example, 30 states have laws or regulations requiring power companies to increasingly rely on renewable sources for electricity.[41] These and other policies may contribute to generation from renewable sources increasing from 10 percent in 2010 to 16 percent of total electricity generation by 2035, potentially diminishing the demand for electricity from fossil fuels, including coal, in the future. Some stakeholders we met with noted that there is uncertainty about future environmental requirements, in particular those aimed at reducing carbon dioxide emissions to address climate change.[42] Such future requirements

[40]U.S. Energy Information Administration, *Short-Term Energy Outlook* (May 2012).

[41]These states are: Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Illinois, Iowa, Kansas, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, Washington, West Virginia, and Wisconsin.

[42]Under the terms of a settlement agreement, EPA was required to propose and finalize new source performance standards for greenhouse gas emissions from existing electricity generating units. In April 2012, EPA proposed standards for certain new electricity generating units and stated that it would propose standards for existing units at an appropriate time.

could affect the attractiveness of additional investments by power companies in existing coal-fueled generating units because coal-fueled units are more carbon intensive than other forms of generating electricity. As we have previously reported, on average, coal-fueled units produced twice as much carbon dioxide as natural gas units in 2010.[43]

Power Companies Are Expected to Retrofit Many Generating Units, Retire Others, and Take Additional Actions

According to available information, power companies are projected to retrofit many coal-fueled generating units with environmental controls and retire some other units, as well as take additional actions to respond to the four key EPA regulations.

- *Retrofit many coal-fueled generating units.* All 12 of the studies we reviewed suggest that power companies may retrofit many coal-fueled generating units with new or upgraded controls to respond to the four key regulations. EPA's analyses and two other studies we reviewed report national projections of how companies may reduce emissions of air pollutants to meet the finalized MATS and CSAPR requirements. Projections in these studies suggest that one-third to three-quarters of all coal-fueled capacity could be retrofitted or upgraded with some combination of controls, including the following: (1) fabric filters or electrostatic precipitators to control particulate matter; (2) dry sorbent injection or flue gas desulfurization units—also known as scrubbers—to control SO_2 and acid gas emissions; (3) selective catalytic reduction or selective non-catalytic reduction units to control NO_x; and (4) activated carbon injection units to reduce mercury emissions.[44] Appendix IV describes these controls, how they operate, and the extent of their use among coal-fueled generating

[43]GAO, *Air Emissions and Electricity Generation at U.S. Power Plants,* GAO-12-545R (Washington, D.C.: Apr. 18, 2012).

[44]Specifically, EPA projects that MATS will lead to the installation of fabric filters on an additional 102,000 MW of capacity; upgraded electrostatic precipitators on 34,000 MW; new dry sorbent injection units on 44,000 MW of; new scrubbers on 20,000 MW (and scrubber upgrades on 63,000 MW); and activated carbon injection units on 99,000 MW 2015. EPA also projected that CSAPR will lead to retrofitted dry sorbent injection units on 3,000 MW and scrubbers on 5,900 MW by 2014. NERC (2011) projected that 576 units with 234,371 MW of capacity would retrofit by the end of 2015. A study by staff of the Bipartisan Policy Center (which we refer to as Bipartisan Policy Center, 2011) projected, in 2015, fabric filters on 516-541 units; dry sorbent injection units on 181-199 units (24,000 MW of capacity); scrubbers on 84-85 units (51,000 MW); selective catalytic reduction units on 28-34 units; and activated carbon injection units on 368-392 units. (Full citations for selected studies are listed in app. III.)

units. Two of the studies we reviewed include estimates of how power companies may respond to CCR, projecting that some companies would convert power plants from wet ash handling to dry ash handling, which uses conveyor belts or trucks to gather and transport coal combustion residuals to storage sites, since wet ash impoundments may effectively be phased out under the final CCR regulation.[45] These two studies projected that companies could convert 96-98 and 158 power plants to dry ash handling respectively.[46] For power companies to respond to the proposed 316(b) regulation, EPA estimates that approximately 224 generating units may install intake screens called modified traveling screens—screens or buckets that collect fish from the cooling intake water and return them safely to the source water body—or reduce the facility's water intake velocity to meet impingement requirements. In addition, two studies estimated how many power plants may install cooling towers to meet the proposed 316(b) entrainment requirements, projecting that 46 and 92-93 plants may do so.[47] These projections are uncertain since the proposed regulation gives permitting authorities the responsibility to set entrainment requirements on a case-by-case basis.[48] Figure 4 shows where some of these controls would be installed at a coal-fueled power plant.

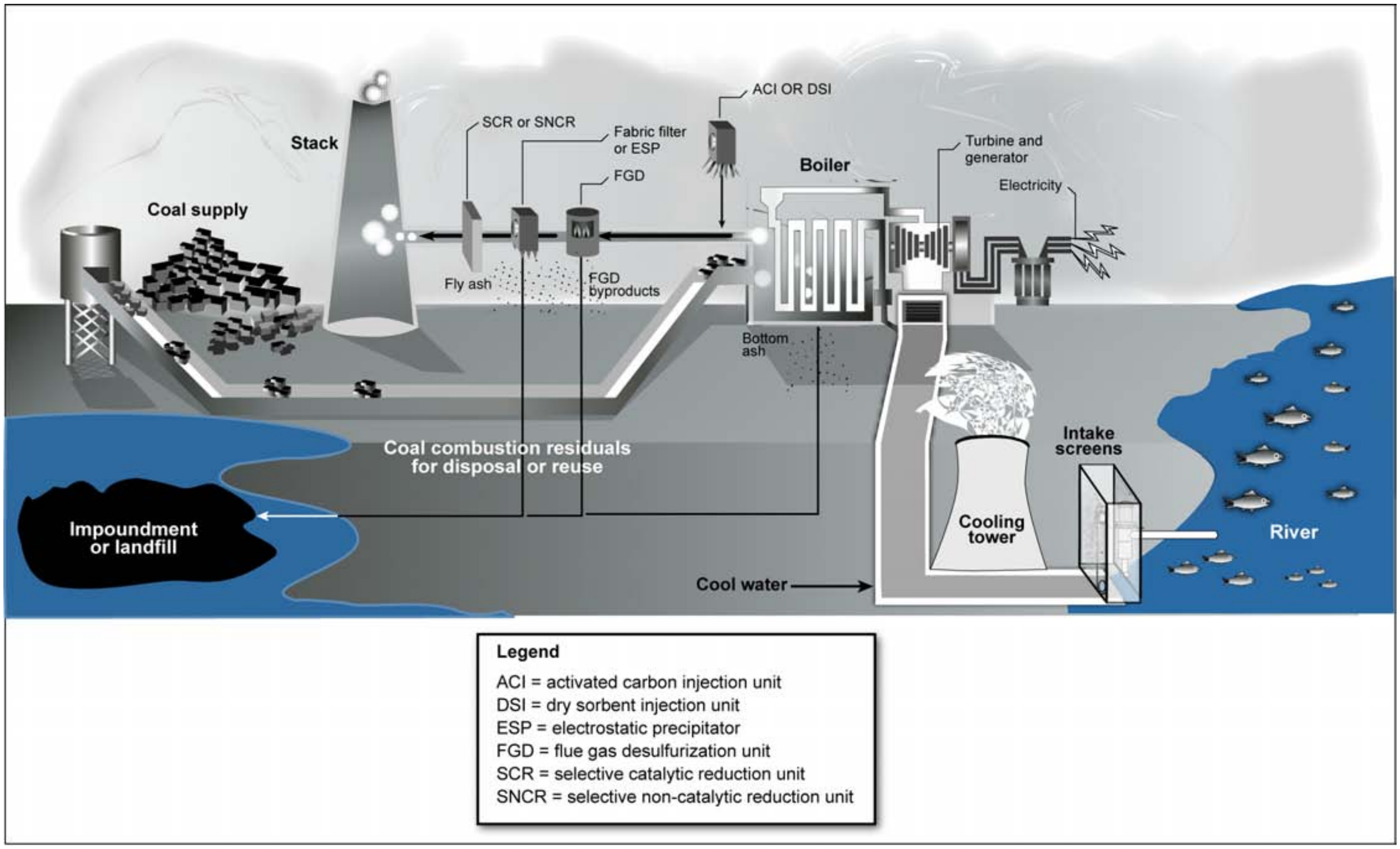
[45]Coal combustion residuals can be gathered and transported with dry handling systems or with wet systems—such as when ash and water form a slurry that flows into an ash impoundment.

[46]See Bipartisan Policy Center (2011) and EPA-CCR (2010).

[47]See NERA (2011) and Bipartisan Policy Center (2011).

[48]Some researchers have observed that studies that examined the potential implications of the four key regulations that were conducted before EPA proposed 316(b) assumed that EPA would require closed-cycle cooling towers. While acknowledging that closed-cycle cooling towers reduce impingement and entrainment mortality to the greatest extent, the proposed regulation concludes that it is not the best technology available for minimizing adverse environmental impacts on a national basis because of the following key factors: (1) potential adverse consequences to the reliability of energy delivery on the local level during the installation of cooling towers; (2) increased air emissions of various pollutants because of the additional fuel that would be burned to compensate for the energy required to operate the cooling towers and the slightly lower generating efficiency; (3) feasibility concerns and lack of land availability for placement of the cooling towers; and (4) the limited remaining useful life of some generating units. None of the study results that we cite here assumes that EPA would require closed-cycle cooling towers for all units.

Figure 4: Sample Layout of Controls at a Coal-Fueled Power Plant



Sources: GAO analysis of information from Electric Power Research Institute, Tennessee Valley Authority, and Babcock & Wilcox.

Note: This figure is intended to be illustrative, though not exactly representative, of the controls used.

- *Retire some units.* Ten of the studies we reviewed include projections of how much coal-fueled capacity power companies might retire, with three of these studies reporting national projections corresponding to all four regulations. The projections in these three studies range from power companies retiring 2 to 12 percent of coal-fueled capacity in response to the four regulations rather than installing controls.[49] Some regions may see more significant levels of retirements. For example, a study by the Midwest Independent Transmission System Operator, Inc. (MISO), an RTO that covers all or parts of 11 U.S. states and a Canadian province, projected that 18 percent of the coal-fueled capacity in the U.S. portion of its region could retire. EPA and some stakeholders we interviewed pointed out that some of these projected retirements may have occurred at some point even without the new regulations. As discussed previously, several industry trends may be contributing to the retirement of coal-fueled generating units, including relatively low natural gas prices, increasing prices for coal, and low expected growth in demand for electricity. For example, officials at an investment analysis firm highlighted a financial analysis they had conducted that found that 7 to 11 percent of coal-fueled capacity may not be economic to operate in 2012 to 2014 at expected coal and natural gas prices.[50] This capacity could be at risk of retirement unless economic conditions change. In addition, one of the studies we reviewed found that changes in expectations regarding future natural gas prices and electricity demand have an impact on projected retirements that is comparable to the effect of CSAPR and MATS.[51] At the same time, some stakeholders told us that the regulations may accelerate retirements because power companies may not want to invest in controls for units they expect to retire soon for other reasons. Several stakeholders highlighted that the units power companies may retire early are likely to be smaller, older, and less efficient units. Consistent with stakeholder views about the regulations accelerating retirements, power companies have announced their plans to retire units representing about 9 percent of coal-fueled capacity with the bulk of these retirements occurring by MATS's 2015 compliance

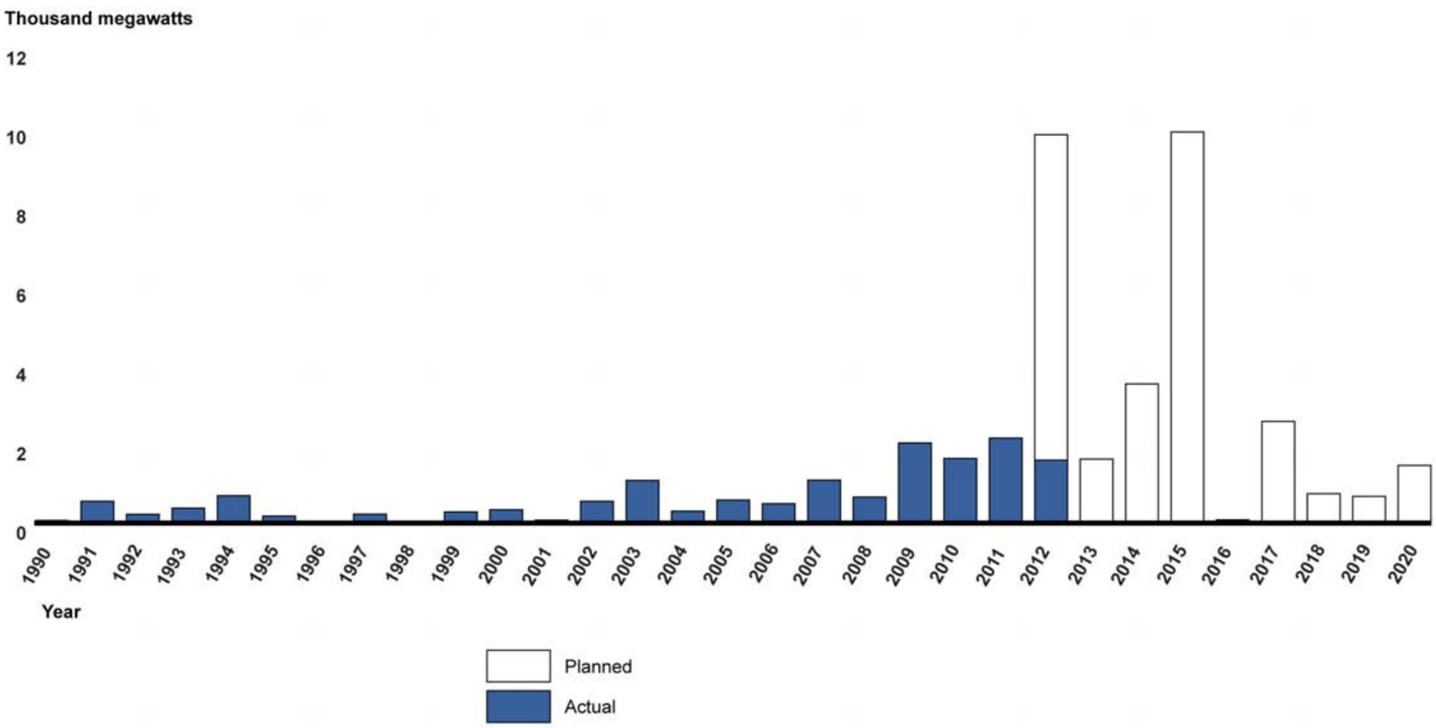
[49]See North American Electric Reliability Corporation (2011), Bipartisan Policy Center (2011), and NERA (2011). EPA expressed concerns about some of the NERA study's assumptions and said its modeling was not sufficiently transparent. Power companies are planning to retire generating units in the absence of the four regulations, but the projections we cite here attempted to distinguish retirements in response to the regulations from those that would occur in their absence.

[50]Hugh Wynne, et al. "Bernstein Commodities and Power: The Forward Prices for Coal and Gas Can't Both Be Right—How Utilities Will Arbitrage Fuel Prices in 2012" (Dec. 16, 2011).

[51]See RFF (2012).

deadline.[52] (See fig. 5.) These planned retirements include retirements for any reason, including in response to the four regulations, and would correspond to almost twice as much coal-fueled capacity as retired in the 22 years from 1990 through April 2012.

Figure 5: Capacity of Actual and Planned Coal-Fueled Generating Unit Retirements, 1990-2020



Source: GAO analysis of Ventyx data.

Note: Data on generating unit capacity refers to units with over 25 MW of net summer capacity—the generating unit's capacity to produce electricity during the summer when electricity demand for many electricity systems and losses in efficiency are generally the highest. Net capacity figures exclude output used internally for plant operations.

- *Other actions.* The studies we reviewed cited several other actions that power companies may take in response to the new regulations, including building new generating units, upgrading transmission

[52]Information on planned retirements reflect publicly reported plans as identified by Ventyx. As plans may change, actual future retirements may differ from these plans.

systems to ensure reliability, and changing how they operate their units. First, several of the studies we reviewed project that power companies may increasingly use natural gas to produce electricity as they retire coal-fueled units and because remaining coal units may become somewhat more expensive to operate. Increased generation from natural gas could come from a combination of existing natural gas units being used more often and new natural gas units being built. Second, power companies may also upgrade transmission systems to address reliability issues that arise due to units' retirements, which may include relatively straightforward incremental upgrades to existing transformers or circuit breakers, as well as more significant enhancements such as new transmission lines. Third, EPA projects that power companies may also change how they operate their universe of generating units in response to the regulations. This is particularly likely in response to CSAPR, which would give power companies flexibility in deciding how to meet emissions limitations, including by running more polluting units less often or purchasing emissions allowances.

Actions Taken by Power Companies Will Likely Increase Electricity Prices and May Contribute to Reliability Challenges in Some Regions

Available information suggests the actions power companies take to respond to the four key regulations will have costs, and some may be challenging to complete by the regulations' compliance deadlines. In addition, these actions may have varied implications across the country—increasing electricity prices in some regions and contributing to some potential reliability challenges.

Estimated Costs of Power Companies' Actions in Response to Four EPA Regulations

Two of the studies we reviewed reported national estimates of the total costs of actions power companies may take in response to the four key EPA regulations, projecting from $16 billion to $21 billion in additional annual costs.[53] EPA analyzed each regulation individually and projected annual compliance costs of $10.2 billion for MATS, $853 million for CSAPR, $600 million to $1.5 billion for CCR depending on which option is finalized, and $397 million for 316(b).[54] According to EPA reports, in addition to operating and maintenance costs, a typical coal-fueled unit with a capacity of 700 MW could incur costs from $287 million to $351 million to install a scrubber, from $116 million to $137 million to install a selective catalytic reduction unit, and from $97 million to $114 million to install a fabric filter.[55] Other controls are less expensive, and a 700 MW unit could incur $22 million to $43 million to install a dry sorbent injection unit or $4 to $5 million for an activated carbon injection unit, according to EPA reports.[56]

Additional costs could be incurred to build or acquire new generating capacity or to upgrade transmission systems due to unit retirements. For example, MISO estimated that building new generating capacity in its

[53]Specifically, the Bipartisan Policy Center study projected annualized costs of $16 billion in 2015 and $20 billion in 2025. NERA Economic Consulting estimated additional annual costs of $21 billion on average over the 2012-2020 period, with a total net present value of $130 billion. EPA expressed concerns about some of the NERA study's assumptions and said its modeling was not sufficiently transparent. It is important to note that these studies made different assumptions about the regulations that can affect their findings. For example, while EPA has stated that it expects power companies to comply with 316(b) over a 15-year period from 2013-2027, NERA assumed costs were incurred in 2015. NERA's assumption may overstate costs. At the same time, both NERA and the Bipartisan Policy Center's analysis assumed that EPA would finalize the solid waste option for CCR. Costs may be higher if EPA instead finalizes the special waste option.

[54]EPA officials said that it would be inappropriate to add together its cost estimates from these regulations because of differences in baselines and analysis years. EPA did not provide an estimate of the overall impact of the four regulations.

[55]EPA, *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model,* EPA#430R10010 (Washington, D.C.: August 2010) (http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html) and EPA, *Documentation Supplement for EPA Base Case v4.10_PTox-Updates for Proposed Toxics Rule*, EPA#430-R-11-006 (Washington, D.C.: March 2011) (http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/suppdoc.pdf).

[56]These costs do not include costs that may be associated with retrofitting or upgrading particulate matter controls that may be needed for dry sorbent or activated carbon injection units.

region to offset capacity lost from unit retirements could cost from $2 billion to $10 billion and that an additional $580 to $880 million in transmission upgrades could be required to maintain reliability criteria after potential unit retirements in net present value terms. MISO's study is the only one we identified that estimated potential transmission investments needed to maintain reliability.

Some Actions May Be Challenging to Complete by Compliance Deadlines

Assessments by EPA and DOE suggest that much of the electricity industry may be able to complete actions by the compliance deadlines. In their assessments, EPA and DOE compared past coal-fueled generating unit retrofits to the MATS compliance deadline. DOE found that, assuming prompt action by regulators and generators, the timelines associated with retrofits and new construction are generally comparable to EPA's regulatory deadlines.[57] EPA reported that a reasonable, moderately paced effort would result in the majority of needed retrofits being installed by 2015 with the possibility of some retrofits needing up to an additional year for completion.[58] In addition, EPA's analysis stated that past experience may not reflect industry's ability to deploy controls at a faster pace in the future using overtime, additional off-site modularization and prefabrication.[59]

At the same time, power company representatives and other stakeholders suggested that it might be challenging to complete retrofits or retirements by the compliance deadline for MATS in some cases. In this regard, an analysis by the Utility Air Regulatory Group, a voluntary group whose members include power companies, found that about 30 percent of projects to install fabric filters might be completed by the 2015 MATS compliance deadline and almost 70 percent of projects might be

[57]DOE, *Resource Adequacy Implications of Forthcoming EPA Air Quality Regulations* (December 2011).

[58]EPA's analysis examined the overall capacity of the industry to design, supply, and install equipment but did not examine the availability of specific resources or when retrofit projects may begin. EPA found that, given past experience deploying controls and building new generating capacity, sufficient engineering and other capacity would be available to meet these needs. See: EPA, *An Assessment of the Feasibility of Retrofits for the Mercury and Air Toxics Standards Rule* (Dec. 16, 2011).

[59]Modularization and prefabrication refers to assembling individual components of complex controls off-site and combining and attaching these assemblies to the generating unit to reduce on-site construction times.

completed by the 2016 deadline, with the 1-year extension available from permitting authorities.[60] EPA's study of the final MATS regulation indicates that fewer fabric filters may be needed than were assumed by the Utility Air Regulatory Group, and the group's results suggest that it may be possible to complete these by the 2016 deadline with the 1-year extension. Similarly, actions to mitigate capacity loss and other challenges due to generating unit retirements could take time as they could involve building new generating units or upgrading transmission systems. If these actions cannot be completed before compliance deadlines, a reliability challenge could arise unless steps are taken to keep generating units that are critical for the reliability of the electricity system from retiring. There have been examples of efforts to conduct transmission upgrades to address reliability challenges that have taken longer than the 4 years that may be available to meet the MATS compliance deadline assuming a 1-year extension. For example, transmission upgrades were necessary to allow several generating units with total capacity of 790 MW to retire at the Benning Road and Buzzard Point power plants on the Potomac Electric Power Company system, which serves 788,000 customers in Maryland and the District of Columbia. In 2007, the plants’ owner notified the system planner of its desire to retire the units by mid-2012. The needed transmission upgrades, including new transformers and circuits, are expected to be completed in mid-2012.

Retrofits of generating units, transmission system upgrades, and the construction of new generating units can be major engineering undertakings, and several power company representatives and other stakeholders we interviewed said that completing some of these undertakings by compliance deadlines may be challenging in some cases. Stakeholders expressing concerns highlighted the following three reasons meeting these deadlines could be challenging, particularly for MATS compliance:

- *Regulatory approvals can take time.* Retrofits, transmission line upgrades, and construction of new generating units will require

[60]The analysis assessed the rate at which fabric filters can be deployed for MATS compliance, assuming fabric filters may be required on 533 generating units representing 166,000 MW of capacity. See: Utility Air Regulatory Group, *Attachments to the Comments of the Utility Air Regulatory Group, Volume 4*, Docket EPA-HQ-OAR-2009-0234, (Washington, D.C.: Aug. 4, 2011).

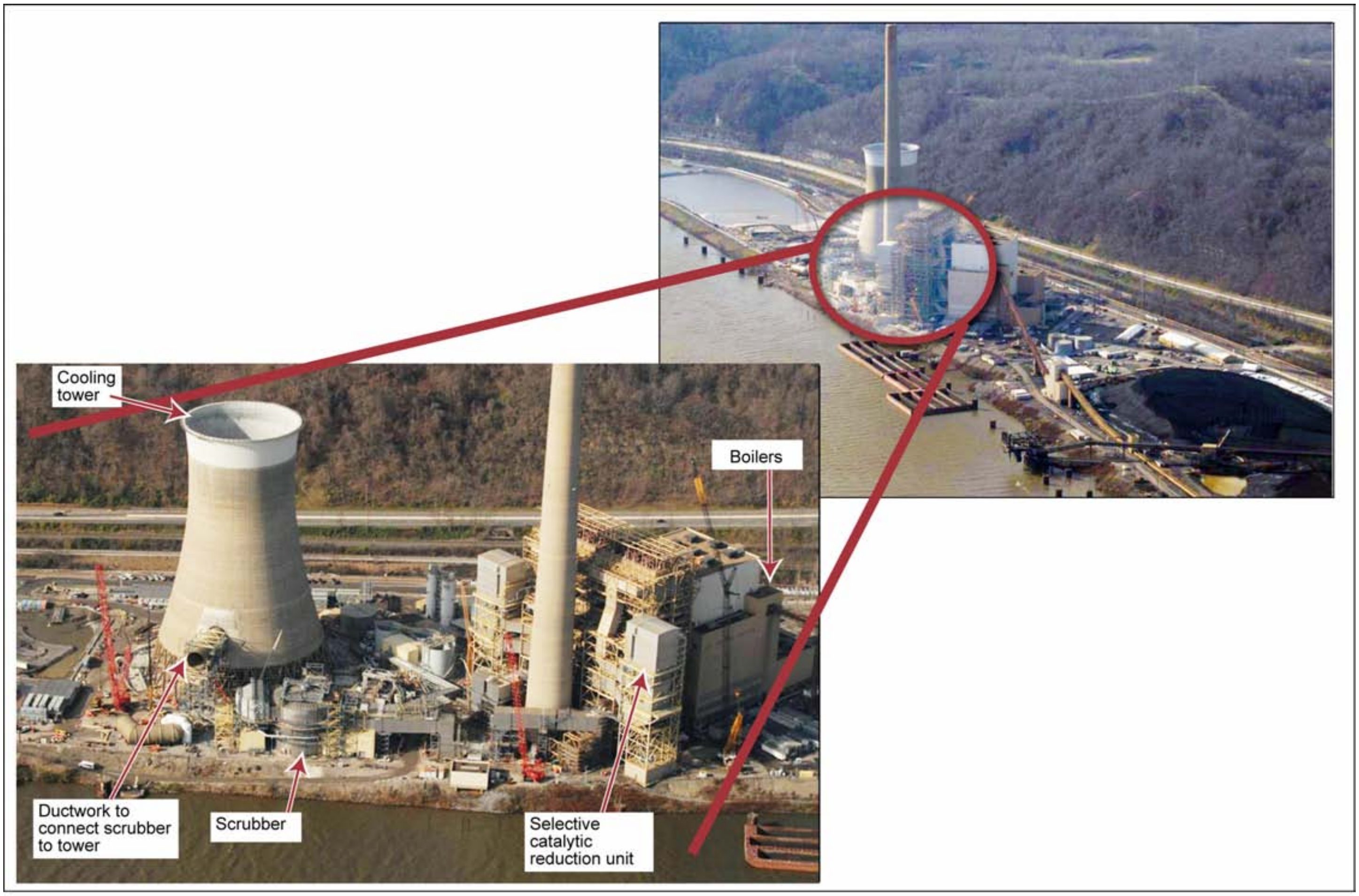
various state and local regulatory approvals, which may include construction permits and modifications of air pollution permits, which can extend the completion time of such projects.[61] In traditionally regulated markets, power companies that decide to undertake a retrofit or new construction may also need to obtain a review by the state utility commission in order to include associated costs in electricity rates. Some of these approvals can be pursued concurrently with or be obtained after design, construction, and start-up, but some may extend completion times.[62]

- *Site-specific concerns for retrofits.* In addition, some of the power company representatives we interviewed told us that power plants may have site-specific physical constraints that can slow completion of work. For example, according to representatives at one company, it took the company about 5 years to install fabric filters on four units at one plant, in part because the site did not have space to place the needed controls. The fabric filter for one of the units had to be constructed 1,200 feet away and connected via ductwork. Figure 6 illustrates another power plant with site-specific concerns, constrained by a river on one side and a highway and mountain on the other. Officials from the power company owning this plant told us that they generally construct a separate new stack for retrofitted scrubbers, but this was not possible due to space constraints at this site. Instead, the power company is installing ductwork from the scrubber through the cooling tower in order to use the cooling tower as a stack.

[61]The construction of new generating units and certain retrofits on existing units may require various types of air permits. For example, power companies may need to go through New Source Review, a preconstruction permitting process that establishes emissions limits and requires the use of certain emissions control technologies. Power plants will only need a major New Source Review permit if the retrofit is a major modification—a physical or operational change that would result in a significant net increase in emissions of a regulated pollutant—which is determined on a case-by-case basis. States may require minor New Source Review permits for retrofits that are not major modifications.

[62]An examination of over 100 recent preconstruction pollution control retrofit approvals before public utility commissions in 10 states found that the average approval time across all cases was 7 months, though it took over a year for six cases. M.J. Bradley & Associates LLC, "Public Utility Commission Study," Prepared for SRA International, Mar. 31, 2011.

Figure 6: Installation of a Scrubber at the Cardinal Plant in Brilliant, Ohio



Source: American Electric Power Company, © 2011 American Electric Power Company, Inc.

- *Supply chain concerns.* Some power company representatives and other stakeholders stated that, because of the large number of potential retrofits, they had concerns about the availability of specific skilled laborers or equipment needed to install some controls. The installation of some controls could entail significant retrofit efforts industry-wide. For example, according to EPA, companies could install fabric filters on an additional 102,000 MW of coal-fueled capacity in response to MATS. This is almost double the coal-fueled capacity that currently has fabric filters. The simultaneous installation of air pollution controls has strained supply chains in the past. For example, EPA stated that, from 2007 to 2008, when a significant number of power plants installed scrubbers, delays as long as 18 months occurred for plants to obtain such key engineered equipment as large pumps, motors, and chimneys that were needed. (See app. IV for additional information on the controls installed on coal-fueled units.) Some other stakeholders have said that there are sufficient resources available and did not identify concerns related to supply chain issues. EPA has stated that the controls needed to meet CSAPR and MATS are much simpler and will take significantly less time to plan, design, install, and commission than the controls that caused strains in the past.

Impacts Are Expected to Vary Across the Country

The actions power companies take to respond to the four EPA regulations are expected to affect some parts of the country less than others. First, some areas of the country, such as California, Washington, Oregon, and Maine, have little coal-fueled generation and, therefore, are expected to see little impact. In addition, CSAPR would cover 28 states in the eastern half of the United States, so generating units in the remaining states would not be affected. Second, power companies in certain areas may have already installed some of the needed controls on their coal-fueled units for a variety of reasons. For example, at least 18 states have enacted laws or regulations to limit mercury emissions from electricity generation.[63] To satisfy these state requirements, power companies with coal-fueled generating units in these states may have already installed, or be planning to install, controls that are also capable of meeting MATS limits. These states may not see many additional changes in their electricity systems. In addition, some regions have coal-fueled generating units that were built more recently, and such newer units, as we reported in April 2012, are more likely to have installed some controls that could be helpful in meeting MATS and CSAPR requirements.[64] In contrast, other areas, including the Midwest, Mid-Atlantic, and South, have higher concentrations of coal-fueled generating units that do not have control equipment needed to respond to the four key regulations. These areas are more likely to be affected by the key EPA regulations.

[63] These 18 states are Colorado, Connecticut, Delaware, Georgia, Illinois, Maryland, Massachusetts, Michigan, Minnesota, Montana, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Oregon, Utah, and Wisconsin.

[64] Under the New Source Review provisions of the Clean Air Act, generating units built after August 7, 1977 must obtain a preconstruction permit that establishes emission limits and requires the use of certain pollution control technologies. See GAO-12-545R.

Actions Would Likely Increase Electricity Prices in Some Regions

The actions power companies may take in response to the four key EPA regulations would likely increase electricity prices in some regions. Of the 12 studies we reviewed, EPA and three other entities—Resources for the Future (RFF),[65] NERA Economic Consulting, and MISO—conducted studies that project price impacts, but their results are not directly comparable because they considered different sets of the four regulations, report results differently, and examined different configurations of states in their regional analysis. EPA's analyses suggest that MATS, by itself, may increase average retail electricity prices in the contiguous United States by 3 percent in 2015 and 2 percent in 2020 and have the most significant potential price impact of the four regulations. EPA estimated that the potential impact of MATS on average retail electricity prices in 13 regions could range from about a 1 percent increase in a region covering most of California to about a 6 percent increase in a region covering Kansas, Oklahoma, and parts of New Mexico, Texas, Louisiana, Arkansas, and Missouri. Table 2 summarizes the results of EPA's studies.[66] Electricity prices are influenced by a number of other factors, including changing prices of fuels and demand for electricity. According to EPA officials, the projected price increases associated with CSAPR and MATS are within the historical range of price fluctuations, and projected future prices overall may be below historic electricity prices. EPA officials also said that the regions of the country most likely to experience larger price increases have historically had lower than average prices and that they project that postimplementation prices in these regions will remain below the national average.

[65]RFF is a nonprofit and nonpartisan organization that conducts independent research on environmental, energy, natural resource and environmental health issues.

[66]EPA officials told us that it would be inappropriate to add together its price increase estimates from these regulations because of differences in baselines and analysis years. EPA did not prepare an estimate of the overall impact of the four regulations.

Table 2: EPA Estimates of Potential Average National and Regional Retail Electricity Price Increases Due to Compliance with Four Key EPA Regulations

Regulation	Range of estimated regional price increases	Estimated national average price increase
CSAPR[a]	-0.2-3.1%	0.8%
MATS[a]	1.3-6.3%	3.1%
316(b)	0.0- 0.4%	0.1%
CCR–Solid Waste Option	0.0-1.2%	0.2%
CCR–Special Waste Option	0.0-5.6%	0.8%

Source: GAO analysis of EPA information.

Note: Estimates refer to impacts for different years—2014 for CSAPR, 2015 for MATS and 316(b), and incremental regulatory costs compared with electricity prices in 2009 for CCR.

[a]Estimates are for regions in the contiguous United States.

NERA examined all four regulations and estimated that average electricity prices from 2012 to 2020 may be only slightly affected in the Northwest (0.1 percent increase), although they could increase by an average 13.5 percent in Kentucky and Tennessee—states more dependent on electricity generated from coal.[67] The RFF study examined the combined impact of MATS and CSAPR and projected a 0.6 percent increase in electricity prices in 2020. The RFF study also estimated that other factors, including falling natural gas prices and other trends, may be contributing to declining future electricity prices that may offset some or all of the price increases due to the EPA regulations.[68] MISO looked at the price implications of all four regulations in its region, projecting a 7 to 7.6 percent retail price increase.

Electricity prices may increase because the investments associated with the actions power companies take to respond to the EPA regulations, and any increases in the costs of generating electricity, would be passed on to customers to varying extents. In traditionally regulated markets, power companies would submit rate cases to their public utility commissions

[67]EPA expressed concerns about some of the NERA study's assumptions and said its modeling was not sufficiently transparent.

[68]While EIA's study does not estimate the impact of the EPA regulations on prices, it projects that average retail electricity prices may decline from 9.8 cents per kilowatt-hour in 2010 to 9.2 cents per kilowatt-hour in 2019, in part due to declines in the prices of natural gas.

requesting approval to increase prices to cover costs associated with responding to the regulations. If a state public utility commission finds these costs are prudent, prices would be increased accordingly to recover these costs. For example, the public utility commission in Kentucky approved environmental compliance plans for two power companies to install controls and convert to dry ash handling related to CSAPR, MATS, and CCR, among other actions.[69] The public utility commission of Kentucky stated that these plans may increase residential electricity bills by 18 percent for one company and by 10 percent for another—about $16 and $7 per month for an average customer, respectively, by 2016. However, increased costs may not be fully passed on to consumers in restructured markets where generating units are not owned by a state-regulated utility. This could occur because prices paid for electricity generation are set by FERC-overseen competitive markets. In these instances, power companies, rather than consumers, may absorb some, or all, of these costs. In such markets, power companies bid to provide electricity at a certain price. These bids are accepted from lowest to highest until all demand for electricity is met. The price of the last bid accepted to meet demand generally establishes the market price. If this price-setting bid is from a coal-fueled unit that is more expensive to operate because of controls or from a unit that is more expensive to operate than a retired coal-fueled unit, electricity prices are likely to rise. If the price-setting bid is from a generating unit that is not affected by the regulations and that would have set the price in the absence of the regulations, then prices are likely to remain the same.

Likewise, other investments to address any potential reliability challenges could also increase prices. For example, as a power company retires generating units, the relevant system planner identifies whether the retirements would cause reliability challenges. If there are reliability

[69]The approved plans also include other changes that affect price implications of these investments, such as a reduction in the rate of return the companies may earn on their investments and a 1 cent increase in a monthly charge to fund a home energy assistance program. See: Commonwealth of Kentucky Public Service Commission, "PSC Accepts Settlement in KU and LG&E Environmental Compliance Cases," (Frankfort, KY: Dec. 15, 2011); Commonwealth of Kentucky Public Service Commission, "Order: Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of its 2011 Compliance Plan for Recovery by Environmental Surcharge," Case No. 2011-00161; and Commonwealth of Kentucky Public Service Commission, "Order: Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of its 2011 Compliance Plan for Recovery by Environmental Surcharge," Case No. 2011-00162.

challenges, the system planner would identify actions to mitigate the challenge, and costs incurred to build or acquire new generating capacity or to upgrade transmission systems could result in costs to consumers. In general, costs associated with transmission system upgrades would be passed on to consumers through regulated prices.

Actions May Not Cause Widespread Reliability Concerns but May Contribute to Challenges in Some Areas

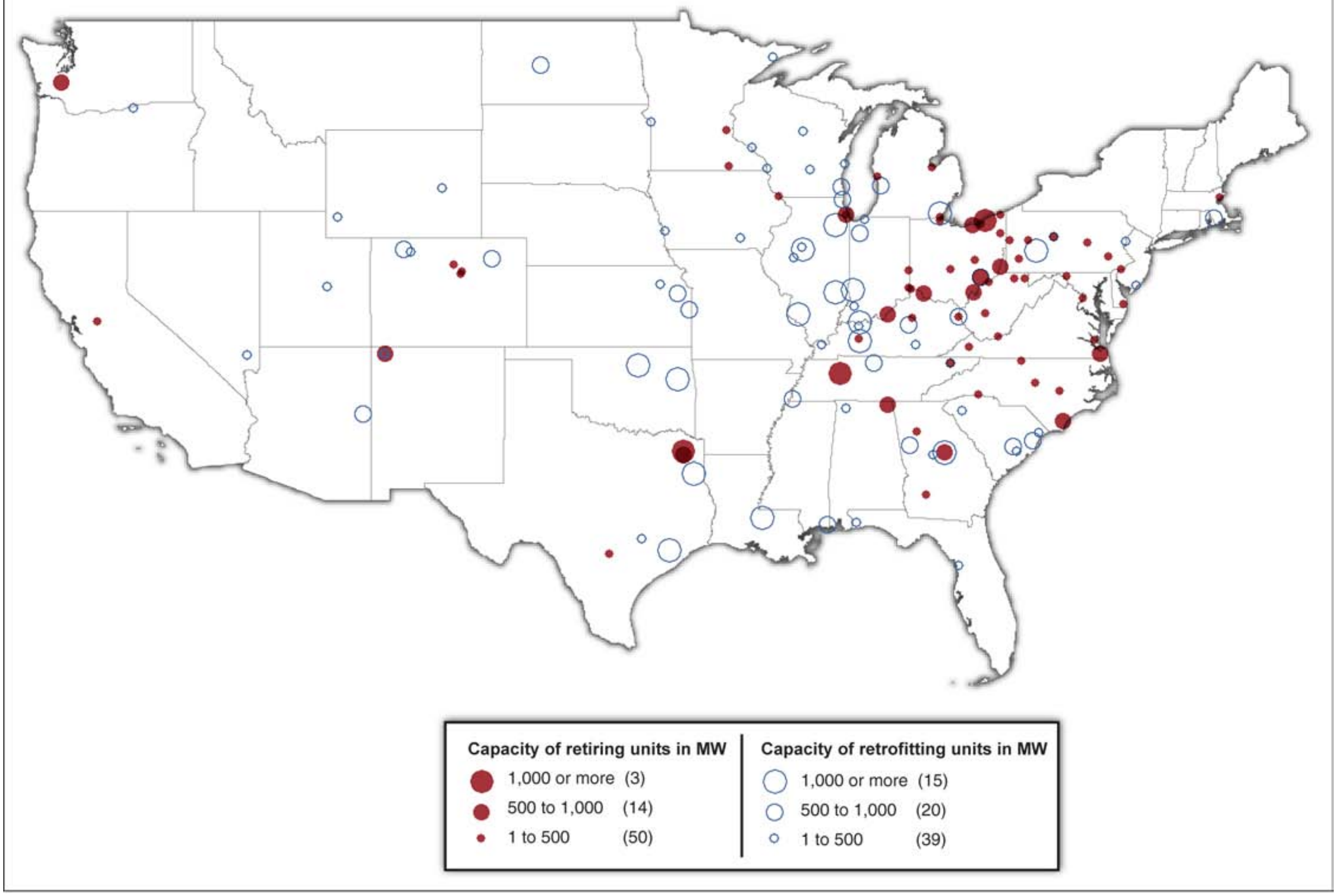
The actions power companies take in response to the four key EPA regulations are not likely to cause widespread reliability challenges, according to the high-level studies we reviewed. Four of the studies we reviewed and an analysis by DOE assessed resource adequacy, one aspect of reliability, by analyzing regional reserve margins—high-level comparisons of projected electricity demand to the projected capacity—after taking into account potential increases in retirements and other changes associated with the EPA regulations. These analyses show how much flexibility there is for power companies to meet peak demand and serve as an important high-level indicator of one aspect of reliability.[70] In general, the studies found that capacity is expected to continue to exceed demand by the amount needed to maintain resource adequacy, in some cases substantially. However, in one study, the reserve margins of Texas and New England are projected to fall below levels needed by 2015 according to some metrics.[71] Narrow reserve margins in Texas and New England are generally expected regardless of actions associated with the EPA regulations and may be attributed to a number of factors such as electricity demand growth exceeding electricity generating capacity. Officials from the system planner in New England told us that they expect to have sufficient capacity available. They noted that at least some of the study results may not have taken into account mechanisms in their region to ensure sufficient capacity is available in the future.

[70]Electricity demand varies significantly with the time of day and year, generally reaching its peak, or highest levels on hot summer afternoons. As demand grows, power companies increase output from the generating units already supplying electricity and begin generating electricity at additional units as needed to meet the rising levels of demand. The last units used to meet rising demand, so-called “peak demand” units, are generally much more expensive to operate and operate the equivalent of only a few days per year. As a result, the costs of generating electricity can vary dramatically, becoming more expensive during periods of peak demand than during periods of average demand.

[71]NERC (2011).

A few more detailed studies that examined local reliability and some stakeholders we interviewed identified the potential for local reliability challenges associated with the four key regulations. Furthermore, representatives from some power companies, RTOs, and other stakeholders told us that the combination of retrofits and retirements in an area could raise system security challenges, for example, if they affect a generating unit needed at a particular location to maintain the electricity system's voltage or to perform other highly technical services to ensure the availability of electricity. Retirements and retrofits could contribute to such concerns if generating units have not been able to retrofit on time or because efforts to mitigate reliability effects are not completed in time. According to EPA documents and some stakeholders we interviewed, there are expected to be few such situations, and existing tools should be sufficient to address issues that do arise. Figure 7 below shows how planned retrofits and retirements through 2020 are distributed nationwide and how these are concentrated in certain areas.

Figure 7: Location and Capacity of Planned Coal-Fueled Generating Unit Retrofits and Retirements through 2020, as of April 9, 2012



Sources: GAO analysis of Ventyx data; Map Resources (map).

Note: Planned retrofits include units with planned SO_2, NO_x, particulate matter, or mercury controls. Includes units with over 25 MW of net summer capacity—the generating unit's capacity to produce electricity during the summer when electricity demand for many electricity systems and losses in efficiency are generally the highest. Net capacity figures exclude output used internally for plant operations.

Specifically, available information and stakeholders identified three potential reliability challenges that could occur at a local level. (For such situations, regulatory or other tools may provide flexibility for resolving challenges. These are discussed in the following section.)

- *Retrofits.* Two aspects of retrofits can cause potential reliability challenges. First, in certain cases, generating units will need to be temporarily shut down to connect new controls, and some stakeholders said that scheduling these shutdowns while maintaining reliability could be challenging in certain areas. According to DOE, shutdowns for the types of controls that may be undertaken in response to MATS and CSAPR usually take less than 8 weeks. In addition, these shutdowns can often be scheduled during regular maintenance periods, and therefore may not require units to be shut down for additional time.[72] More time may be needed for some units, however, because of site specific conditions—such as when a single control device must be connected to multiple generating units—or because installation involves the types of controls that take longer to connect. For example, connecting activated carbon or dry sorbent injection units may require less than a 1-week shutdown. Installing scrubbers, which are more complex, typically requires a 3- to 8-week shutdown, and these installations can sometimes take longer according to information presented by DOE. Scheduling a large number of these longer shutdowns may pose challenges. For example, one system planner told us that companies typically try to schedule such shutdowns during periods of normally low demand, such as the spring and fall, but it may be difficult to schedule all of these longer shutdowns during those periods between now and the compliance date for MATS. Second, if power companies cannot install controls in time to respond to MATS and CSAPR regulations, they may have to shut some units down until such installations are completed, also potentially posing reliability challenges. EPA officials said that large numbers of air pollution controls were installed in response to past regulatory requirements without raising major reliability issues. However, NERC and two of the RTOs we interviewed have expressed concerns about having sufficient generating capacity as companies undertake retrofits that require short-term shutdowns.

- *Retirements.* It is not certain what portion of the 2 to 12 percent of coal-fueled generating units expected to retire could cause reliability challenges that would need to be addressed. Several stakeholders said it could be difficult to resolve all potential reliability challenges

[72]Power companies take generating units off-line for regularly scheduled maintenance that often lasts about 4 weeks.

that may arise because of retirements before the 3-year MATS compliance deadline established by statute. There have been examples in the past of efforts to resolve reliability issues as a result of retirements that have taken multiple years to resolve, and two of the RTOs we spoke with have identified similar challenges going forward. For example, PJM Interconnection (PJM), an RTO system planner in the Mid-Atlantic and Midwest, received 116 requests from power companies to retire units, as of May 30, 2012—representing 16,184 MW of capacity and almost 9 percent of capacity under PJM's authority.[73] PJM has identified reliability concerns with 101 of these retirement requests because they may cause violations of reliability standards. PJM has identified solutions to these potential violations, including transmission upgrades and operational changes, and stated that it expects the resolution of its reliability concerns with 16 of these retirements to take past April 2016—the MATS compliance deadline for units with a 1-year extension.[74] Similarly, as of May 3, 2012, MISO has identified reliability challenges with 8 of the 62 unit retirement notifications it has received and completed evaluations on. MISO expects 5 of these to take until 2018 to resolve.

- *Increasing reliance on natural gas.* Several stakeholders said that increasing dependence on natural gas to produce electricity could pose potential reliability challenges because there could be interruptions in the delivery of natural gas to generating units. In particular, one stakeholder said that there can be other natural gas users on pipelines, such as homeowners in regions of the country where natural gas is used as a home heating fuel, who may also consume natural gas during periods of peak demand. In these areas, constructing pipelines to improve the supply of natural gas to existing or new natural gas-fueled generating units could take time because of a range of financial and regulatory steps that must be taken. Without such upgrades, there may be inadequate natural gas supply in certain locations where it is needed for electricity generation. While pipeline

[73]States served by PJM include all or parts of Delaware, District of Columbia, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

[74]See PJM, "Future Deactivations (as of May 30, 2012)," http://pjm.com/planning/generation-retirements/gr-summaries.aspx. In many cases, it may be possible for these units to retire before 2016 without affecting reliability if, for example, new demand response or substitute generation can be put in place or if operational changes can be used while permanent solutions are developed.

capacity is being expanded in some regions of the country to accommodate rising demand, several stakeholders raised concerns about gas-electric coordination in the industry. To better understand and prepare for these challenges, MISO recently completed a study on the availability of natural gas pipeline infrastructure to support increased use of natural gas-fueled capacity. The study found that some of the region's pipelines that deliver natural gas to power plants may be close to capacity and that further investments in pipeline capacity and additional natural gas storage may be needed to ensure the delivery of reliable natural gas supplies.

Existing Tools Could Mitigate Many Adverse Implications, but Agencies Do Not Have a Formal Process to Monitor Industry Progress Toward Compliance

Various tools available to industry and regulators could help mitigate potential adverse electricity market implications, including some price increases, associated with requirements in the four key regulations. Various tools could also address many, but not all, potential reliability challenges associated with these regulations. In addition, FERC, DOE, and EPA have begun taking steps to monitor industry's progress in responding to the regulations but have not established a formal, documented process for jointly and routinely doing such monitoring, and FERC has not taken steps to proactively assess RTO rules in the context of the EPA regulations.

Available Tools May Help Mitigate Some, but Not All, Price Increases

Various tools available to industry and regulators could help mitigate some, but not all, potential increases in the prices consumers pay for electricity. In traditionally regulated markets, in order to determine whether to allow power companies to recover the costs of responding to the regulations, public utility commissions will hold proceedings to review whether power companies' investments in response to the four key EPA regulations are prudent. These proceedings could involve consideration of whether a power company's compliance strategy—whether to invest in controls, modify a unit to produce electricity using a different fuel source, retire a unit, or build a new unit—is defensible. They could also include a review of the actual costs involved in installing controls. Once approved by the regulator, ratepayers in these markets primarily bear the risk associated with actions to comply with the regulations. State public utility commissions may also review longer-term resource plans developed by power companies to identify when new capacity is needed to accommodate unit retirements and, if appropriate, approve power companies' proposed approaches for obtaining that capacity—building new units, entering into long-term power contracts, or other steps.[75] For example, in 2012, the Georgia Public Service Commission reached a decision in its proceedings to review Georgia Power Company's plans to retire certain generating units and purchase power from other sources to address, among other things, state pollution regulations and MATS. In addition to its other rulings, the Georgia commission approved three of the four power purchase agreements, indicating that such a decision represented the best balance of increased cost to consumers with the benefits of having additional capacity.[76]

In restructured markets, where the prices consumers pay for electricity are influenced by prices set in competitive, organized wholesale markets, the competitive nature of these markets provides an incentive for power companies to ensure that their investment decisions are cost-effective. In these markets, investors in the power company bear the risk associated with these decisions—the installation of any controls that turns out to have been unnecessary or too costly may not yield the additional revenue needed to pay for the investment. In addition, to ensure these markets remain competitive and that prices reflect the cost of producing electricity, FERC officials told us that RTOs and FERC have processes in place to identify, investigate, and prosecute manipulative behavior in wholesale electricity markets, as well as to ensure that prices are set in well-functioning markets representing the interplay of supply and demand. Several stakeholders we spoke with said these processes should be effective at keeping power companies from using actions they may take in response to the EPA regulations as an opportunity to manipulate the electricity markets.

However, these tools in traditionally regulated and restructured markets do not limit power companies from passing on to consumers any legitimate costs they incur in responding to the EPA regulations, such as

[75]There is considerable variation in the tools employed by state public utility commissions to oversee the electricity industry. For example, integrated resource planning, generally a feature of traditionally regulated markets, is not uniformly used in all traditionally regulated states and may also be used in restructured states.

[76]Georgia Power Company also sought approval for initial expenditures related to the installation of fabric filters on some of its units. The Georgia commission approved expenditures associated with the initiation of construction of the fabric filters and required monthly compliance reports on the fabric filter installations until the matter can be reconsidered in Georgia Power's 2013 Integrated Resource Plan.

the costs of installing controls, procuring CSAPR allowances, constructing transmission lines to address reliability challenges, and acquiring power from other sources to compensate for retiring generating units. Two of the state public utility commission representatives we spoke with from traditionally regulated markets said it would be unlikely for a public utility commission to deny cost recovery for prudent investments needed to respond to these EPA regulations. In restructured markets, power companies will attempt to recover the costs they incurred in responding to the regulations through the electricity markets. To the extent that price increases are the result of prudent steps in response to the EPA regulations rather than market manipulation, federal or state regulators may have little authority to mitigate them.

EPA has designed the regulations with some provisions that provide flexibility and allow power companies to minimize the costs of responding to them, which may reduce consumer electricity price increases. For example, by making CSAPR allowances tradable rather than requiring all generating units to individually meet a particular emissions threshold, EPA may enable power companies to achieve overall emissions limits at a lower cost.[77] Additionally, EPA requested public comment on several regulatory provisions in the proposed CCR regulation which, according to EPA officials, could help lower industry compliance costs and reduce price increases.

In addition, some tools could lower demand for electricity, which may offset potential price increases. For example, some states have provided incentives for consumers to purchase more energy efficient household appliances as part of an effort to avoid constructing additional generating units. Furthermore, electricity pricing and other programs can encourage customers to adjust their usage in response to changes in prices or market conditions, which can affect reliability. These programs are collectively referred to as "demand-response" programs, and two types—"market-based pricing" and "reliability-driven"—are in use. Market-based pricing programs enable customers to adjust their use of electricity in response to changing prices. Reliability-driven programs, on the other hand, enable system operators to request that customers reduce

[77]According to EPA's estimates of the proposed CSAPR regulation, allowing allowance trading may lower the costs of achieving emission levels required by CSAPR by over 23 percent compared to a scenario where each generating unit is required to meet its own emissions targets.

electricity use when needed, such as if hot weather or system malfunctions mean that demand will probably exceed supply and cause a blackout. In August 2004, we reported that demand-response programs promote greater efficiency in supplying electricity by postponing the need to construct new generating units and reducing the need to use the generating units that are the most costly to operate. We recommended that FERC consider the presence or absence of demand response when making key decisions about electricity markets, including whether to allow some buyers to participate in wholesale markets.[78] In response to our recommendation, FERC has taken steps to facilitate broader use of demand-response programs among RTOs.

Available Tools Could Address Many, but Not All, Reliability Challenges

Tools available to industry and regulators may also help address many, but not all, potential reliability challenges. For example, planning, market, and operational tools used by system planners and operators to ensure the availability of adequate transmission and generation will help address many potential reliability challenges associated with these regulations. System planners and operators, whether RTOs or individual power companies, manage the electricity system in accordance with NERC reliability standards. With respect to transmission, system planners compare the long-term demand for electricity at various points throughout the system to the location, capacity, and operating limits of generation and transmission resources. These activities require timely information on, among other things, planned retirements and new additions. EPA provided one mechanism through which system planners may receive this information in a more timely way when it instructed power companies seeking Clean Air Act administrative orders—orders to give units up to an additional year to come into compliance with MATS—to provide compliance plans to system planners. In addition, some RTOs have begun requesting that power companies in their regions voluntarily provide early information on their plans to respond to the regulations, including planned retirements, retrofits, and operational changes. With respect to generation, system planner activities vary, with some areas of the country planning their future investment in generation and others using market-based approaches to encourage the development of new generation. System operators take more immediate actions to ensure the

[78]GAO, *Electricity Markets: Consumers Could Benefit from Demand Programs, but Challenges Remain*, GAO-04-844 (Washington D.C.: Aug. 13, 2004).

grid operates in conformance with NERC reliability standards, such as directing when to bring additional generation online to meet demand or improve system operating conditions. System planners and operators must manage changes that power companies make to respond to the EPA regulations—retiring generating units, changing operating schedules, or scheduling shutdowns to install controls—in a way that does not violate NERC's reliability standards. [79] For example, system planners must maintain adequate contingency reserves—such as additional available generation or electricity consumers willing to lower their demand for electricity—to address any unexpected operational problems that arise, even when some electricity generating units retire or are out of service to install controls. Broader initiatives in the electric power industry, such as activities to promote demand-response and energy efficiency, may also help mitigate reliability challenges.

Although these planning, market, and operational tools could address many potential reliability challenges, challenges may still arise if generating units needed for reliability are not in compliance with the EPA regulations by the deadlines. For example, local reliability challenges could occur if generating units that need to operate in a local area to ensure resource adequacy or system security do not meet these regulations' compliance deadlines—either because they have not been able to retrofit on time or because system planners have not yet completed efforts to mitigate the reliability effects of the units' planned retirement. However, according to EPA officials and documentation, most units should be able to complete steps to respond to the regulations prior to their deadlines. Nonetheless, some stakeholders remain concerned and told us that the loss of reliability-critical units that cannot comply by the deadlines could have an adverse impact on reliability.

Six additional tools exist that, according to multiple stakeholders, can be used to address such actual reliability challenges that arise. These tools are: (1) Clean Air Act section 112 1-year extensions, (2) Clean Air Act administrative orders, (3) Clean Air Act consent decrees, (4) reliability-must-run agreements, (5) DOE emergency authority, and (6) Clean Air Act section 112 presidential exemption authority. However, while these

[79] If the actions power companies take in response to the four EPA regulations violate NERC standards, FERC or NERC may take enforcement action, such as requiring a mitigation plan to come into compliance or levying penalties against the power companies, to ensure that reliability is not compromised.

tools are likely to address many reliability challenges arising after the compliance deadlines, as discussed below, there are limitations to using them, which contribute to uncertainty about their collective breadth and applicability as a backstop for addressing all reliability challenges.

- *Clean Air Act section 112 1-year extensions.*[80] This extension of the compliance deadline is a tool through which companies may obtain up to an additional year to comply with MATS if needed for the installation of controls.[81] According to the final MATS regulation's preamble, these extensions should be broadly available to enable power companies to install controls, and permitting authorities—generally states and local authorities— will have the discretion to use this authority to address a range of situations. For example, according to EPA, it may be reasonable for permitting authorities to grant an extension to a unit slated for retirement if its continued operation is needed to maintain reliability while another unit installs emissions controls. An official from one permitting authority we spoke to said, pending executive management approval, its organization plans to adopt EPA's interpretation of when to grant extensions even though this interpretation departs from EPA's and its long-standing interpretation of "installation of controls." However, two stakeholders raised concerns about the certainty of receiving this 1-year extension, with one stakeholder questioning whether permitting authorities would approve extensions for generating units that are retiring rather than installing controls.

- *Clean Air Act administrative orders.*[82] Clean Air Act administrative orders are another tool through which reliability challenges resulting from actions to comply with relevant regulations, for example, MATS, may be addressed. Where necessary to avoid a serious risk to electric reliability, and when certain requirements are met, EPA intends to issue administrative orders to bring a generating unit that is required to run for reliability purposes into compliance with MATS within 1

[80]The extensions are authorized by section 112(i)(3)(B) of the Clean Air Act.

[81]Because the statute limits the extension to 1 year, this tool will not fully address situations in which units need more than 4 years to comply.

[82]These administrative orders are authorized by section 113(a) of the Clean Air Act and, by statute, cannot last for longer than a year or be renewed.

year.[83] According to EPA's MATS enforcement memo, EPA does not intend to seek civil penalties for violations of the MATS regulation that occur as a result of operation in conformance with these administrative orders. Power companies that intend to seek these orders must, among other things, notify system planners by April 16, 2013, of their MATS compliance plans, which EPA expects to help the system planners better manage possible reliability challenges. However, EPA officials told us that such notifications are not required if a power company does not intend to seek additional time to respond, such as if it plans to retire its generating units. Furthermore, some stakeholders have raised concerns that administrative orders do not shield power companies from private parties suing them for violating the MATS regulation.[84] In addition, this tool would not address situations in which units need more than 5 years to comply. EPA officials told us that, if generating units need additional time to respond, EPA will make case-by-case decisions about how to proceed by using, for example, the consent decree process described below.

- *Clean Air Act consent decrees.*[85] Consent decrees are another tool that EPA can use to address situations where a reliability critical unit needs additional time to respond to the regulations. In this context, consent decrees are agreements between the federal government—the Department of Justice, in cooperation with EPA—and power companies that generally establish a schedule for bringing a power company's generating units into compliance with an EPA regulation and typically impose a civil penalty on power companies. According to EPA officials, because these agreements require negotiation and must be filed with a federal court, they can take a year or more to develop. Therefore, a consent decree may only be effective for resolving a reliability challenge if EPA has sufficient advance time to

[83]This policy is described in the EPA MATS enforcement memo, formally titled "The Environmental Protection Agency's Enforcement Response Policy For Use of Clean Air Act Section 113(a) Administrative Orders in Relation To Electric Reliability and the Mercury and Air Toxics Standard" (the "MATS Enforcement Policy"), which is available at http://www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf.

[84]According to EPA officials and two stakeholders, provided that EPA establishes a well-documented record supporting its decision to issue an administrative order, the risk of a successful citizens' suit can be minimized.

[85]These consent decrees are authorized by section 113(b) of the Clean Air Act.

develop it. In addition, according to EPA officials, power companies must be willing to enter into consent decrees. However, in the case of a retiring generating unit, it may be the system planner, rather than the power company, that wants to keep the unit operating. As a result, a power company that wants to retire a reliability-critical generating unit may have little incentive to enter into a consent decree, particularly if it means paying a penalty to do so.

- *Reliability must-run agreements.* Reliability must-run agreements—which provide cost-based payments to the owners of reliability-critical generating units to cover the cost of operating these units past when their owners were planning to retire them—are another possible tool for addressing some reliability challenges. These agreements have been used in the past to address occasional retirements of individual generating units due to changing economic conditions, such as when operating a unit became unprofitable. For example, a reliability must-run agreement was used to keep Hudson Unit 1, a 383 MW unit in New Jersey, operational for reliability reasons for 7 years after the Public Service Enterprise Group, the power company that owns the unit, had requested to retire it. A reliability must-run agreement was needed for so long, in part, because of delays in the construction of a transmission line that was being developed to address potential reliability violations that could occur without the new line.[86] However, these agreements may not be an option for responding to all types of reliability challenges that could arise when power companies seek to retire reliability-critical generating units in response to the four key regulations. According to representatives from some RTOs we spoke to, reliability must-run agreements have historically been used to reimburse power companies for their operating expenses rather than major capital and other expenditures, such as the installation of controls to reduce pollution, or financial penalties for violating environmental laws and regulations. As such, in situations where a power company plans to retire a generating unit, reliability must-run agreements may be useful if an administrative order or consent decree can be obtained. If not, reliability must-run agreements may be less applicable because those units would either have to install controls in order to comply or risk financial penalties for

[86]Specifically, the Susquehanna-Roseland transmission line was being developed to avoid potential reliability violations including some associated with Hudson 1's potential retirement. According to representatives from PJM, permitting issues have significantly delayed the project.

noncompliance.[87]

DOE's Use of Federal Power Act Section 202(c) for the Potomac River Generating Station

In 2005, DOE issued a Federal Power Act section 202(c) order to Mirant Potomac River, LLC to require it to generate electricity at its Potomac River Generating Station, a coal-fueled power plant in Alexandria, Virginia, that primarily supplied power to Washington, D.C. In August 2005, after reviewing emissions modeling, Virginia's environmental regulator determined that the continued operation of the plant at current levels would result in violation of state law and regulations and requested that Mirant "immediately undertake such action as is necessary to ensure protection of human health and the environment." In response, in late August 2005, Mirant reduced operations and then shut the plant down. Mirant resumed limited operations in late September 2005. In late December 2005, DOE used its 202(c) authority to order the plant to generate electricity. In June 2006, EPA issued Mirant a Clean Air Act administrative order, and the DOE order was amended. According to DOE officials, before issuing a 202(c) order, DOE needed time to analyze the unique generation and transmission details of the Washington, D.C. area; understand the plant's operational constraints and environmental requirements; and coordinate with Mirant, EPA, the Virginia Department of Environmental Quality, and others.

In 2007, while operating under DOE's order, problems with the plant's environmental controls led to a violation of state environmental regulations, and state regulators imposed a penalty for failure to (1) operate the plant in a manner consistent with minimizing air emissions and (2) comply with reporting requirements. According to DOE and Virginia officials, the section 202(c) order was designed to allow Mirant to operate without violating state environmental law and regulations. However, former Mirant officials told us that operation at the level specified in the order made a violation unavoidable because they could not lower output in order to reduce emissions.

- *DOE emergency authority.* DOE's authority under section 202(c) of the Federal Power Act to order a power company to generate electricity in certain emergencies is another tool through which reliability challenges resulting from actions to comply with the four regulations may be addressed. For example, DOE could use this authority to require a retiring electricity generating unit that emits more mercury than allowed by MATS to continue to operate after the MATS compliance deadline if the unit was needed to respond to an emergency because of an electric shortage. However, DOE officials told us that they expect to use their section 202(c) authority to address reliability concerns associated with the EPA regulations rarely and as a tool of last resort. Further, in some circumstances, this authority may not provide for timely resolution of potential reliability challenges associated with the four EPA regulations. DOE has used its section 202(c) authority six times in the past, and officials told us that, in most instances, DOE has been able to issue section 202(c) orders quickly.[88] However, DOE officials explained that, in situations where it is less obvious whether there is a reliability emergency, it could take time for officials to analyze whether the requirements for an order are met and issue the order.

  In addition, although DOE may coordinate with EPA and state environmental regulators to ensure the section 202(c) order that is issued does not result in a violation of environmental requirements, some power company representatives expressed concern that operating under a section 202(c) order could still result in a potential conflict between DOE's order and environmental laws and regulations. This could occur if DOE issued a section 202(c) order before agreement could be reached with EPA and state environmental regulators on how to operate the unit to adequately respond to the emergency and comply with applicable environmental

[87]In the case of CSAPR, the cost of allowances purchased by a power company to operate its units could be incorporated into applicable reliability must-run agreements. However, for the reasons described above, an RMR might be less applicable under CSAPR if sufficient allowances were not available for purchase.

[88]Not all of these orders were for the generation of electricity.

laws and regulations.[89] Representatives from two power companies told us that, in these situations, it is unclear whether the power company would (1) refuse to generate electricity and risk electricity reliability or (2) operate in violation of the environmental laws and regulations and risk enforcement action and legal liability. A legal representative at one power company we spoke with explained that he could not advise company officials to operate a unit in violation of the Clean Air Act without additional legal protection. Representatives from another power company said that power companies in such a situation may defer to the courts—a potentially time-intensive solution—to avoid legal liability and determine what course of action they should take. Moreover, power companies may have to negotiate with, or seek approval from, multiple additional parties, including the relevant RTO and FERC, for an agreement outlining the payment terms for the unit's operation under the section 202(c) order, as well as with EPA and state environmental authorities to avoid financial penalties if operation results in violation of environmental laws and regulations. Getting these agreements in order can also be time-consuming which, if the process is not started well in advance, may delay steps to address reliability. EPA staff commented that the agency will be closely tracking cases where extensions and orders are used.

- *Clean Air Act section 112 presidential exemption authority.* The broad authority provided to the President to exempt power companies from complying with MATS is a potential tool to avoid reliability challenges, but this authority has never been used, and uncertainties exist as to how this tool would apply to reliability challenges that arise under MATS. Section 112(i)(4) of the Clean Air Act authorizes the President to exempt any generating unit from compliance with MATS for a period of not more than 2 years under certain circumstances.[90]

[89] Furthermore, a power company operating under a section 202(c) order may have limited options when addressing certain circumstances at a power plant that could result in violations of environmental laws or regulations. For example, if a generating unit's environmental controls malfunction or fail unexpectedly, a power company operating under a section 202(c) order may not be able to take action, such as reducing operation, to avoid violating federal or state environmental laws or regulations. If a violation occurs, the power company may be subject to enforcement action or lawsuits brought by private parties.

[90] An exemption under this subsection may be extended for one or more additional periods, each period not to exceed 2 years. The President must report to Congress on each exemption or extension of an exemption made.

Specifically, the President must make two determinations to use this authority: (1) that the technology to implement the regulation is not available and (2) that the exemption is in the national security interests of the United States. As of May 2012, this authority has never been used, and there is uncertainty about whether these conditions could be met. For example, as to the first determination, EPA established emissions standards for mercury and other pollutants that can be met with technology that has been available for a significant time. However, according to EPA staff, EPA's rulemaking was not intended to and did not consider the interpretation of the term 'available' as used in the presidential exemption provision. Furthermore, regarding the second determination, EPA staff explained that the record supporting EPA's rulemaking includes some information that others might consider relevant in making any such determination. EPA officials also noted, however, that section 112(i)(4) authorizes the President, not EPA, to act. Regarding these determinations, according to one stakeholder, it would be implausible to claim that technology to comply with MATS is not available, and there is not currently evidence of a sufficient threat to national security. Another stakeholder, however, has argued that the statute is sufficiently broad to allow the exemption authority to be used in some situations when a power company does not have the physical ability to obtain, purchase, and install technology by the deadlines and that the true extent of reliability challenges' threat to national security interests cannot be fully known until specific reliability studies are completed based on specific compliance plan proposals. Several stakeholders we spoke to during this review indicated that the presidential exemption authority can be used, though two said the statute establishes a high threshold that must be met.

In addition to these six tools, some provisions in two of the regulations—CSAPR and 316(b)—help address electric reliability. For example, CSAPR allows power companies to run existing controls more often, install additional controls, or acquire allowances by purchasing them from another source or using allowances saved from prior years. According to EPA officials, this flexibility can help power companies plan and manage their operations in a manner that ensures system reliability. With respect to 316(b), as indicated in the preamble to the proposed regulation, permitting authorities have flexibility to tailor compliance timelines to enable installation without negatively impacting the reliability of electric supply.

Agencies Have Begun Taking Steps to Monitor Industry's Progress but Have Not Documented Their Process, and FERC Has Not Proactively Reviewed RTO Rules

FERC, DOE, and EPA have begun taking steps to monitor industry's progress in responding to the regulations but have not established a formal, documented process for joint and routine monitoring, and FERC has not taken steps to proactively assess RTO rules in the context of the regulations. FERC, DOE, and EPA officials said they have taken initial steps to understand the status of industry's plans to respond to the regulations, and officials from each agency told us they have periodically met with affected stakeholders—for example, power companies, state public utility commissions, and all of the RTOs, among others—to discuss the regulations' impact and the status of industry compliance. For example, staff from all three entities said they have had multiple conference calls with RTOs in areas affected by the regulations. In addition, FERC hosted a technical conference in 2011 to discuss policy issues related to the EPA regulations with industry stakeholders,[91] and FERC and state public utility regulators have established a forum to explore reliability challenges related to the EPA regulations.[92] Furthermore, according to EPA staff, the agency had multiple meetings with all of the major utility trade associations, as well as a number of large power companies with substantial coal-fueled generating capacity, to discuss compliance plans and issues that are emerging. However, each agency's efforts are varied in scale and scope, and none of the agencies has developed a formal, documented process for routinely monitoring industry progress, including goals for any monitoring activities, data to be collected and analyzed, and how the agencies will use this information. Officials from FERC and DOE told us they had not formalized their processes for monitoring industry's progress since power companies were in the process of finalizing their approach for responding to the regulations.

As discussed, actions power companies take in response to the four regulations may present potential reliability challenges, or risks. In a December 2005 report on risk management, we reported that monitoring

[91]See FERC, "Technical Conference to Discuss Policy Issues Related to Reliability of the Bulk Power System," AD12-1-000, (Washington, D.C.: Nov. 29-30, 2011) http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=6053&CalType=%20&CalendarID=116&Date=&View=Listview.

[92]Specifically, FERC and the National Association of Regulatory Utility Commissioners, a national organization representing State public service commissioners, established a forum on reliability and the environment that first met on February 7, 2012. The next meeting is scheduled for July 25, 2012.

is essential in ensuring that a risk management approach is current and relevant.[93] Without a formal, documented process that the three agencies have agreed on for monitoring industry's progress toward meeting the compliance deadlines, it is uncertain how comprehensive the agencies' monitoring efforts will be and whether they will adequately address such specific issues as the status of required regulatory approvals, the availability of key materials and skilled workers, the likelihood of potential reliability challenges, and the adequacy of existing tools for addressing these challenges.[94] Without a formal, documented process for monitoring, it is also uncertain whether the agencies' future monitoring activities will be sufficiently comprehensive to alert them in advance if a larger than expected number of reliability challenges arise so they can assess whether internal agency resources are available to carry out their responsibilities. For example, if there is a larger than expected number of local reliability challenges, FERC may be less able to effectively and quickly manage reviewing (1) applications for cost recovery for transmission investments, (2) the reliability impacts of electricity generating units whose owners seek an administrative order from EPA for compliance with MATS, (3) reliability must-run agreements outlining the payment terms for the operation of a unit that would otherwise retire, and (4) whether steps should be taken to require RTOs or market participants to secure additional demand-response resources.[95]

Furthermore, these three agencies have informally collaborated about the EPA regulations, but they have not developed a formal, documented process for coordinating their monitoring efforts. Officials from all three responsible agencies said they have held periodic discussions with officials from the other agencies. This informal collaboration also involved

[93]GAO, *Risk Management: Further Refinements Needed to Assess Risks and Prioritize Protective Measures at Ports and Other Critical Infrastructure*, GAO-06-91 (Washington, D.C.: Dec. 15, 2005). Risk management is a strategy for helping policymakers make decisions about assessing risks, allocating resources, and taking actions under conditions of uncertainty.

[94]Some system planners—including power companies and RTOs—and state regulators have begun collecting information that may relate to these topics.

[95]FERC officials said they believe they will have adequate staff to address most of these responsibilities. However, they agreed that a larger than expected number of local reliability challenges could make it difficult for them to review the reliability impacts of units whose owners request an administrative order from EPA. FERC recently issued a policy statement explaining the process it intends to use to provide timely advice to EPA on requests for administrative orders.

participation in the FERC technical conference on the EPA regulations and joint agency participation at meetings with industry stakeholders. EPA officials told us the agencies have agreed to work together to monitor the progress of industry's compliance with the regulations in the future. However, these agencies have not documented their process for coordination, including the expected frequency of contact with each other and industry, key agency responsibilities, and how they will share information. We have previously reported that by using informal coordination mechanisms, agencies may rely on relationships with individual officials, which could end once personnel move to their next assignments.[96] We reported that agencies can strengthen their commitment to work collaboratively by articulating their roles and responsibilities in formal documents—such as memorandums of understanding or interagency planning documents—to facilitate decision making. These documents can clarify which agencies will be responsible for particular activities and how they will organize their individual and joint efforts. Without more formal coordination mechanisms, any assessment of whether tools are sufficient to mitigate potential reliability challenges may not fully leverage the perspective of all three agencies, each of which has a unique area of expertise and ability to perform different analysis. Each of the three agencies may have knowledge of whether particular tools are useful for addressing actual reliability challenges, and DOE and FERC may be able to provide insight into the magnitude and urgency of such challenges.

Moreover, according to agency officials, the agencies do not have a formal, documented process for how they will provide information from their monitoring efforts to Congress. Without information on whether existing tools are sufficiently timely, relevant, and effective for addressing any adverse implications that arise, Congress may not be sufficiently informed about whether additional statutory authority is needed. Through multiple hearings and an information request to FERC, members of Congress have already sought additional information on these issues. Legislation has also been introduced to, among other things, extend the

[96] GAO, *Live Animal Imports: Agencies Need Better Collaboration to Reduce the Risk of Animal-Related Diseases*, GAO-11-9 (Washington, D.C.: Nov. 8, 2010); GAO, *National Security: Key Challenges and Solutions to Strengthen Interagency Collaboration*, GAO-10-822T (Washington, D.C.: June 9, 2010); GAO, *Homeland Defense: U.S. Northern Command Has Made Progress but Needs to Address Force Allocation, Readiness Tracking Gaps, and Other Issues,* GAO-08-251 (Washington, D.C.: Apr. 16, 2008).

compliance dates for MATS and CSAPR, to prohibit or invalidate one or more of the regulations, and establish that compliance with a section 202(c) order cannot be considered a violation of any environmental law or regulation. Without information such as what could be provided through EPA, FERC, and DOE's joint monitoring efforts, Congress will be less informed when it deliberates these bills about the extent to which actual reliability concerns arise and whether new statutes are needed to address them.

Furthermore, FERC has not taken steps to proactively assess whether RTO market rules and similar rules at non-RTO system planners will be adequate to ensure timely, cost-effective mitigation of the potential reliability challenges associated with the multiple generating unit retirements and outages that may occur over a short period due to the EPA regulations and other factors. These rules govern such things as how these entities schedule temporary shutdowns for retrofits, receive notifications from power companies regarding retirements of generating units, and address potential reliability challenges, including how transmission upgrades and demand response are considered and pursued. These rules affect how cost-effectively reliability challenges are managed. Table 3 shows examples of RTOs that have begun reviewing their rules related to electricity transmission, markets, and other areas and are considering whether changes are needed in light of the EPA regulations and other industry factors. Changes under consideration relate to scheduling outages, unit retirements, and planning for transmission needs. Many are being considered with the goal of avoiding unnecessary costs or reliability problems. For example, under current market rules in the MISO region, power company retirement requests are binding, meaning once a power company has submitted a request to retire, it cannot change its mind. MISO stakeholders are discussing whether changes need to be made to market rules to allow power companies to submit nonbinding requests for unit retirements, so that MISO can provide these companies with information on the reliability impacts of their proposed retirements prior to these companies making a final decision about whether to retire. According to MISO officials, if a power company received this information prior to making a retirement decision, the company might be able to make more cost-effective choices by comparing the cost of steps to address reliability concerns associated with a potential retirement to the cost of complying with the regulations by installing environmental controls.

Table 3: Selected Concerns about RTO Market Rules Arising from the EPA Regulations and Other Industry Factors

Region	Concern about RTO market rule	Potential change and status
ERCOT[a]	The Electric Reliability Council of Texas (ERCOT) manages the transmission of electricity for most of Texas and does not always have authority to deny outages that may adversely impact reliability.	Modify outage rules so ERCOT can deny outages that pose reliability challenges. (Concern identified)
MISO	Power companies in the MISO region may not have full information about the reliability and cost implications of retiring a particular generating unit. According to MISO officials, if a power company received this information prior to making a retirement decision, the company might be able to make more cost-effective choices. For example, if a power company learned that the cost of actions to offset the retirement of a reliability-critical generating unit were more expensive than installing pollution controls, it might choose to install controls rather than retire the unit.	Allow power companies to submit nonbinding requests for unit retirements, so that MISO can provide these companies with information on the reliability impacts of their proposed retirements. (Under discussion)
MISO	Because they have comparatively shorter start-up times than coal plants, certain natural gas plants have historically provided “quick start” capacity for addressing short-term capacity shortages. However, because the EPA regulations increase the costs of using coal relative to natural gas for electricity production, and because of recent lower natural gas prices, natural gas plants previously used as quick start capacity may be used more routinely, which could limit their availability to provide quick start capacity.	Modify market rules to encourage the development of additional “quick-start” capacity. (Under discussion)
MISO	Power companies are required to notify MISO 26 weeks before retiring generating units. Because some options to address potential reliability challenges can take several years, such as building a large transmission line, not having timely information about all planned retirements could limit the options available to MISO and increase the costs of mitigating these challenges. However, earlier notification than 26 weeks may not be practical since power companies may not know their plans that far in advance.	Keep MISO’s notification time frame at 26 weeks, but make other modifications to MISO’s process for receiving and evaluating notifications of pending retirements, including allowing for nonbinding retirement requests. (Under discussion)
ISO New England	In ISO New England, the transmission planning process and resource adequacy markets are not as well-aligned as possible. As a result, concerns about resource adequacy and local reliability may be addressed less efficiently and with higher costs.	Take steps to better align resource adequacy markets with the transmission planning processes. This proposed change was prompted by multiple events, including environmental compliance costs associated with EPA regulations and the economics of fuel prices. According to an ISO New England document, the RTO expects these proposed changes to better address reliability needs and mitigate cost increases. (Under discussion)
PJM	PJM’s transmission planning process did not include an analysis of “at-risk” generation or possible future scenarios that are as extensive as the RTO would like.	Revise PJM’s transmission planning process to allow it to better manage uncertainty about “at-risk” generation due to changes in environmental regulations, among other things. The change included clarifying that PJM can consider proposed public policy initiatives in its planning analyses. (Conditionally accepted by FERC)

Sources: GAO analysis of RTO documents, discussions with RTO officials, and other sources.

[a]The Public Utility Commission of Texas, rather than FERC, regulates the design and operation of the electricity markets in the ERCOT region.

FERC officials told us that initial discussions with the RTOs—such as through the FERC technical conference—indicated that current market rules are adequate and that FERC will review any proposed changes to market rules that they receive from RTOs to ensure that the rules continue to promote just and reasonable rates and, where relevant, address reliability issues. However, the commission does not have plans to proactively assess the adequacy of any rules unless RTOs propose specific changes. Furthermore, FERC officials said the commission does not plan to evaluate whether changes proposed by one RTO may also be useful at others. FERC officials said they have also not assessed the rules of non-RTO system planners because FERC has more limited authority over non-RTO rules. However, FERC officials acknowledged that they have the authority to proactively request that RTOs make changes to rules if FERC believes a rule change is warranted. Under the current approach—wherein individual RTOs consider potential changes and request approval from FERC—FERC risks taking a piecemeal approach to oversight and may miss opportunities to encourage development of market rules in all regions that are adequately designed to promote just and reasonable rates in the context of the industry's transition.

Conclusions

The four key EPA regulations—two finalized and two proposed—would reduce adverse health or environmental impacts associated with coal-fueled electricity generating units, potentially avoiding thousands of premature deaths each year. Aspects of these regulations remain uncertain, but they, along with other industry trends such as the aging of coal-fueled generating units and lower prices for natural gas, are expected to contribute to significant changes in electricity systems in some parts of the United States in the near future. These potential changes, which include retrofitting many coal-fueled units and retiring more coal-fueled capacity than has been retired over the past 22 years, have implications for electricity prices and reliability. FERC, DOE, and EPA each have key responsibilities concerning the electricity industry and all three agencies have taken steps to address potential adverse implications associated with these regulations.

Existing tools provide a foundation for mitigating many of the price and reliability implications of actions power companies may take in response to the regulations. However, these tools may not fully address all potential adverse implications in some regions, for example, some reliability challenges that arise after the compliance deadlines. Knowledge of the severity and extent to which challenges arise will be key to understanding whether existing tools are adequate or additional tools are needed. FERC, DOE, and EPA have taken important first steps to coordinate with RTOs, other system planners, and state regulators, among others, to better understand these issues. However, without a formal, documented process that the three agencies have agreed upon for jointly, routinely monitoring industry's progress, it is uncertain whether their activities will be sufficiently comprehensive and fully leverage their unique areas of expertise. FERC, DOE, and EPA can build on their initial monitoring efforts by documenting their process for monitoring, including the expected frequency of their contact, and how they will organize their efforts and share information. Moreover, as shown by multiple hearings and the introduction of legislation that would affect some or all of the regulations, there has been congressional interest in the potential reliability and price implications of these regulations. Information from a coordinated monitoring effort could help inform these ongoing deliberations and make clear whether additional statutory authority is needed to cost-effectively address any reliability challenges that actually arise.

In addition, rules at system planners, including RTO market rules and, in some cases, similar rules at non-RTO system planners, govern such details as how these entities schedule temporary shutdowns for retrofits; receive notification from power companies regarding retirements of generating units; and address potential reliability challenges, including how transmission upgrades and demand-response are considered and pursued. These rules matter greatly in terms of whether potential reliability challenges are managed as cost-effectively as possible. FERC has not proactively evaluated whether RTO rules will be adequate to ensure timely, cost-effective mitigation of potential reliability challenges associated with multiple generating unit retirements and shutdowns, which may occur over a short period in light of the EPA regulations. As a result, FERC may miss opportunities to encourage development of rules in all regions that are adequately designed to promote just and reasonable rates in the context of the industry's transition.

Recommendations for Executive Action

We are making the following two recommendations:

- To further strengthen agency efforts to understand whether existing tools are adequate, or additional tools are needed, we recommend that the Chairman of FERC, the Secretary of Energy, and the Administrator of the EPA develop and document a formal, joint process consistent with each agencies' respective statutory authorities to monitor industry's progress in responding to the EPA regulations until at least 2017. Each agency, to the extent practical, should leverage resources and share the results of its efforts with the other agencies. The agencies should consider providing Congress with the results of their monitoring efforts, including whether additional statutory authority is needed to address any potential adverse implications.

- To ensure that RTO market rules and, to the extent practical, similar rules at non-RTO system planners promote timely, cost-effective mitigation of potential reliability challenges associated with the EPA regulations reviewed in this report, we recommend that the Chairman of FERC assess the adequacy of existing rules for this purpose. In particular, this assessment should cover rules related to scheduling retrofits, retirement notification, and whether more can be done to facilitate demand response. If the FERC Chairman determines that these rules are not adequate, FERC should consider requesting that these entities make changes where appropriate.

Agency Comments and Our Evaluation

We provided a draft of this report to FERC, DOE, and EPA for comment. In written comments, which are reproduced in appendixes V through VII, DOE and EPA agreed with the recommendation directed to them, and FERC disagreed with both recommendations directed to it.

Regarding our first recommendation that FERC, DOE, and EPA develop and document a formal process to monitor industry's progress in responding to the EPA regulations, DOE and EPA generally agreed. FERC disagreed with the recommendation, stating that we did not take into account a number of actions FERC has taken, including publicly committing to work closely with industry, states, and other agencies to address issues that arise. FERC cited several examples of the actions it has taken, and we made some clarifying changes and, in one case, added language about an example that we had not previously included in the report. FERC also stated that it had taken further steps to implement our recommendation after seeing our draft report. We agree that FERC has taken positive steps, and we are encouraged that FERC has begun to implement our recommendations. However, we do not believe these actions adequately represent the type of formal, documented process needed for EPA, DOE, and FERC to monitor industry's progress in responding to the regulations. FERC also said that, as an independent agency, it cannot dictate the sharing of information with and by other parts of the government. We acknowledge there may be limits on the extent to which the three agencies can collaborate and clarified our recommendation accordingly. All three agencies noted that they are working to establish a more formalized approach to continued coordination, outreach, and monitoring. We commend the agencies for their efforts and believe it is important for them to complete these efforts in order to establish a more formalized approach.

Regarding our second recommendation that FERC assess the adequacy of existing RTO market rules, and similar rules at non-RTO system planners, FERC stated that it continually assesses the rules of entities over which it has jurisdiction and that it has specifically explored whether changes are needed to respond to the regulations. In particular, FERC noted that it asked participants at a 2011 technical conference to address whether changes were needed in market rules and that the response from panelists and commenters was that no significant changes were needed. Our observation from attending this conference is that it fostered a useful exchange of ideas and perspectives. However, we do not believe it is a substitute for an assessment by FERC of the adequacy of rules. FERC also noted that several recent rulemakings may lead to changes in rules that may be beneficial in the context of the EPA regulations, such as in how information is gathered regarding retirements and how demand response is encouraged. These are also positive steps, but they do not constitute an assessment of whether RTO market rules need to be modified to ensure timely, cost-effective mitigation of potential reliability challenges that may be associated with responses to the regulations.

In addition, FERC, DOE, and EPA provided technical comments and clarifications, which we incorporated as appropriate.

As agreed with your office, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies to the appropriate congressional committees, the Secretary of Energy, Chairman of FERC, Administrator of the EPA, and other interested parties. In addition, the report will be available at no charge on the GAO website at http://www.gao.gov.

If you or your staff members have any questions about this report, please contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov or David Trimble at (202) 512-3841 or trimbled@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff who made key contributions to this report are listed in appendix VIII.

Sincerely yours,

Frank Rusco

Frank Rusco
Director, Natural Resources and Environment

David C. Trimble

David C. Trimble
Director, Natural Resources and Environment

Appendix I: Scope and Methodology

This report provides information on the implications associated with four key recently proposed or finalized regulations from the Environmental Protection Agency (EPA): (1) the Cross-State Air Pollution Rule (CSAPR); (2) the Mercury and Air Toxics Standards (MATS); (3) the proposed Cooling Water Intake Structures at Existing and Phase I Facilities regulation, also known as 316(b), and (4) the proposed Disposal of Coal Combustion Residuals from Electric Utilities regulation (CCR). Specifically, this report addresses: (1) what available information indicates about actions power companies may take at coal-fueled generating units in response to the four key EPA regulations; (2) what available information indicates about these regulations' potential implications on the electricity market and reliability; and (3) the extent to which EPA, FERC, DOE, and other stakeholders can mitigate adverse electricity market and reliability implications, if any, associated with requirements in these regulations.

To provide available information on actions power companies may take in response to these regulations and their potential market and reliability implications, we (1) selected for review 12 studies of companies' projected responses to the regulations, as well as the potential impacts of these responses, and (2) analyzed data from Ventyx Velocity Suite on electricity generating units. We considered several factors in selecting these studies including how closely they reflected the four regulations, and we prioritized studies published after significant changes in the regulations, and those from independent groups or federal agencies. We also selected certain studies that provided information on specific aspects of our review, such as those with estimates of price implications and that contained regional assessments. The studies we selected were carried out by EPA, the Energy Information Administration, system planners, research organizations, and a consulting firm. (Selected studies are listed in app. III.) We took several steps to evaluate the reasonableness of the studies' assumptions and methodologies, including reviewing descriptions of the policy scenarios that formed the basis of the studies' analysis. In some cases, we identified differences between study assumptions and the regulations themselves, which we note in the text where appropriate. Some of these studies analyze several scenarios, and we report results from those scenarios which we felt best reflect the regulations. The actual price and reliability implications of these four regulations will depend on various uncertain factors, such as future market conditions and the ultimate regulatory requirements, but we determined that these studies were reasonable for describing what is known about the range of potential actions power companies may take and implications of the four regulations.

We also analyzed data from Ventyx Velocity Suite EV Market-Ops database to describe characteristics of coal-fueled generating units and to provide information on historic and planned retrofits and retirements of such units. We reviewed this data as of April 9, 2012, from all operating units that had capacity greater than 25 megawatts, making them subject to MATS and CSAPR. In all, we examined the characteristics of 1,050 coal-fueled electricity generating units, accounting for 99 percent of all coal-fueled capacity and 75 percent of coal-fueled units. We classified detailed air pollution controls into control types, and reviewed our classifications with officials at Ventyx, the Department of Energy (DOE), and EPA. Information regarding planned retrofits and retirements reflect publicly reported plans as identified by Ventyx. As plans may change, actual future retrofits and retirements may differ from the data in these plans. To assess the reliability of the Ventyx data, we reviewed existing documentation about the data and the system that produced them, interviewed Ventyx staff who were knowledgeable about the data, consulted with EPA and DOE officials and other knowledgeable parties, conducted some electronic testing, and compared data in Ventyx to information obtained from several power companies and regional transmission organizations. We determined the Ventyx data to be sufficiently reliable for the purpose of this report.

To examine the extent to which industry, regulators, and other stakeholders can mitigate adverse implications, we interviewed officials at the Federal Energy Regulatory Commission (FERC), DOE, North American Electric Reliability Corporation, and EPA to better understand what steps they had taken to mitigate potential reliability and price challenges and additional options for doing so. We reviewed relevant laws, regulations, and agency documentation for information on agency authorities, responsibilities with respect to the EPA regulations, and options for mitigating adverse reliability concerns. We conducted multiple interviews with system planners and operators in both restructured and traditionally regulated markets that are expected to be significantly affected by the regulations to understand the tools they had available for managing electric reliability and prices.

To address all three objectives, we summarized the results of semistructured interviews with a nonprobability sample of 33 stakeholders. (See app. II for a list of these stakeholders.) We selected these stakeholders to be broadly representative of differing perspectives on these issues based on recommendations, including from FERC, DOE, and industry associations, and other factors. In particular, we obtained views and information from staff at power companies that may be affected by these regulations, regional transmission organizations, and officials in six states—Georgia, Kentucky, Missouri, Ohio, Pennsylvania, and Texas—to understand the role of these state agencies in addressing the reliability and price implications of the regulations. To select states and companies, we considered, among other factors, the amount of state and companies' electricity generating capacity that is coal-fueled. We also sought a balance of states and companies in and out of RTO regions that were traditionally regulated and restructured. We provided a preliminary list of the stakeholders we intended to interview to FERC and EPA, and we incorporated their suggestions in considering stakeholders where appropriate. Because we used a nonprobability sample, the views of these stakeholders are not generalizable to all potential stakeholders, but they provide illustrative examples.

We conducted this performance audit from July 2011 to July 2012 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Appendix II: List of Stakeholders

Federal Agencies

1. Department of Energy
2. Environmental Protection Agency
3. Federal Energy Regulatory Commission

State Electricity and Environmental Regulators[1]

4. Georgia
5. Kentucky
6. Missouri
7. Ohio
8. Pennsylvania
9. Texas

Regional Transmission Organizations

10. Electric Reliability Council of Texas
11. ISO New England
12. Midwest Independent Transmission System Operator
13. New York Independent System Operator
14. PJM Interconnection
15. Southwest Power Pool

Power Companies

16. American Electric Power
17. Big Rivers Electric Corporation
18. Calpine

[1]With the exception of Kentucky, Missouri, and Pennsylvania, we spoke with both electricity and environmental regulators in these states.

19. City Utilities of Springfield
20. Exelon Corporation
21. First Energy
22. GenOn Energy
23. Southern Company
24. Tennessee Valley Authority

Other

25. Alstom
26. Bernstein Research
27. Clean Air Task Force
28. FBR Capital Markets
29. International Brotherhood of Electrical Workers
30. North American Electric Reliability Corporation
31. Potomac Economics
32. Prof. Henry Jacoby, Massachusetts Institute of Technology Sloan School of Management
33. Susan Tierney, The Analysis Group

Appendix III: List of Studies

Burtraw, Dallas, Karen Palmer, Anthony Paul, and Matt Woerman (RFF). “Secular Trends, Environmental Regulations, and Electricity Markets.” *Resources for the Future Discussion Paper*. DP12-15. Washington, D.C.: March 2012.

Energy Information Administration (EIA). *Annual Energy Outlook 2012 Early Release Overview*. DOE/EIA-0383ER. Washington, D.C.: January 23, 2012.

Environmental Protection Agency (EPA-316b). *Economic and Benefits Analysis for Proposed Section 316(b) Existing Facilities Rule*. EPA 821-R-11-003. March 28, 2011.

Environmental Protection Agency (EPA-CCR). *Regulatory Impact Analysis For EPA’s Proposed RCRA Regulation Of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry*. Washington, D.C.: April 30, 2010.

Environmental Protection Agency (EPA-CSAPR). *Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 states*; Correction of SIP Approvals for 22 States. June 2011.

Environmental Protection Agency (EPA-MATS). *Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards.* EPA-452/R-11-011. Research Triangle Park, NC: December 2011.

IHS Global Insight. *US Energy Outlook*. September 2011.

Macedonia, Jennifer, Joe Kruger, Lourdes Long, and Meghan McGuinness (Bipartisan Policy Center). *Environmental Regulation and Electric System Reliability*. Washington, D.C.: Bipartisan Policy Center, June 13, 2011.

Midwest Independent Transmission System Operator. (MISO). *EPA Impact Analysis: Impacts from the EPA Regulations on MISO*. October 2011.

NERA Economic Consulting (NERA). *Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations.* Prepared for the American Coalition for Clean Coal Electricity. Boston, MA: September 2011.

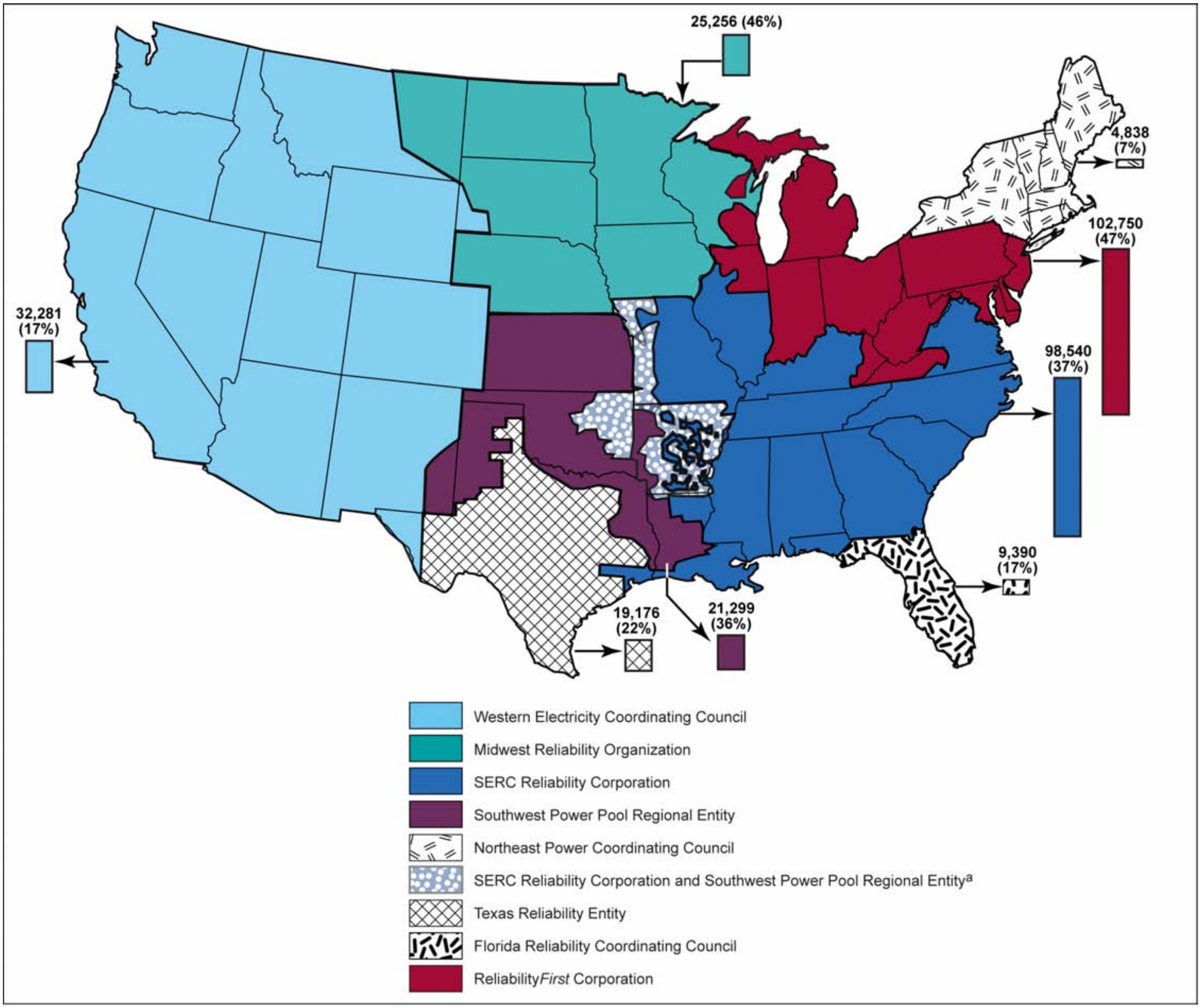
North American Electric Reliability Corporation (NERC). *2011 Long-Term Reliability Assessment.* November 2011.

PJM Interconnection (PJM). *Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants*. August 26, 2011.

Appendix IV: Additional Information on Coal-Fueled Electricity Generating Units

Figure 8 shows the distribution of the nation's coal-fueled electricity generating units by the territories of eight regional reliability entities that set and enforce reliability standards for the electricity industry.

Figure 8: Capacity and Share of Total Capacity from Coal-Fueled Electricity Generating Units by Region, as of April 9, 2012



Sources: GAO analysis of Ventyx data, North American Electric Reliability Corporation, and Map Resources (map).

Note: Capacity is in megawatts and includes units with over 25 megawatts of net summer capacity—the generating unit's capacity to produce electricity during the summer when electricity demand for many electricity systems and losses in efficiency are generally the highest. Net capacity figures exclude output used internally for plant operations.

[a]The combined area of SERC Reliability Corporation and Southwest Power Pool Regional Entity refers to overlapping regional area boundaries. For example, some generating unit owners participate in one region and their associated transmission system owner in another. Generating unit capacity is accounted for in the region where the generation owner participates.

Various air pollution controls are used at electricity generating units to reduce emissions of air pollutants by either reducing the formation of these emissions or capturing them after they are formed. At coal power plants, these controls are generally installed in either the boiler, where coal is burned, or the ductwork that connects a boiler to the stack. A single power plant can use multiple boilers to generate electricity, and the emissions from multiple boilers can sometimes be connected to a single stack. The reduction in emissions from a coal-fueled generating unit by the use of pollution controls can be substantial, as shown in table 4. Controls may be capable of removing multiple pollutants. For example, a wet scrubber can control both sulfur dioxide (SO_2) and acid gas emissions.

Table 4: Summary of Air Pollution Control Equipment Used at Coal-Fueled Electricity Generating Units

Primary pollutant targeted	Equipment name	How it works	Removal efficiency
Particulate matter[a]	Electrostatic precipitator	An induced electrical charge removes particles from flue gas.	99.5%
	Fabric filter (commonly referred to as a "baghouse")	Flue gas passes through tightly woven fabric filter "bags" that filter out the particulates.	99.9%
SO_2 and other acid gases[b]	Flue gas desulfurization unit (commonly referred to as a "scrubber")	Wet flue gas desulfurization units inject a liquid sorbent, such as limestone, into the flue gas to form a wet solid that can be disposed of or sold. Dry flue gas desulfurization units inject a dry sorbent, such as lime, into the flue gas to form a solid byproduct that is collected.	Wet scrubbers – 99% removal of SO_2 Dry scrubbers – 95% removal of SO_2
	Dry sorbent injection unit	An alkaline powdered material is injected into the flue gas (postcombustion) to react with the SO_2 and other acid gases. The resulting product is then collected through a particulate matter control device.	50% with an electrostatic precipitator, 75% with a fabric filter
Nitrogen oxides (NO_x)	Combustion control technologies, such as low-NO_x burners[c]	Coal combustion conditions are adjusted so less NO_x is formed.	45% reduction in the formation of NO_x
	Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) units	SCRs inject ammonia into flue gas to form nitrogen and water and use a catalyst to enhance the reaction. SNCRs inject ammonia into flue gas to react with NO_x as well but do not use a catalyst.	SCRs – 95% removal of NO_x SNCRs –75% removal of NO_x
Mercury[d]	Activated carbon injection units	Activated carbon is injected into flue gas, binds with mercury, and is collected in a particulate matter control device.	At least 90% with a fabric filter

Sources: GAO summary of reports by EPA, EIA, National Academies, Electric Power Research Institute, and industry documents.

Note: Removal efficiency figures refer to the highest capacity to remove listed pollutants. Units may not always achieve these removal rates.

[a]The MATS regulation specifically places limits on "filterable" particulate matter.

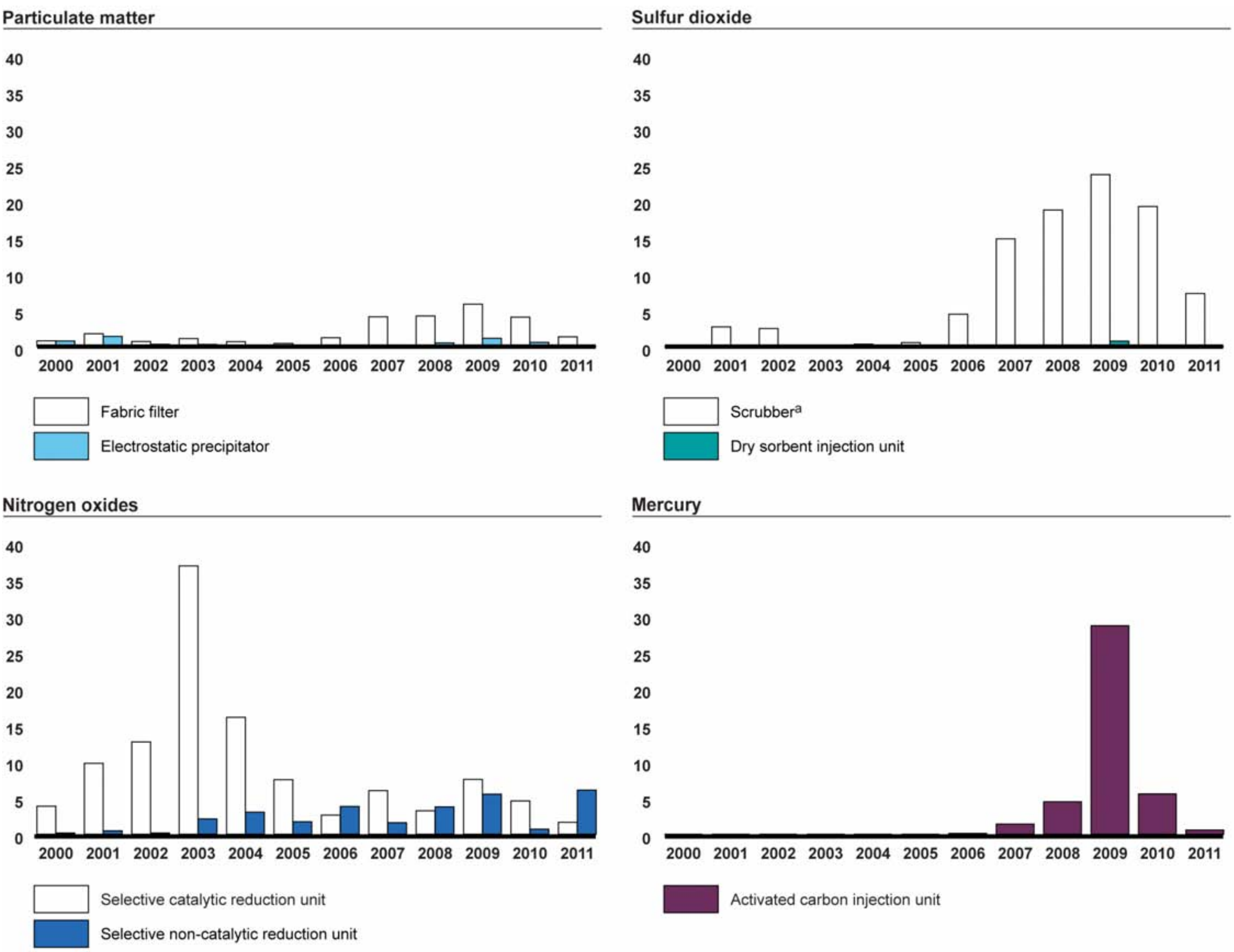
[b]Another approach to reducing SO_2, mercury, and acid gas emissions from generating units is to switch from using coals with higher contents of these substances to coals with lower contents, or to blend coals.

[c]Low-NO_x burners may also be used in conjunction with postcombustion controls for NO_x.

[d]Mercury can be removed through various controls. For example, wet scrubbers remove mercury, and particulate matter control equipment can remove mercury that is bound to the ash.

Figure 9 shows the capacity of coal-fueled generating units that were retrofitted with select controls from 2000 through 2011, and figures 10 and 11 show the percent of generating capacity with select controls by region.

Figure 9: Capacity of Coal-Fueled Generating Units Retrofitted with Select Air Pollution Controls, 2000-2011

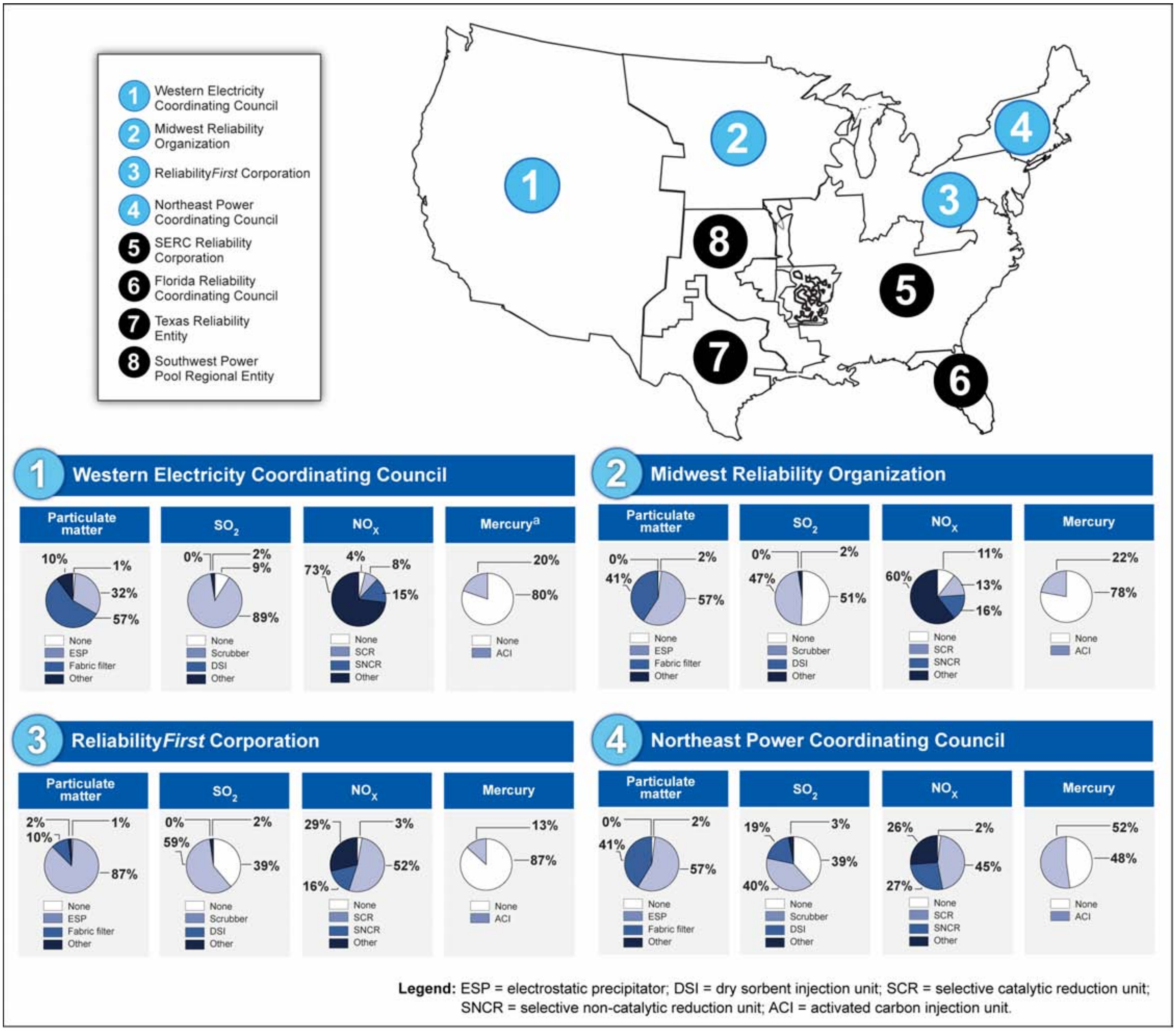


Source: GAO analysis of Ventyx data.

Note: Capacity is in thousand megawatts and includes units with over 25 megawatts of net summer capacity—the generating unit's capacity to produce electricity during the summer when electricity demand for many electricity systems and losses in efficiency are generally the highest. Net capacity figures exclude output used internally for plant operations.

[a]Scrubbers include wet, dry, and other types of units.

Figure 10: Percentage of Coal-Fueled Generating Capacity with Air Pollution Controls Installed by Region, as of April 9, 2012

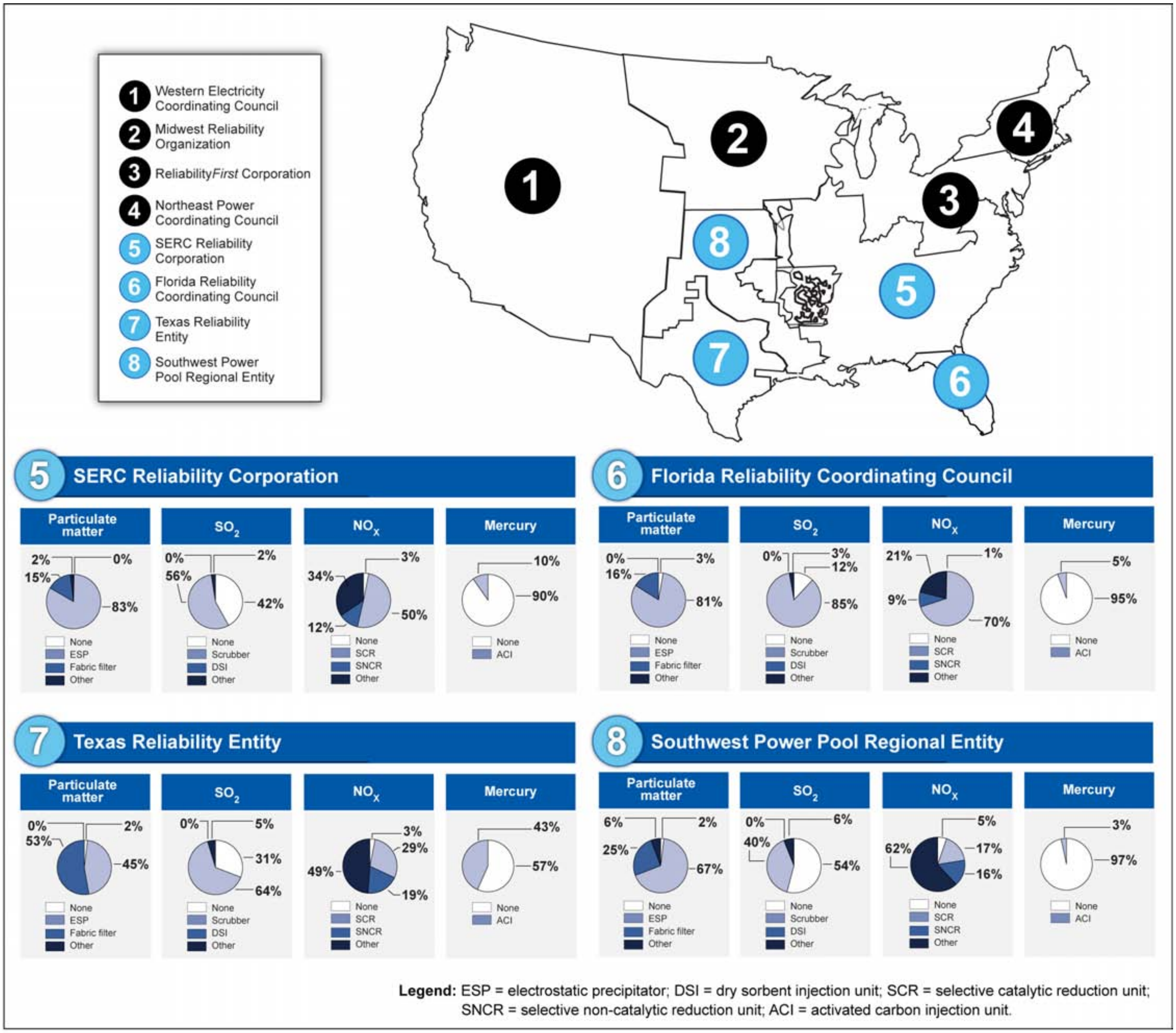


Sources: GAO analysis of Ventyx data, North American Electric Reliability Corporation, and Map Resources (map).

Note: Includes units with over 25 MW of net summer capacity—the generating unit's capacity to produce electricity during the summer when electricity demand for many electricity systems and losses in efficiency are generally the highest. Net capacity figures exclude output used internally for plant operations.

[a]In addition, one unit with 85 MW capacity, 0.3 percent of the region's coal-fueled capacity, has a different mercury-specific control.

Figure 11: Percentage of Coal-Fueled Generating Capacity with Air Pollution Controls Installed by Region, as of April 9, 2012



Sources: GAO analysis of Ventyx data, North American Electric Reliability Corporation, and Map Resources (map).

Note: Includes units with over 25 MW of net summer capacity—the generating unit's capacity to produce electricity during the summer when electricity demand for many electricity systems and losses in efficiency are generally the highest. Net capacity figures exclude output used internally for plant operations.

Appendix V: Comments from the Federal Energy Regulatory Commission

Note: GAO comments supplementing those in the report text appear at the end of this appendix.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE CHAIRMAN

July 3, 2012

Mr. Frank Rusco
Director Natural Resources and Environment
United States Government Accountability Office
441 G Street, NW
Washington, DC 20548

Dear Mr. Rusco:

Thank you for your June 6, 2012 electronic transmission of the draft report, *EPA Regulations and Electricity: Better Monitoring by Agencies Could Strengthen Efforts to Address Potential Challenges.* I appreciate the opportunity to comment on this draft report.

See comment 1.

In general, the draft report provides useful discussion of this issue. However, the draft report's ultimate conclusions and recommendations are incorrect in two ways. As more fully described below, it does not take into account a number of actions the Federal Energy Regulatory Commission (FERC or Commission) has taken as the electricity industry works to comply with new Environmental Protection Agency (EPA) regulations. We also publicly committed to working closely with industry, the states and other agencies to address any issues that arise. The Commission is already implementing a variety of policies, including those you recommend, to ensure that our electricity system remains reliable. Here are a few of the steps we have taken that were not discussed in the draft report. I respond to the report's specific recommendations in more detail below.

- The Commission has already held one conference specifically to examine the processes that Planning Authorities and other entities use to identify and address reliability concerns that may arise in the course of compliance with EPA regulations. To the extent additional analysis or evidence would aid the Commission's efforts to monitor and act on these issues, we will hold additional conferences or workshops.
- The Commission recently issued a Policy Statement detailing how our coordination with EPA on compliance to the new mercury and air toxic standards rule will work.
- The Commission participates in a regular public forum with state commissioners, the National Association of Regulatory Utility Commissioners (NARUC)/FERC Forum on Reliability and the Environment.

-2-

See comment 1.

- The Commission and its staff review plans, reports and other information generated by the Planning Authorities, industry and other stakeholders regarding the impact of compliance with EPA regulations.
- Commission staff routinely communicates with the EPA and the Department of Energy (DOE) on this topic.
- The Commission staff, DOE, and EPA are working to establish a more formalized approach to continued coordination and discussion of issues arising from the industry's response to EPA regulations.

Should the final report not take into account these actions, it will be incorrect in failing to recognize both that the Commission had undertaken before issuance of the draft report many of the actions the draft report proposes and that the Commission has taken additional actions after issuance of the draft report in furtherance of its recommendations.

See comment 2.

As noted in the report, the Commission has an important role in overseeing the reliability of the bulk-power system. I take that role seriously, and have taken several steps to discuss issues concerning the EPA regulations and reliability with industry and EPA and DOE. As a part of this role, on May 17, 2012, the Commission issued a policy statement outlining how it will advise the EPA on requests for additional time for electric generators to comply with the new EPA mercury and air toxics standards rule. The Commission issued this policy statement after considering a staff white paper on the subject and numerous comments received on the staff white paper. Although my staff shared these documents with your office, neither the January white paper nor the Policy Statement was discussed in the draft report. A copy of the Policy Statement is enclosed again. Below, I address the recommendations in the draft report in several important respects.

See comment 3.

The draft report first recommends that FERC, EPA and DOE develop and document a formal, joint process to monitor industry's progress in responding to the EPA regulations. I agree with the goal of open communication and have had Commission staff engage extensively with EPA and DOE on these issues. Commission staff has had numerous meetings with EPA and DOE to discuss the issues involved and continues to meet with EPA and DOE. With respect to creating a formal process, as an independent agency, the Commission cannot dictate the sharing of information with and by other parts of the government. The Commission staff, DOE, and EPA are working to establish a more formalized approach to continued coordination and discussion of issues arising from the industry's response to EPA regulations to the extent our authority allows.

-3-

See comment 4.

Further, the draft report is incorrect that the Commission has had only informal coordination with power companies and others about their actions in response to the regulations. The Commission has held numerous meetings with representatives from EPA, DOE and the industry on these issues, including two public meetings. The Commission held a reliability conference on November 30, 2011 to discuss the processes that Planning Authorities and other entities use to identify and address reliability concerns that may arise in the course of compliance with EPA regulations. Representatives from EPA and DOE participated in this conference and GAO representatives were invited to and attended this conference. At this conference, the Commission addressed issues such as how reliability aspects of EPA's proposed and final regulations should be addressed, what local or regional processes are used to plan for emerging issues such as the EPA regulations, and how the industry is incorporating the EPA regulations into this process. The Commission received numerous written comments following this reliability conference.

The Commission has also joined with NARUC to convene an ongoing Forum to explore reliability issues stemming from new and pending environmental rules for the power sector. FERC and NARUC initiated the Forum as part of an effort to determine how prepared the electric utility industry will be to meet upcoming rules and requirements on emissions reductions. Future meetings will coincide with NARUC's three yearly meetings. The first meeting of the FERC-NARUC Forum on Reliability and the Environment took place on February 7, 2012 and the next meeting will be held in July.

See comment 5.

With respect to monitoring the industry's progress, the Policy Statement noted that the existing processes used by the Planning Authorities to conduct reliability assessments, which are based on the NERC planning standards and performed under NERC's oversight, appear to be sufficient. The Commission will continue to monitor Planning Authorities' efforts on these matters. Since issuance of the Policy Statement, Commission staff, EPA, and DOE have participated in several conference calls with RTOs to discuss their efforts to plan the system for future need, including implementation of the EPA rules. Future meetings are planned, and staff has scheduled a meeting with the Planning Authorities in the Southeast to discuss their planning activities. As provided in the Policy Statement, the Commission has committed that Commission staff is available to Planning Authorities and participants in these processes for consultation on these matters.[1]

[1] *The Commission's Role Regarding the Environmental Protection Agency's Mercury and Air Toxics Standards*, 139 FERC ¶ 61,131 at n.17 (2012) (Policy Statement).

See comment 5.

Further, the Policy Statement affirms that the Commission is engaged in other efforts to monitor the impact of EPA regulations generally on bulk-power system reliability. For example, the Commission and its staff will continue to review plans, reports and other information generated by the Planning Authorities, industry and other stakeholders regarding the impact of compliance with EPA regulations. The Commission stated that to the extent additional analysis or evidence would aid the Commission's efforts to monitor these issues, it will consider holding additional reliability conferences or workshops.[2]

Finally, the Commission's Policy Statement makes clear that the lines of communication should remain open. It specifically provided that Commission staff will also be available to communicate with the EPA on any reliability-related issues to aid the EPA in its consideration of these issues.[3] The Policy Statement also identified types of information industry applicants could provide to assist the Commission in its timely review of requests for Administrative Orders from the EPA.

See comment 6.

The second recommendation in the draft report is for me as the Chairman of the Commission to assess the adequacy of existing RTO market rules and similar rules of non-RTO planning authorities. I believe this recommendation is founded on incorrect information because I have already met it. The Commission continually assesses the rules of the entities over which it has jurisdiction, and it has specifically explored whether changes are needed to respond to the EPA regulations.

With respect to analyzing tariffs and market rules in light of the EPA regulations, the Commission's November 30, 2011, reliability conference addressed this exact issue. The Commission explicitly asked participants what market structures and tariff rules are used to address local and regional reliability issues that may arise from generation retirements potentially triggered by EPA regulations and whether any changes to market and tariff rules are needed. The Commission also asked participants to address if they have the right tools to identify any problems that may arise and what, if any, other process changes could help address reliability-related requests for exemptions from the EPA regulations. During the reliability conference, Commissioners questioned panelists on whether new tools are needed.[4] The overwhelming response from panelists and

---

[2] *Id.* at P 23.
[3] *Id.* at n.23.
[4] *See, e.g.,* Reliability Technical Conference, Nov. 29, 2011 Tr. 263, ln 19 – 264, ln. 4.

-5-

commenters was that no significant changes are needed to the market rules at this time. Thus I have already fulfilled the draft report's second recommendation.

See comment 6.

Further, the Commission continually assesses the tariffs pursuant to which public utilities operate. For example, in its recent rulemaking evaluating the adequacy of transmission planning processes, the Commission evaluated its existing regulations and proactively required public utility transmission providers to amend their planning processes to address compliance with public policy requirements. Public policy requirements in this context can include requirements under EPA regulations.[5] By October 2012, public utility transmission providers must submit to the Commission compliance filings describing the process by which they will evaluate potential solutions to transmission needs driven by public policy requirements. The Commission specifically acknowledged that evaluation of transmission needs driven by public policy requirements could require the gathering of additional information from interconnected generators regarding retirements. The Commission invited public utility transmission providers to include in their compliance filings amendments to existing tariff provisions necessary to gather such information.[6]

See comment 7.

The Commission has also met the draft report's recommendation that the Commission consider the presence or absence of demand response when making key decisions about electricity markets and that the Commission should be able to quickly and effectively review whether steps should be taken to require RTOs or other market participants to secure additional demand response resources. When I first came to the Commission, I stated my belief that demand resources could reduce the costs of electric service and provide several other benefits to consumers. My colleagues and I have worked to provide the opportunity for demand resources to participate in wholesale markets, assist in efficient transmission service and maintain the reliability of the electric system. The Commission has issued several regulations to eliminate barriers to demand response participation in organized markets. For example, Order No. 719 made several reforms to eliminate barriers to demand response participation in organized energy markets and to ensure that demand response is treated comparably to other resources.[7] Order No. 745 modified the Commission's regulations concerning

---

[5] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 215 (2011).
[6] *Id.* at P 211, n.190
[7] Order No. 719, FERC Stats. & Regs. ¶ 31,281.

-6-

compensation for demand response.[8] That rule provides more resource options for efficient and reliable system operation; it encourages new entry and competition in energy markets, and it spurs the deployment of new technologies.

See comment 8.

The draft report next asserts that the Commission does not have plans to evaluate whether changes proposed by one RTO may be useful at others. I disagree with this recommendation. Each RTO market is structured differently and, where appropriate, the Commission has allowed regional approaches that make sense in the context of each RTO's market. What works in one RTO may not in another. Dictating a federal one-size-fits-all approach on matters related to EPA regulations could be problematic, particularly when the Commission already has explored whether changes are needed.

See comment 9.

Further, the draft report asserts that, if there are a larger number of local reliability challenges, the Commission may be less able to effectively and quickly manage reviewing several types of issues. However, the Commission routinely processes the filings it receives in a timely, effective manner. For example, applications for cost recovery for transmission investments and reliability-must run agreements will generally be made under section 205 of the Federal Power Act (FPA). Section 205 cases are proposals by public utility service providers to adopt or revise rates, terms or conditions for Commission-jurisdictional power or transmission services. The statutory deadline for issuance of section 205 orders typically is 60 days from the date of filing, and the Commission has a long history of meeting this deadline.

See comment 10.

The draft report is also concerned about requests for reliability-critical status from plants seeking an additional year for compliance under the EPA's MATS Rule. As stated above, the draft report does not acknowledge that Commission staff issued a white paper in January concerning this issue or that the Commission recently issued a Policy Statement outlining the procedure for reviewing these filings. As stated in the Policy Statement, these procedures were specifically crafted to ensure that the Commission can provide timely comments to the EPA.

Thank you again for the opportunity to comment on your draft report. While, the draft report provides useful discussion of this issue, the ultimate conclusions and recommendations are incorrect because they ignore actions the Commission has taken and continues to take regarding these issues. As the

[8] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 76 Fed. Reg. 16,658 (Mar. 24, 2011), FERC Stats. & Regs. ¶ 31,322 (2011).

-7-

Commission stated in its recent Policy Statement, the Commission intends to continue addressing these issues with state commissions in a regular public forum, the NARUC/FERC Forum on Reliability and the Environment. The Commission and its staff will also continue to review plans, reports and other information generated by the Planning Authorities, industry and other stakeholders regarding the impact of compliance with EPA regulations, and to communicate with the EPA and DOE on this topic. To the extent additional analysis or evidence would aid the Commission's efforts to monitor these issues, we will consider holding additional reliability conferences or workshops. The Commission also seeks to engage industry and other federal agencies on issues relating to electric reliability. FERC's door is always open and we have consistent interaction with industry on any number of reliability and market concerns. Finally, in recognition of the recommendation in the draft report, Commission staff, DOE, and EPA are working to establish a more formalized approach to continued coordination and discussion of issues arising from the industry's response to EPA regulations. The final report should acknowledge these actions and not repeat the draft report's incorrect assertions. I am happy to discuss these issues with you at any time.

Sincerely,

Jon Wellinghoff
Chairman

The following are GAO's comments on the Federal Energy Regulatory Commission's letter dated July 3, 2012.

GAO Comments

1. We recognize that FERC has taken a number of positive actions related to the EPA regulations, and we have described these in our draft and final report. We have made some clarifying changes and, in one case, added language about an example we had not previously described in the report in response to these comments.

2. The scope of FERC's policy statement is limited to describing how FERC intends to provide advice to EPA on requests for administrative orders to bring a source into compliance with MATS within 1 year. It provides a useful description of FERC's role with respect to this tool for addressing potential reliability challenges, but it does not establish a formal, documented process for FERC's overall monitoring effort or for its coordination with EPA and DOE. We added a description of FERC's policy statement where we describe FERC's role with respect to MATS in response to this comment.

3. We agree that multiagency coordination can be difficult. When we met with FERC, EPA, and DOE during the course of our audit work, the agencies had not documented a formal process for monitoring. In response to our draft report, these agencies said they are working to establish such an approach. We commend these agencies for taking this step and believe it is important that they complete this effort. We acknowledge there may be limits on the extent to which agencies can collaborate and clarified our recommendation accordingly.

4. We acknowledge that FERC has gathered views on the potential implications of these regulations from various affected parties, including at formal events such as FERC's 2011 technical conference and the February 2012 forum with state regulators. Our observation from attending these events is that they fostered a useful exchange of ideas and perspectives about the potential implications of the EPA regulations. However, the actual implications will only be known once electricity generating unit owners finalize their plans for responding to the regulations and begin to take steps to retrofit or retire units—which will occur over the next several years. We believe that additional monitoring will be important and that the actions noted by FERC do not represent the type of formal, documented process that will be needed for successfully monitoring industry's progress in responding to the regulations or for FERC’s coordination with DOE and EPA in this effort. We believe there are risks to relying on informal

mechanisms and that a formal, documented process could help strengthen FERC's future efforts at identifying potential problems. As such, we made no changes in response to this comment.

5. We believe that the NERC-overseen reliability assessments, plans and reports from other stakeholders, as well as conferences and workshops, can all be useful in an overall monitoring effort. We encourage FERC to work with NERC and other stakeholders in monitoring industry progress to the extent that FERC determines such activities to be useful. We maintain that FERC should formalize this process and document it if the agency intends for this monitoring to continue in the future. We made no change in response to this comment.

6. We acknowledge that FERC periodically performs various assessments of the adequacy of existing RTO market rules and similar rules of non-RTO system planners and, where FERC believes it is appropriate, encourages changes. However, based on our conversations with FERC officials, FERC had not proactively assessed the adequacy of system planner rules in light of the EPA regulations to determine whether changes are needed or if improvements at one system planner could be useful at another. We also acknowledge that there was a useful exchange of ideas and perspectives about the need for potential changes in market rules at FERC's technical conference, but we do not believe that the gathering of these views is a substitute for an assessment by FERC of the adequacy of these rules. In addition, FERC's recent rulemakings are positive steps, but they do not reflect an assessment of whether rules need to be modified in light of the EPA regulations to ensure timely, cost-effective mitigation of potential reliability challenges that may be associated with the regulations. We made no change in response to this comment.

7. Neither the draft report, nor the final report recommends that FERC consider the presence or absence of demand response when making key decisions about electricity markets. FERC’s comment refers to text in our draft report that referred to a recommendation in our 2004 report on demand response. We made this reference to highlight that demand response is a tool that could lower demand for electricity to mitigate the price or reliability implications of the EPA regulations and to note that FERC has taken a number of steps to facilitate broader use of demand response among RTOs. As noted in the conclusion of this report, we believe that demand response could provide an important mechanism that could mitigate potential reliability

challenges, should they arise. As such, it may be useful for FERC to consider whether there are certain approaches related to demand response at one or more RTOs that could be encouraged elsewhere or whether the presence or adequacy of demand response in a market should be used when making decisions regarding market rules. We made no change in response to this comment.

8. We do not suggest that a one-size-fits-all approach would be best, and believe efforts to develop the RTOs and other institutions requires leveraging prior entities' experiences. FERC may have the opportunity to take a more proactive role in narrowing these differences to the benefit of market participants overseen by FERC and the consumers who are ultimately served by these markets. We made no change in response to this comment.

9. We do not assert that FERC will be unable to meet its statutory deadlines for review of transmission investments and reliability must-run agreements. Rather, we suggest that information from a formal, documented monitoring effort could help alert agencies in advance if a larger or smaller than expected number of reliability challenges arises, which could be useful for managing its staffing and operations. We made no change in response to this comment.

10. We agree that FERC’s policy statement provides clarity about the process FERC intends to take to provide timely comments to EPA on requests for administrative orders to bring a source into compliance with MATS within 1 year. However, we continue to believe that a documented, formal monitoring process—by giving FERC insight into the extent of potential reliability challenges—could aid FERC in managing its process for providing input to EPA. We made no change in response to this comment.

Appendix VI: Comments from the Department of Energy

Department of Energy
Washington, DC 20585

July 3, 2012

Mr. Frank Rusco
Director
Natural Resources and Environment
U.S. Government Accountability Office
Washington, DC 20548

Dear Director Rusco:

The Department of Energy (DOE) appreciates the opportunity to respond to the Government Accountability Office's (GAO) Draft Audit Report "EPA Regulations and Electricity: Better Monitoring by Agencies Could Strengthen Efforts to Address Potential Challenges."

DOE's response to the Report's draft recommendation that involves DOE is as follows:

Recommendation 1: "To further strengthen agency efforts to understand whether existing tools are adequate or additional tools are needed, we recommend that the Chairman of FERC, the Secretary of Energy, and the Administrator of the EPA develop and document a formal, joint process to monitor industry's progress in responding to the EPA regulations until at least 2017. Each agency, to the extent practical, should leverage resources and share the results of its efforts with the other agencies. The agencies should consider providing Congress with the results of their monitoring efforts, including whether additional statutory authority is needed to address any potential adverse implications."

Response: DOE concurs with the recommendation to "develop and document a formal, joint process to monitor industry's progress in responding to the EPA regulations…" among FERC, DOE, and EPA. An effort to document through a formal process the current (as the draft report notes) coordinated monitoring by our three agencies is currently underway. DOE agrees that coordination between it, the Environmental Protection Agency (EPA) and the Federal Energy Regulatory Commission (FERC) is an important part of successfully addressing any potential reliability challenges within the electricity sector as a result of EPA's recent suite of regulations.

Additionally, the Department will continue to offer technical assistance to states and other stakeholders. Such technical assistance is expected to help inform, rather than direct, decisions regarding implications from EPA's regulations. This technical assistance may relate to the retire vs. retrofit decision for generation units over which a state has oversight, including options for replacement energy in case of a retirement. For

1

Printed with soy ink on recycled paper

example, two weeks ago DOE, at the invitation of the Ohio Public Utilities Commission, provided input into a commission workshop on combined heat and power, and hosted a Midwest combined heat and power dialogue meeting. Earlier this year, DOE provided assistance to another state on technology options on the retire vs. retrofit issue, as well helping a state's utility commission think through the implications for the electricity planning process it oversees in light of the EPA regulations.

Finally, with respect to DOE's emergency authority under section 202(c) of the Federal Power Act, DOE views this authority as a tool of last resort to address reliability emergencies when all other options have been exhausted. DOE has issued an emergency order in only one case where environmental regulations played a direct role. In this instance, DOE worked closely with both EPA and the state environmental agency to ensure that the reliability emergency could be resolved while achieving maximum environmental protection. Should a verifiable reliability emergency arise in the future that may involve DOE's emergency authority, DOE will continue to coordinate with other agencies, as appropriate, to ensure that the emergency can be resolved in accordance with other applicable statutes and regulations.

Thank you, again, for the opportunity to provide comment on the draft report. We look forward to receiving your final report.

Sincerely,

Patricia A. Hoffman

Patricia A. Hoffman
Assistant Secretary
Office of Electricity Delivery and Energy Reliability
U.S. Department of Energy

2

Appendix VII: Comments from the Environmental Protection Agency

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL - 5 2012

DEPUTY ADMINISTRATOR

Mr. Frank Rusco
Director, Natural Resources and Environment
U.S. Government Accountability Office
441 G Street, N.W., Room 2T23
Washington, D.C. 20548

Dear Mr. Rusco:

On behalf of the U.S. Environmental Protection Agency, I thank you for your attention to the important issues surrounding implementation of the EPA's power plant rules and their effect on the electricity market and the power system. These rules will provide very substantial public health benefits for millions of Americans as well as important protections for the environment. The rules are achievable using technologies and practices that are widely available and are projected to have only a modest effect on electricity prices. In keeping with our strong track record in this area, the EPA continues to take great care, in close coordination with other federal agencies and outside stakeholders, to ensure these rules are implemented in a manner that does not adversely affect the reliability of the electric power system.

At the outset, I want to acknowledge the U.S. Government Accountability Office's recommendation that the EPA work with the U.S. Department of Energy and the Federal Energy Regulatory Commission to further coordinate, formalize and document our ongoing activities to monitor industry's progress with regard to the implementation of EPA regulations and to share information among the three agencies. As explained in greater detail below, I am pleased to report that this effort is already underway.

The GAO report covers four EPA rulemakings. Two of them (the cooling water intake rulemaking under section 316(b) of the Clean Water Act and the coal combustion residuals rulemaking under the Resource Conservation and Recovery Act) have been proposed and are still under revision in response to public comment (not yet final). The two final rules are the Cross State Air Pollution Rule and the Mercury and Air Toxics Standards, promulgated under the Clean Air Act. Of these final rules, only MATS requires on a plant-by- plant basis significant investments in pollution control technologies within a limited time frame. As such, MATS is appropriately the focus of the GAO's report.

The MATS rule prescribes standards under section 112 of the Clean Air Act to control emissions of mercury and other toxic air pollutants from coal- and oil-fired power plants, which collectively are among the largest sources of such pollution in the United States. MATS will substantially reduce emissions of pollutants that contribute to neurological damage, cancer, respiratory illnesses, premature death and other health risks, and it will produce important health benefits for millions of Americans, including children. The EPA estimates that beginning in 2016 these new standards will avert up to 11,000 premature deaths, 4,700 heart attacks and 130,000 asthma attacks every year with monetized benefits far exceeding the estimated costs.

More than half of the coal-fired capacity in the country already has modern pollution control technologies in use. Under MATS, facilities that do not already have adequate controls for mercury, acid gases and heavy metals will need to install or upgrade controls. The technologies to reduce these emissions are widely available and cost-effective. However, while MATS does not require any plant to retire, some plants will make an economic decision to close rather than invest in pollution control, especially plants that are older and seldom used today. New capacity will come into the market, including demand resources.

A variety of utilities and other stakeholders have expressed concerns that these retirements have the potential to impact electric reliability. The EPA has taken these concerns very seriously and, as explained below, has taken a number of steps to address them. It is essential, however, to make clear to readers that while the primary focus of the GAO report is the impact on grid reliability of the power sector's compliance with EPA regulations, EPA regulations are by no means the largest factor driving changes in the sector.

The changes taking place in the electricity market today, independent of the EPA's rules, are remarkable and represent a significant shift from just a few years ago. These include a striking decline in natural gas prices, rising coal prices and reduced demand for electricity. In addition, a majority of coal plants in the fleet that have been in service for 40 years or longer, and many of these older plants are significantly less efficient than newer generation, resulting in very low utilization rates. As a result, the owners of some fossil fuel-fired power plants appear to be finding that these plants' revenues no longer cover their operating costs, leading, in turn, to business decisions to retire these plants.

These market drivers would have significant impacts even in the absence of the EPA's regulations. In fact, many observers think that the EPA's rules are relatively minor drivers of the important changes that are occurring today.[1] A recent economic modeling study concluded:

> This analysis shows that the change between 2009 and 2011 in projections of natural gas supply and electricity demand has a much bigger effect on electricity prices, total generation, and generation by fuel than does the introduction of CSAPR [the Cross State Air Pollution Rule] or MATS. Indeed for electricity prices, these secular changes drive effects that are generally more than 5 times greater than the effects of CSAPR or MATS. That multiple is even bigger when comparing the effects on electricity consumption and generation from coal.[2]

It is important for readers to understand the impact of the EPA's standards in this broader market context. For example, many recent announcements of "retirements" by utilities are actually merely accelerations of retirements that were already planned or may have occurred anyway in response to continuing shifts in market conditions. Notably, in many cases these utilities are seeking to close some of this capacity years in advance of the earliest MATS compliance deadline.

We also think it is important to provide further context for some of the studies listed in the report that project retirements and other impacts, which the GAO examined to consider "the range of potential

[1] See for example: Susan Tierney, "Why Coal Plants Retire: Power Market Fundamentals as of 2012," The Analysis Group, February 6, 2012; James Bradbury, "U.S. Electricity Markets Increasingly Favor Alternatives to Coal" April 2012, and IHS CERA, Market Briefing, "Sharply Lower Natural Gas Prices Reshape the US Power Supply Stack, " April 10, 2012.
[2] Burtraw et al., "Secular Trends, Environmental Regulations and Electricity Markets", RFF Discussion Paper (March 2012).

implications of the four regulations." While the EPA's regulatory analyses are based on peer-reviewed models, use accurate inputs reflecting the EPA's rules and are transparent about their assumptions, not all of the other studies the report examined meet these standards. For example, many studies were based on the proposed version of the MATS rule and therefore do not take into account the changes to the particulate matter standard which were made in the final rule, reducing likely costs for many firms. Similarly, the NERA study does not provide its electricity demand forecast, its natural gas and coal supply/price projections or details on treatment of key pollution control requirements, making it difficult to ensure that it is accurately reflecting the rules or current market dynamics.

Although the EPA's rules are not the major driver of ongoing changes in the power sector, we have taken a number of steps to assure that our rules do not interfere with electric reliability. Before MATS was finalized, the EPA and the DOE both conducted analyses of electric generation resources.[3] Both the EPA's and the DOE's analyses demonstrate that the vast majority of, if not all, sources would be able to meet the MATS requirements within the time frames provided under the Clean Air Act. These studies indicated that large-scale reliability problems as a consequence of MATS were extremely unlikely, consistent with the GAO's assessment of the available studies that "[t]he actions power companies take in response to the four key EPA regulations are not likely to cause widespread reliability challenges." The EPA recognizes that these studies could not assure that there would not be localized reliability concerns and accordingly is focused on working with utilities and grid-planning organizations to help them anticipate and mitigate any such issues that may arise.

In response to concerns about possible local-scale reliability impacts and consistent with a December 2011 Presidential Memorandum addressing MATS implementation, the EPA provided several flexibilities to assure that MATS implementation could proceed without compromising the stability of the electric power grid. The standards themselves contain several features to provide owner operators of power plants flexibility in how they are met.[4] The EPA also provided significant flexibilities with regard to compliance timing.

Under the Clean Air Act, permitting authorities (which generally are the states) can grant a fourth year to come into compliance – in addition to the three years provided to all sources – where necessary for the installation of controls. In the final rule, the EPA indicated that permitting authorities should make this fourth year broadly available and described in detail the wide range of situations where we believe they can do so. These include situations in which additional time is needed to install pollution control equipment, to construct on- or off-site replacement power or to upgrade transmission to avert reliability problems. The EPA has reached out to states and permitting authorities to help ensure that the fourth

[3] Environmental Protection Agency (2011). "Resource Adequacy and Reliability in the IPM Projections for the MATS Rule" http://www.epa.gov/ttn/atw/utility/revised_resource_adequacy_tsd.pdf
Department of Energy (2011). "Resource Adequacy Implications of Forthcoming EPA Air Quality Regulations" http://energy.gov/sites/prod/files/2011%20Air%20Quality%20Regulations%20Report_A_120911.pdf

[4] For example, to meet the acid gas standard plants can meet a limit for the acid gases or they can meet an alternative standard for SO2 that would provide equivalent reductions. Also, for all standards, existing plants can choose to meet an input standard expressed as pounds of pollutant emitted per unit of heat input or an output-based standard expressed as pounds of pollutant per unit of electricity generated. The standards themselves can be met by averaging among all the units in the same subcategory at a plant. Each unit does not have to meet the standard. Finally the standards are expressed as averages over time, rather than as limits not-to-be exceeded at any time. Other rules also have built in flexibilities that can help to avoid reliability issues. CSAPR allows owners and operators to determine their own emissions level subject to a limitation on total Electric Generating Utility emissions within that state; this market-based flexibility includes allowance trading across units within and between states. The 316(b) proposal grants permitting authorities flexibility to tailor compliance timelines to help avoid negative impacts on reliability.

3

year for compliance is broadly available. Based on this outreach, our understanding is that requests for the fourth year extension for air toxic standards have been handled well by states in the past, and we are not aware of any concerns. We have encouraged the states to continue processing these requests as they have done in the past. Both EPA headquarters and regional office staff members are available to quickly provide assistance and to answer any questions. As a result, the EPA estimates that sources generally will have until spring of 2016 to comply – one year longer than our analysis indicates is necessary for most sources.

In addition, the EPA is providing a clear pathway for units that are shown to be critical for electric reliability to obtain a schedule to achieve compliance within up to an additional year beyond the four years mentioned above. This pathway is set forth in a policy memorandum from the EPA's Office of Enforcement and Compliance Assurance.[5] As stated above, the EPA believes there will be few, if any, situations in which this pathway will be needed. In addition, in the unlikely event that there are situations where sources that do not fall into any of these categories cannot come into compliance on a timely basis, the EPA will address them on a case-by-case basis, at the appropriate time, to determine the appropriate response and resolution. This is consistent with its longstanding historical practice under the Clean Air Act.

Consistent with the Presidential Memorandum issued on December 21, 2011, the EPA is working closely with DOE and FERC, grid planning authorities, state public utility commissions and a range of other power-sector stakeholders to ensure early and coordinated planning and implementation of MATS requirements in a manner that maintains electric reliability. We are meeting regularly and frequently with FERC and DOE toward this end. We are also closely monitoring the implementation of MATS, primarily through regular communication with the Regional Transmission Organizations and other planning authorities that are responsible for grid planning and the assessment and mitigation of grid reliability concerns. We are holding regularly scheduled meetings between the three federal agencies and the RTOs, with a particular focus on the four key regions most affected by MATS. We are engaging in joint meetings with other planning authorities, the state regulatory agencies and the North American Electric Reliability Corporation and the NERC-affiliated regional entities, to monitor and address reliability issues that may arise. These have been productive exchanges that provide information that will help the EPA, the DOE and FERC to anticipate potential concerns well in advance, to better target our outreach and engagement with key stakeholders and to ensure that we are adequately prepared to address any reliability concerns that may arise.

Again, we recognize and appreciate GAO's recommendation that the EPA continue to work with the DOE and FERC to further coordinate, formalize and document our ongoing monitoring and outreach activities. As outlined above, the agencies' coordination, outreach and monitoring efforts have grown progressively more extensive and regularized over time. Going forward, we expect to continue to develop these joint efforts as well as to further formalize and document them, consistent with your recommendations.

[5] EPA Memorandum December 16, 2011. "The Environmental Protection Agency's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercury and Air Toxics Standard" http://www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf

4

In closing, I wish to express our appreciation for the professionalism of GAO staff during this inquiry. We look forward to the final report from the GAO.

Sincerely,

Bob Perciasepe

Bob Perciasepe

Attachment

cc: Quindi Franco, Analyst-in-Charge, Government Accountability Office
Bobbi Trent, GAO Liaison Team, EPA Office of the Chief Financial Officer
Mark T. Howard, GAO Liaison Team, EPA Office of the Chief Financial Officer

5

Appendix VIII: GAO Contacts and Staff Acknowledgments

GAO Contacts

Frank Rusco, (202) 512-3841 or ruscof@gao.gov
David C. Trimble, (202) 512-3841 or trimbled@gao.gov

Staff Acknowledgments

In addition to the individuals named above, Jon Ludwigson (Assistant Director), Mike Armes, Melinda Cordero, Philip Farah, Quindi Franco, Cindy Gilbert, Paige Gilbreath, Michael Hix, Mitch Karpman, Karen Keegan, Alison O'Neill, Madhav Panwar, Kendal Robinson, Jeanette Soares, and Kiki Theodoropoulos made key contributions to this report.

GAO's Mission

The Government Accountability Office, the audit, evaluation, and investigative arm of Congress, exists to support Congress in meeting its constitutional responsibilities and to help improve the performance and accountability of the federal government for the American people. GAO examines the use of public funds; evaluates federal programs and policies; and provides analyses, recommendations, and other assistance to help Congress make informed oversight, policy, and funding decisions. GAO's commitment to good government is reflected in its core values of accountability, integrity, and reliability.

Obtaining Copies of GAO Reports and Testimony

The fastest and easiest way to obtain copies of GAO documents at no cost is through GAO's website (www.gao.gov). Each weekday afternoon, GAO posts on its website newly released reports, testimony, and correspondence. To have GAO e-mail you a list of newly posted products, go to www.gao.gov and select "E-mail Updates."

Order by Phone

The price of each GAO publication reflects GAO's actual cost of production and distribution and depends on the number of pages in the publication and whether the publication is printed in color or black and white. Pricing and ordering information is posted on GAO's website, http://www.gao.gov/ordering.htm.

Place orders by calling (202) 512-6000, toll free (866) 801-7077, or TDD (202) 512-2537.

Orders may be paid for using American Express, Discover Card, MasterCard, Visa, check, or money order. Call for additional information.

Connect with GAO

Connect with GAO on Facebook, Flickr, Twitter, and YouTube. Subscribe to our RSS Feeds or E-mail Updates. Listen to our Podcasts. Visit GAO on the web at www.gao.gov.

To Report Fraud, Waste, and Abuse in Federal Programs

Contact:

Website: www.gao.gov/fraudnet/fraudnet.htm
E-mail: fraudnet@gao.gov
Automated answering system: (800) 424-5454 or (202) 512-7470

Congressional Relations

Katherine Siggerud, Managing Director, siggerudk@gao.gov, (202) 512-4400, U.S. Government Accountability Office, 441 G Street NW, Room 7125, Washington, DC 20548

Public Affairs

Chuck Young, Managing Director, youngc1@gao.gov, (202) 512-4800
U.S. Government Accountability Office, 441 G Street NW, Room 7149
Washington, DC 20548