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Reliability in the Electricity Industry under New Environmental Regulations

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RESOURCES FOR THE FUTURE

Reliability in the Electricity Industry under New Environmental Regulations

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Abstract

Implementation of new environmental regulations in the electricity industry has triggered concerns about system reliability. We find these regulations are unlikely to create the shock to the system as some worry. They lead to little change in generation capacity. The large costs associated with investments in pollution control technologies are partially offset by a decrease in the cost burden associated with tradable emissions allowances. The combined effects contribute to a 1 percent increase in retail electricity prices and a decrease in producer profits of about $3–$5 billion in 2020. Though it varies across scenarios and regions, over the simulation horizon, consumers pay approximately 70 percent of total costs. In 2020, for example, total annual costs are between $6.6 billion and $7.1 billion. The investment in pollution controls leads to substantial reductions in emissions of mercury and sulfur dioxide.

Key Words: emissions trading, mercury, sulfur dioxide, air toxics

JEL Classification Numbers: Q41, Q52, Q58

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Reliability in the Electricity Industry under New Environmental Regulations

Dallas Burtraw, Karen Palmer, Anthony Paul, Blair Beasley, and Matt Woerman *

1. Introduction

The U.S. electricity industry is undergoing historic changes as a series of pent-up environmental regulations launched over the last two decades finally come to fruition. Now that they are reality, many observers have raised concerns about the cost and changes they may impose on the reliable performance of the electricity industry.

The two most important new rules are the Cross-State Air Pollution Rule (CSAPR), which regulates emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO_2) in the eastern half of the country, and the Mercury and Air Toxics Standards (MATS), which sets national emission rate limits for mercury and other toxic air pollutants. CSAPR replaces the Clean Air Interstate Rule (CAIR), which was promulgated in 2005 for implementation in 2010, but subsequently was sent back to the U.S. Environmental Protection Agency (EPA) for revision by the U.S. Court of Appeals for the D.C. Circuit. CSAPR was promulgated in 2011 and would have taken effect in 2012. However, it is now itself under judicial review and implementation is delayed. Similarly, MATS replaces the Clean Air Mercury Rule (CAMR) that was also promulgated in 2005 but was subsequently struck down by the courts. MATS was promulgated at the end of 2011, but most plants will have until 2016 to comply.

Across the industry, parties have invoked the term “reliability” to express concerns about the changes that are under way. This term is generally interpreted to suggest the potential for electricity supply disruptions, including a shortage of generation capacity or an inability to meet reliability standards. However, reliability of supply may be a misnomer because only exceptional circumstances would trigger supply disruptions. Depending on how these regulations are implemented and how the electricity industry and state-level regulators respond to them, it is much more likely the rules may affect the reliability of current electricity prices, industry

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revenues and costs, and profits. Coming into compliance with these regulations will alter investments in new generation capacity and system operations and will require additional investment in retrofit pollution control at existing facilities. These changes will vary by region of the country because some of the regulations are not national in scope and because of regional differences in electricity market regulation and current fuel use for electricity supply.

This paper examines these new environmental regulations, CSAPR and MATS, and their expected impact on measures of reliability, including generation, capacity, and reserve margins. We also examine the regulations' impact on key indicators of change in the electricity market, such as retail prices, producer surplus, and environmental outcomes. We do so using a sophisticated national electricity simulation model that accounts for investments, retirements, and operation of the electricity system under various environmental constraints and regulatory institutions. It is important to consider these issues in an equilibrium model because, in general, achieving reliability margins affects retail prices that feed back to affect the economics of investment decisions at existing and new facilities. For example, investments in retrofit environmental controls that do not appear economic at current prices may become so once market prices respond to the new regulatory environment.

We find that neither MATS nor CSAPR create the shock to the electricity system that some worry would lead to reliability problems. Generating capacity, including coal capacity, does not substantially decrease by 2020. However, the regulations do lead to large investments in pollution control technologies. These investments are partially offset in some scenarios by a decrease in the allowance burden associated with tradable emissions allowances, leading the effect on electricity price to be somewhat less than it otherwise would be. The combined effects contribute to a 1 percent increase in retail electricity prices and a decrease in producer profits of about $3 billion to $5 billion in 2020 under the policy scenarios we examine. Over the modeling horizon, whether MATS is implemented independently or alongside CSAPR, consumers pay for about 70 percent of the costs associated with the regulations, and producers pay the other 30 percent. In 2020, for example, total annual costs are $7.1 billion under MATS and $6.6 billion under CSAPR and MATS. These impacts vary by region; all the producer impacts are incurred in competitive regions because we assume full cost recovery in regions with cost-of-service regulation. The investment in pollution controls also leads to environmental benefits, including substantial reductions in emissions of mercury and SO_2.

2. Prior Reliability Studies of New Environmental Regulations

The EPA is in the process of developing or issuing several new regulations focused on electricity generators (which are briefly described in Box 1). Three of these regulations focus on atmospheric emissions. CSAPR focuses on SO_2 and NO_x emissions, and MATS focuses on mercury and other air toxics. The New Source Performance Standards issued in draft form in March address carbon dioxide (CO_2) from new fossil steam plants; additional regulations affecting existing sources are expected in the future. New regulations also are also being developed for solid wastes associated with coal combustion and for the intake of cooling water at thermal power plants. Compliance with these regulations will impose costs on the power sector; several of the regulations related to air emissions will be of particular concern for coal-fired plants. The coincident timing of the deadlines for compliance under several of these regulations have raised concerns among industry participants and observers that the regulations could have adverse effects on the reliability of electricity supply in the short run. For example, some suggest the relatively short compliance deadlines for these regulations could lead facilities to schedule outages to install control equipment, a circumstance that could impose supply disruptions if multiple generators are off-line simultaneously. There is the additional concern that the deadlines will be tough to meet due to time requirements for permitting, design, and construction, suggesting that this short-term crunch may be at its worst and occur shortly before the compliance deadlines. Further, the expectation of high compliance costs has raised concerns about the reliability of an ample supply of generation capacity in the long run. The concern is that a number of older existing generators, particularly smaller ones without SO_2 flue gas desulfurization scrubbers, may choose to retire instead of installing controls and that this increased rate of retirement would pose a threat to reliability.

Numerous studies over the last two years look at the effects of some or all of these regulations on the electricity sector. The studies reviewed for this paper are listed in Table 1, which notes when they were published, what regulations they reviewed, whether they used an equilibrium model, and how they measured reliability. The studies focus on a number of factors, including compliance costs, coal-fired generator retirements, reliability impacts, and the amount of investment in retrofit pollution controls existing generators will need to comply with regulations. Several studies discuss the expected impact of the regulations on electricity prices. A few studies also discuss the scheduling of regulatory compliance and the amount of time required to make investments necessary to come into compliance. Some studies focus on a specific regulation, while most of the studies focus on collections of regulations. Most of these studies were published before the final versions of CSAPR and MATS were issued and thus those that focus on these regulations actually focus on EPA's initially proposed Clean Air Transport Rule, which was modified in the final rule as described in Box 1, and anticipated versions of MATS.

These studies draw a wide range of conclusions about the effects of these EPA regulations on the electricity sector. The conclusions depend importantly on several features of the studies, including how the studies interpret regulation requirements and compliance schedules; what they assume about the technologies available to firms for compliance; what methodology they use (in particular, whether they use an equilibrium model that will determine the effect on prices and revenues for existing plants); and which sets of regulations they include in the analysis. The studies also differ in the extent to which they address the question of likely impacts of regulation on reliability and, when it is addressed, how reliability is defined. Each of these issues is addressed in the following paragraphs.

Stringency of Regulation: Studies by the Bipartisan Policy Center (Macedonia et al. 2011) and the Congressional Research Service (CRS 2011) review a number of the prior analyses of various combinations of EPA regulations. Both reviews conclude that the studies that find regulatory compliance costs at the higher end of the spectrum or higher levels of expected capacity retirement tend to make aggressive assumptions about the requirements of the regulation. This happened in part because studies were conducted prior to the release of the regulations and thus analysts had to make assumptions about what the final regulations would look like. For example, in October 2010, the North American Electricity Reliability Corporation (NERC) released a reliability review based on potential impacts of EPA regulations. The report was written prior to the release of EPA's proposed regulation of cooling water intake under section 316(b) of the Clean Water Act (CWA). The NERC report assumes that all affected units would have to install expensive cooling towers. This assumption contributed to NERC's estimate that between 10 and 35 gigawatts (GW) of coal-fired capacity would retire by 2018 (NERC 2010). In a follow-up report issued after the release of EPA's proposed CWA rule, NERC reduced its retirement estimates to between 7.5 and 17.8 GW of coal-fired capacity by 2018. This decrease reflects, in part, the fact that EPA's proposed rule does not require all affected units to undergo expensive retrofits to comply (NERC 2011). Another study on behalf of the Edison Electric Institute (Fine et al. 2011) includes aggressive assumptions about future CO_2 prices, at

$10 and $25, beginning in 2018. Both of these assumptions are above the costs per ton expected under EPA's expected CO_2 regulations if modeled as an emissions cap and trade program.[1]

Range of Available Compliance Options: Some studies, including those by NERC (2010, 2011) and Charles Rivers Associates, performed by Shavel and Gibbs (2010), limit the compliance options available for the MATS rule to scrubbers and fabric filters or activated carbon injection. Others allow dry sorbent injection (DSI) to be part of the mix, although often with a size limit on the units that can install this technology (Macedonia et al. 2011, NERA 2011). None of the previous studies allow for endogenous investments to improve heat rates at existing facilities, which is especially important for complying with CO_2 regulations. In general, limiting compliance options tends to raise the cost of compliance and predictions of retirement.

Methodology/Use of Equilibrium Models: As noted in Table 1, most of the studies analyzed here use an equilibrium model to look at the effects of EPA regulations on the electricity sector. EPA (2011d, 2011e), the Bipartisan Policy Center (Macedonia et al. 2011), and the Edison Electric Institute (Fine et al. 2011) all use the Integrated Planning Model for their analyses. The Charles Rivers Associates study (Shavel and Gibbs 2010) uses the North American Electricity and Environment Model, and the Department of Energy (2011) and NERA (2011) studies use the National Energy Modeling System to model electricity and other energy market impacts. By using a market equilibrium model, these studies can capture the effects of regulations on equilibrium electricity prices in the future as well as their effects on investment in new generation technologies. However, there are exceptions, including the NERC analysis, which compares expected retrofit costs on a plant-by-plant basis with replacement costs but does not analyze the regulations in an equilibrium setting. These studies are unable to capture the electricity price responses to regulations that may tend to mute incentives for retirement as reductions in the supply of capacity available to meet reserve requirements will tend to raise the prices offered for capacity reserves. Higher prices for reserve services would raise the opportunity cost of retirement and change the economics of plant retrofit decisions.

[1] Burtraw et al. (2011) show that cap and trade policies sufficient to achieve emissions reductions of about 5 percent, commensurate with the U.S. Environmental Protection Agency's expected target for 2018, could be achieved with credit prices of allowance prices of $4. Some reductions are achieved by substitution away from coal to other fuels. Policies that more narrowly focused on heat rate improvements at existing plants and do not give credit for reduced utilization would incur costs commensurate with the Edison Electric Institute's estimates for emissions reductions up to 3 percent. The Edison Electric Institute's modeling does not include the opportunity for investments to improve operating efficiency at existing plants. These investments provide most of the emission reductions in Burtraw et al.

Specification of the Baseline: The costs (and benefits) of a new environmental regulation will depend importantly on what regulations are assumed to be in place in the baseline scenario against which the regulatory scenario is compared. EPA analysis features a staging of regulations. The regulatory impact analysis of CSAPR (EPA 2011e) does not include CAIR in the baseline, but the regulatory impact analysis of MATS (EPA 2011d) does include CSAPR in the baseline. Given that CSAPR was scheduled to take effect before MATS, putting CSAPR in the baseline for the analysis of the MATS rule makes sense. It is interesting to note that the EPA analysis of CSAPR appears to be the only one that excludes CAIR from its baseline. Given that many of the investments for compliance with CAIR have already been made, this probably does not have a big effect on costs, but it does have a big effect on the size of the emissions reductions and environmental benefits assigned to the policy, and hence the ratio of costs to benefits.

Table 1. Recent Studies of Environmental Regulations in the Electricity Sector

Study Sponsor	Citation	Date Released	Regulations Considered	Equilibrium Model	Reliability Measure
American Electric Power	Braine 2011	04/2011	CATR, MATS, CCR, CWA 316(b)	No	Transmission and Capacity
Bipartisan Policy Center	Macedonia et al. 2011	06/2011	CATR, MATS, CCR, CWA 316(b)	Yes	Transmission and Capacity
Charles River Associates	Shavel and Gibbs 2010	12/2010	CATR, MATS	Yes	Capacity
Congressional Research Service	CRS 2011	08/2011	CATR, MATS, CCR, CWA 316(b), NSPS for GHG, NAAQS, Clean Water Effluent Limitation Guidelines	No	Capacity
Credit Suisse	Not Cited	04/2011	CATR, MATS	No	No discussion
Department of Energy	DOE 2011	12/2011	CSAPR, MATS	Yes	Capacity
Edison Electric Institute	Fine et al. 2011	01/2011	CATR, MATS, CCR, CWA 316(b), CO_2 regulation	Yes	No discussion
EPA CCR RIA	Not Cited	04/2010	CCR	No	No discussion
EPA CSAPR RIA	EPA 2011e	06/2011	CSAPR	Yes	No discussion
EPA MATS RIA	EPA 2011d	12/2011	MATS	Yes	Capacity
FBR Capital Markets	Salisbury et al. 2010	12/2010	CATR, MATS, CCR, CWA 316(b)	No	Transmission and Capacity
ICF International	Not Cited	03/2011	CATR, MATS, CCR, CWA 316(b), CO_2 regulation	Yes	No discussion
ICF International	Rose et al. 2011	07/2011	CATR, MATS, CCR, CWA 316(b)*	Yes	Transmission and Capacity
M.J. Bradley & Assoc.	Not Cited	06/2011	CATR, MATS	No	Capacity
M.J. Bradley & Assoc.	Not Cited	11/2011	CSAPR, MATS	No	Capacity
NERA	NERA 2011	09/2011	CSAPR, MATS, CCR, CWA 316(b)	Yes	No discussion
NERC	NERC 2010	10/2010	CATR, MATS, CCR, CWA 316(b)	No	Capacity
NERC	NERC 2011	11/2011	CSAPR, MATS, CCR, CWA 316(b)	No	Capacity
Utility Air Regulatory Group	Not Cited	10/2010	CATR	No	No discussion

* ICF International refers to MATS by name but refers more generally to the "four proposed rules released by the EPA impacting the development and operations of coal-burning power plants." We assume those to be the Clean Air Transport Rule (CATR), Coal Combustion Residuals (CCR), and Clean Water Act (CWA) section 316 (b).

Definition of Reliability: Several of the studies do not focus specifically on the issue of reliability. Those studies that do discuss reliability explicitly (See Table 1) discuss the effects on coal plant retirements and on the ability to meet reserve margins, both nationally and at the NERC or sub-NERC region level. Though not a direct result of modeling, some studies discuss issues associated with the timing of regulatory requirements and the amount of time needed to install retrofits (Braine 2011 focuses on the latter). Some studies discuss both the longer-term issue of capacity reserve margins as well as shorter-term and location-specific concerns about grid support or local transmission security and how the regulations might affect supply of services such as voltage support and frequency regulation (Salisbury et al. 2010; Braine 2011).

A better way to frame this debate over reliability might be in terms of cost and the extent to which these regulations will lead to higher costs of delivering the ancillary services needed to keep the grid operating in a reliable fashion in a particular location. Retirement of coal-fired units in certain locations could have important implications for the functioning of particular transmission lines or sections of the grid, but options are available to meet those needs. However, they come at a cost, and analyzing the cost of those options requires a different type of model and analysis than that which is typically used for generation capacity planning and regulatory impact analysis of EPA rules. Nonetheless, this type of analysis, known as transmission security analysis, is widely practiced in the industry and can be used to help identify potential disruptions to grid performance at the local level and to identify options for ensuring grid reliability (Rose et al. 2011). Ancillary services are increasingly traded and priced in markets established by regional grid operators, and these markets can provide a price signal that will create incentives for others, including both supply and, in some cases, demand resources to step in and fill a void left by a retiring generation facility.

In the end, concerns about the effects of these regulations on the reliability of electricity supply are likely misplaced. The fact that electricity is traded in markets means that actual or anticipated reductions in supply will be translated into increased prices, and these higher prices in turn will induce more investment in capacity and greater supply. EPA regulatory policies will have an effect on the market price of electricity and thus may impinge on the reliability of low electricity prices that consumers have enjoyed. However, as discussed in the results section for our simulation analysis below, we did not find substantial price increases between 2013 and 2035. There may be more relevant scheduling problems in the short run as facilities jockey to schedule investments necessary to attain compliance and tie in control equipment, but as noted this is not explicitly addressed in any of the analyses reviewed in Table 1.

Box 1. New and Pending Regulations Affecting Power Plants

<u>Rules modeled in this analysis:</u>

The Cross-State Air Pollution Rule

The U.S. Environmental Protection Agency (EPA) finalized its Cross-State Air Pollution Rule (CSAPR) on July 6, 2011. However, the rule is undergoing legal challenge. In December 2011, the U.S. Court of Appeals for the D.C. Circuit stayed CSAPR pending judicial review. The rule would replace the 2005 Clean Air Interstate Rule (CAIR), which was vacated by the Court of Appeals and remanded to the EPA. Under CSAPR, electricity generating units in 28 states in the eastern half of the country are required to significantly reduce air pollution that crosses state lines, including annual sulfur dioxide (SO_2) emissions, annual nitrogen oxide (NO_x) emissions, and ozone-season NO_x emissions. The first phase of compliance would have begun in January 2012. A second phase of SO_2 reductions is scheduled to begin in 2014. CSAPR allows unlimited intrastate trading of pollution credits between power plants and limited interstate trading. In contrast to the originally proposed Clean Air Transport Rule (CATR), the final rule impacts fewer states and modifies the allowance allocation rules.

Mercury and Air Toxics Standards

On December 21, 2011, the EPA finalized its Mercury Air Toxics Standards (MATS) for power plants. The rule requires new and existing coal- and oil-fired units to reduce emissions of heavy metals, including mercury, arsenic, chromium, and nickel, and of acid gases, such as hydrogen chloride and hydrogen fluoride. The rule allows for power plants to use a range of technologies to meet the standards, including wet and dry scrubbers, dry sorbent injection systems, activated carbon injection systems, and fabric filters. Existing sources must comply within three years; however, sources can obtain an additional year from state permitting authorities if needed to complete retrofits. As a result, most plants will have until 2016 to comply. In addition, units that play an important reliability role can apply for an administrative order to obtain an additional year to obtain compliance.

<u>Other new or pending rules not modeled:</u>

The Coal Combustion Residuals Rule

On June 21, 2010, the EPA proposed a new rule to regulate coal combustion residuals, or coal ash, produced from power plants. The rule considers regulation under subtitle C or subtitle D of the Resource Conservation and Recovery Act.

The Clean Water Act Section 316(b) Rule

The EPA proposed a new rule on March 28, 2011, to regulate cooling-water intake safeguards under section 316(b) of the Clean Water Act. The agency is under a court-ordered deadline to issue a final rule by July 27, 2012. The proposed rule would affect existing power plants and manufacturing facilities that withdraw at least 2 million gallons of cooling water per day.

Greenhouse Gas Performance Standards

On March 27, 2012, the EPA issued a proposed rule to regulate carbon dioxide emissions from new fossil fuel-fired generating units. The New Source Performance Standard requires affected units to emit no more than 1,000 pounds of carbon dioxide per megawatt-hour. Units can meet the standard over the course of either one year or using a 30-year averaging period. Most natural gas plants can meet this standard without installing new pollution controls. However, new coal plants will have to utilize carbon capture and sequestration to comply. The EPA is also expected to issue a rule to regulated greenhouse gas emissions from existing sources, but the timing for that new rule is still uncertain.

3. Modeling Strategy

We use a highly parameterized electricity market simulation model to characterize the response of the electricity system to two new and likely most important environmental regulations, CSAPR and MATS.

3.1 The Haiku Electricity Market Model

The simulation modeling uses the Haiku electricity market model, which solves for investment and operation of the electricity system in 22 linked regions in the continental United States, starting in 2013 out to the year 2035. Each simulation year is represented by three seasons (spring and fall are combined) and four times of day. For each time block, demand is modeled for three customer classes (residential, industrial, and commercial) in a partial adjustment framework that captures the dynamics of the long-run demand responses to short-run price changes. Supply is represented using 58 model plants in each region. Thirty-nine of the model plants aggregate existing capacity according to technology and fuel source from the complete set of commercial electricity generation plants in the country. The remaining 19 model plants represent new capacity investments, again differentiated by technology and fuel source. Each coal model plant has a range of capacity at various heat rates, representing the range of average heat rates at the underlying constituent plants.

Operation of the electricity system (generator dispatch) in the model is based on the minimization of short-run variable costs of generation and a reserve margin is enforced based on margins obtained by the Energy Information Administration in the Annual Energy Outlook (AEO) for 2011 (EIA 2011). Fuel prices are benchmarked to the AEO 2011 forecasts for both level and supply elasticity. Coal is differentiated along several dimensions, including fuel quality and content and location of supply, and both coal and natural gas prices are differentiated by point of delivery. The price of biomass fuel also varies by region depending on the mix of biomass types available and delivery costs. All fuels are modeled with price-responsive supply curves. Prices for nuclear fuel and oil as well as the price of capital and labor are held constant.

Investment in new generation capacity and the retirement of existing facilities are determined endogenously for an intertemporally consistent (forward-looking) equilibrium, based on the capacity-related costs of providing service in the present and into the future (going-forward costs) and the discounted value of going-forward revenue streams. Unlike previous studies, existing coal-fired facilities also have the opportunity to make endogenous investments to improve their efficiency. Discounting for new capacity investments is based on an assumed real cost of capital of 7.5 percent. Investment and operation include pollution control decisions to comply with regulatory constraints for SO_2, NO_x, mercury, hydrochloric acid (HCl), and particulate matter (PM), including equilibria in emissions allowance markets where relevant. All currently available generation technologies as identified in AEO 2011 are represented in the model, as are integrated gasification combined cycle coal plants with carbon capture and storage and natural gas combined cycle plants with carbon capture and storage. Ultra-supercritical pulverized coal plants and carbon capture and storage retrofits at existing facilities are not available in the model.

Price formation is determined by cost-of-service regulation or by competition in different regions corresponding to current regulatory practice. Electricity markets are assumed to maintain their current regulatory status throughout the modeling horizon; that is, regions that have already moved to competitive pricing continue that practice, and those that have not made that move remain regulated.[2] The retail price of electricity does not vary by time of day in any region, though all customers in competitive regions face prices that vary from season to season.

An important part of the model is the requirement that each region have sufficient capacity reserve to meet requirements drawn from the North American Electric Reliability Corporation. The reserve price reflects the scarcity value of capacity and is set just high enough to retain just enough capacity to cover the required reserve margin in each time block. The model does not model separate markets for spinning reserves and capacity reserves. Instead, the fraction of reserve services provided by steam generators is constrained to be no greater than 50 percent of the total reserve requirement in each time block.

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[2] There is currently little momentum in any part of the country for electricity market regulatory restructuring. Some of the regions that have already implemented competitive markets are considering reregulating, and those that never instituted these markets are no longer considering doing so.

3.2 Technology and Compliance Options

The Haiku model includes endogenous compliance with environmental regulations. Available strategies include investment in pollution control and, as appropriate, the use of emissions allowances as well as the choice of fuel and coal type. Table 2 lists the current set of pollution controls modeled in Haiku. These technologies are all available at existing coal plants in combinations we discuss below. New coal steam plants are assumed to install wet flue gas desulfurization (FGD), selective catalytic reduction (SCR), and fabric filters. Existing gas and oil steam plants have the option of installing SCR if it is not already in use. New gas steam plants are assumed to be combined cycle with SCR. The model does not allow the construction of new oil plants.

Table 2. Pollution Abatement Control Technologies Modeled in Haiku

Control Technology	Acronym	Primary Pollutants Abated
Selective Catalytic Reduction	SCR	NO_x
Selective Noncatalytic Reduction	SNCR	NO_x
Wet Flue Gas Desulfurization	Wet FGD	SO_2 and HCl
Dry Flue Gas Desulfurization	Dry FGD	SO_2 and HCl
Dry Sorbent Injection	DSI	SO_2 and HCl
Activated Carbon Injection	ACI	Mercury
Fabric Filters	FF	Particulate Matter
Electrostatic Precipitator	ESP	Particulate Matter

Many but not all feasible combinations of pollution controls at coal plants are modeled in Haiku. For example, the combination of wet FGD and SCR provides sufficient mercury removal to meet national and state-level mercury abatement requirements, so the set of wet FGD, SCR, and activated carbon injection (ACI) is not considered. From the set of possible pollution control combinations, the algorithm endogenously selects the set of pollution abatement controls for each model plant that minimizes the present discounted value of control costs, including any allowance or emissions tax costs, over the modeling horizon. For coal plants, the model also simultaneously selects the type of coal that minimizes these costs. Table 3 shows all possible combinations of pollution controls that are modeled in Haiku for an existing steam coal model plant.

Table 3. Possible Combinations of Pollution Abatement Technologies in Haiku Models

NO_x Controls	SO_2/HCl Controls	Mercury Controls	PM Controls[3]
SCR	None	None or ACI	None, FF, ESP, or FF + ESP
SCR	Wet FGD	None	None, FF, ESP, or FF + ESP
SCR	Dry FGD	None or ACI	None, FF, ESP, or FF + ESP
SCR	DSI	None or ACI	FF, ESP, or FF + ESP
SNCR	None	None or ACI	None, FF, ESP, or FF + ESP
SNCR	Wet FGD	None or ACI	None, FF, ESP, or FF + ESP
SNCR	Dry FGD	None or ACI	None, FF, ESP, or FF + ESP
SNCR	DSI	None or ACI	FF, ESP, or FF + ESP
None	None	None or ACI	None, FF, ESP, or FF + ESP
None	Wet FGD	None or ACI	None, FF, ESP, or FF + ESP
None	Dry FGD	None or ACI	None, FF, ESP, or FF + ESP
None	DSI	None or ACI	FF, ESP, or FF + ESP

The one exception to the cost-minimizing approach to selecting pollution controls is controls for particulate matter, which are specified exogenously for the MATS policy. This includes both new fabric filters and upgrades to existing electrostatic precipitators (ESP). The model assumes that no new ESP will be installed. Coal boilers were selected to install a fabric filter or invest in one of three levels of ESP upgrades based on the list of boilers that installed these controls in EPA's analysis of MATS (EPA 2011a).

The technical specification and cost of controls are drawn from Sargent & Lundy (2010a, 2010b, 2010c, 2010d, 2010e, 2011a, 2011b), EPA (2006, 2010) and EPA's National Electric Energy Data System v.4.10. Additional information on the pollution controls and how they are modeled is presented in Appendix 1.

[3] Activated carbon injection (ACI) systems require an electrostatic precipitator or small fabric filter to capture the activated carbon in the flue gas. However, we assume this additional control is part of the ACI system and does not provide any additional particulate matter (PM) capture, so it is not considered a PM control technology.

Haiku's technology assumptions differ from and expand on those in other recent studies. For example, Haiku allows coal units to endogenously select DSI to comply with SO_2 or HCl limits under MATS as long as the unit burns low-sulfur fuel and has a capacity of 25 megawatts (MW) or larger. The removal efficiency of the DSI system varies depending on the presence of an ESP or fabric filter. These assumptions mirror those used by EPA in its final MATS analysis. However, other recent studies make different assumptions for DSI. For example, NERA (2011) and a study by the Bipartisan Policy Center (Macedonia et al. 2011) assume all units smaller than 300 MW that do not have a scrubber and burn low-sulfur coal can install DSI and a fabric filter and that larger units cannot. Another study by Fine et al. (2011) assumes in its primary scenarios that no DSI will be installed. However, in a sensitivity case, the study allows units that are 200 MW or less to install DSI. Other controls, such as FGD and ACI, are endogenously selected in the Haiku model for existing coal plants that do not currently have these controls. This differs from several other recent studies. For example, NERC (2010) assumes that all coal units that do not have a scrubber will install a wet scrubber and that all coal units burning bituminous coal will install SCR. Alternatively, a study by Charles River Associates (Shavel and Gibbs 2010) assumes all coal units will install ACI, fabric filters, and wet scrubbers.

4. Scenarios

The impacts of MATS and CSAPR are compared to a baseline scenario, which we describe below.

4.1 Baseline

The baseline (no new regulation) scenario includes prior environmental regulations, such as emissions limits set under Title IV and CAIR, the predecessor to CSAPR. Title IV governs nationwide SO_2 emissions, setting the national level constraint of 8.95 million emissions allowances annually. One allowance under Title IV is valued at one ton, and allowances are bankable. CAIR altered this constraint in important ways for plants in the eastern states composing the largest share of total national emissions. It changed the value of an emissions allowance for those emissions in that region with vintage 2010 or later, requiring two allowances per ton in 2010 and increasing over time. Facilities outside the CAIR region would continue to operate under the Title IV constraint. CAIR also imposed annual and summertime emissions caps on NO_x in a similar but not identical group of states.

In the baseline, plants located in states with state-level mercury regulations must comply with these standards as well. Electricity demand and fuel prices, including natural gas prices, come from AEO 2011. Prior work (Burtraw et al. 2012) shows that projections of electricity demand as well as natural gas supply and prices, which have varied substantially between recent releases of the Energy Information Administration's AEO, can have a large impact on anticipated market outcomes in the electricity sector. The authors find that the difference between the 2009 and the 2011 forecasts of secular changes in natural gas prices and electricity demand have a larger impact on future electricity prices and fuel mix than does the introduction of CSAPR and MATS regulations.

4.2 CSAPR and MATS

The two policy scenarios analyzed are referred to as MATS and CSAPR & MATS. The MATS scenario is identical to the baseline, including the presence of CAIR and state-level mercury standards, except the MATS regulation is also assumed to be in effect. MATS is intended to reduce emissions from new and existing coal and oil-fired power plants of heavy metals, such as mercury, arsenic, chromium, and nickel, as well the emissions of acid gases, such as hydrochloric acid and hydrofluoric acid. In its final regulatory impact analysis, EPA projects that the rule will results in annual monetized benefits in 2007$ of between $37 billion and $90 billion, assuming a 3 percent discount rate. A large portion of the estimate comes from the reduction of fine particulate matter, a co-benefit (EPA 2011d). For more information on how MATS is modeled, see Appendix 2.

In the CSAPR & MATS scenario, MATS is once again assumed to be in effect, and CSAPR replaces CAIR. CSAPR is intended to reduce SO_2 and NO_x emissions that cross state lines and contribute to nonattainment of pollution standards in states downwind. In total, 27 states in the eastern part of the United States are required to comply. Affected states are required to either reduce annual NO_x emissions or reduce ozone season NO_x emissions. States are also broken into two groups for SO_2 requirements, with one group of states subject to more stringent reductions than the other. Haiku's model regions do not perfectly align with CSAPR's state-level requirements. As a result, adjustments were made to Haiku regions and model plants that spanned the policy zone to closely approximate the impact of the policy. To meet the standards, CSAPR allows for intrastate trading of emission allowances and limited interstate trading. The Haiku model approximates this requirement by allowing for trading within regions affected by the policy. Outside the CSAPR region, Title IV standards remain in effect for SO_2, but SO_2 prices are expected to fall to zero. When the rule was finalized, the EPA estimated that by 2014, CSAPR would lower SO_2 emissions by 6.4 million tons per year and NO_x emissions by 1.4

million tons per year, as compared to 2005 (EPA 2011c). As in the baseline, both scenarios assume AEO 2011 electricity consumption and natural gas prices.

In the simulations, CSAPR is implemented in 2012, with stringency increasing in 2014. MATS is assumed to be fully implemented in 2016. In reality, MATS takes effect in 2015. However, as discussed above, the EPA has stated that most plants will be given a one-year extension to comply. The agency expects a small number of plants to apply for, and receive, an additional year extension, pushing compliance out to 2017. The first phase of compliance with CSAPR was scheduled to begin on January 1, 2012, with more stringent requirements beginning in 2014. However, as mentioned in Box 1, implementation was halted by the courts while the rule undergoes legal review.

5. Key Indicators of Change

In this section we report key indicators of the effects of new environmental regulations on expected reliability of electricity supply and other measures of performance.

5.1 Capacity & Generation Results

A key measure of reliability is electricity supply, which we assess by analyzing the impacts of the regulations on electricity capacity and generation, both in the midterm, 2020, and in the long term, 2035. As seen in Table 4, neither the MATS scenario nor the CSPAR & MATS scenario leads to substantial changes in existing capacity by 2020 compared to the baseline. This includes coal capacity, which falls about 1.2–1.5 percent under the policy scenarios. Natural gas capacity remains virtually unchanged under MATS and under CSAPR & MATS from baseline. There are, however, reductions in new capacity in 2020, mostly due to lower investment in new natural gas plants.

In the long run, the policies still will have little impact on national capacity. In 2035, total existing capacity remains virtually the same under the two policies compared to baseline. There are small decreases in coal capacity of about 1.5 percent and small increases in natural gas capacity, ranging from about 1 percent under MATS to about 2 percent under CSAPR & MATS. Total new capacity is 1.2 percent lower under CSAPR & MATS than under the baseline.

Table 4. Capacity Effects for Nation (GW)

	Baseline	MATS	CSAPR & MATS
2020			
Total Coal	333	329	328
Percent Difference		*-1.2%*	*-1.5%*
Total Natural Gas	391	390	393
Percent Difference		*-0.3%*	*0.5%*
Existing	955	957	958
Percent Difference		*0.2%*	*0.3%*
Cumulative New	112	106	102
Percent Difference		*-5.4%*	*-8.9%*
Total	1,067	1,063	1,061
Percent Difference		*-0.4%*	*-0.6%*
2035			
Total Coal	334	329	329
Percent Difference		*-1.5%*	*-1.5%*
Total Natural Gas	499	504	509
Percent Difference		*1.0%*	*2.0%*
Existing	954	956	958
Percent Difference		*0.2%*	*0.4%*
Cumulative New	244	244	241
Percent Difference		*0%*	*-1.2%*
Total	1,199	1,200	1,199
Percent Difference		*0.1%*	*0%*

There are also relatively small changes in national generation between the baseline and policy scenarios. As shown in Table 5, total generation in 2020 is less than 1 percent below the baseline under both policy scenarios, commensurate with the small effect that these policies have on electricity demand. This aggregate change is comprised of small decreases in coal generation under MATS as well as decreases in natural gas generation under both policy scenarios. In 2035 total generation falls by just under 1 percent under both policy scenarios. Coal generation decreases about 1 percent under MATS and 3 percent under CSAPR & MATS. Natural gas generation falls about 1.1 percent under MATS but rises by 1.5 percent under CSAPR & MATS.

Table 5. Generation Effects for Nation (TWh)

Year 2020	**Baseline**	**MATS**	**CSAPR & MATS**
2020			
Coal	1,836	1,809	1,836
Percent Difference		*-1.5%*	*0%*
Natural Gas	836	824	786
Percent Difference		*-1.4%*	*-6.0%*
Total	4,200	4,168	4,173
Percent Difference		*-0.8%*	*-0.6%*
2035			
Coal	2,075	2,053	2,010
Percent Difference		*-1.1%*	*-3.1%*
Natural Gas	971	960	986
Percent Difference		*-1.1%*	*1.5%*
Total	4,579	4,542	4,546
Percent Difference		*-0.8%*	*-0.7%*

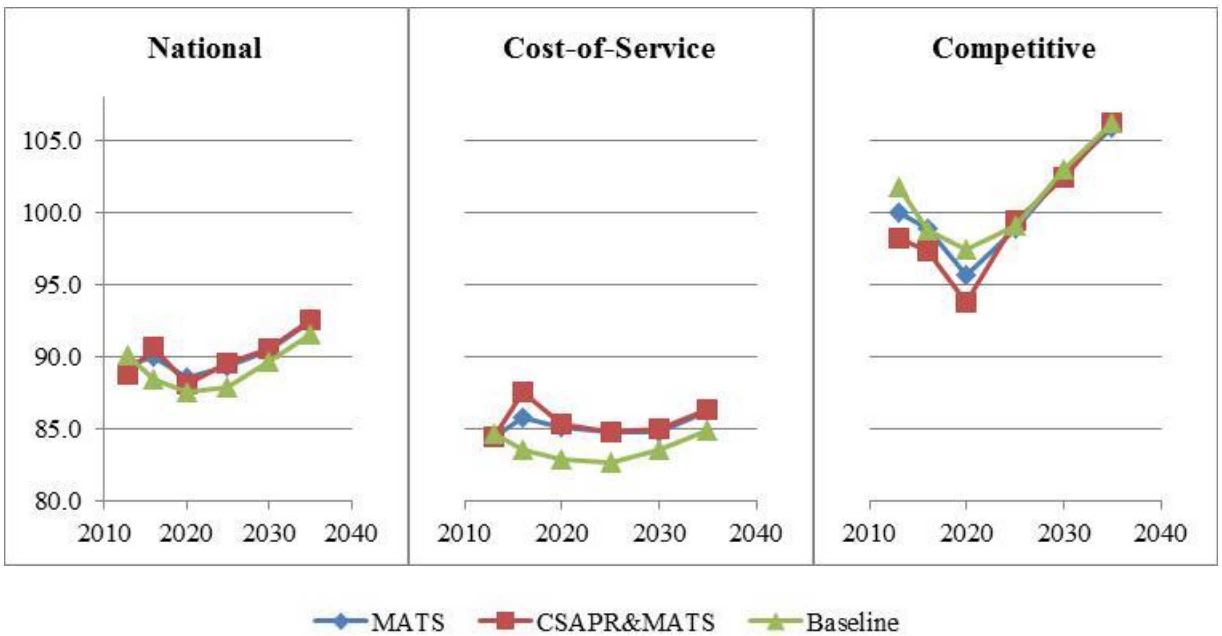
5.2 Price Changes for Generation and Reserve Supply

A key measure of the impacts of regulation is its effect on retail electricity prices. Figure 1 shows that MATS would have only a small effect on national average prices, causing them to rise by about 1 percent throughout the modeling horizon. CSAPR has virtually no effect on national average prices beyond the effects from MATS. These national averages obscure small regional differences that follow from the regulatory regime governing electricity pricing.

In regions of the country that price electricity in competitive markets, CSAPR and MATS have no effect on electricity prices in the long run and decrease prices slightly in the short run. The primary driver of these effects is the price for Title IV SO_2 allowances, which declines under MATS. This reduction in generation costs is sufficient at the margin to offset the cost of MATS compliance. In the short run, it is slightly more than sufficient, yielding a small price decline. Further discussion of allowance prices follows in section 5.5.

In cost-of-service regulated regions, electricity prices increase modestly under MATS over the entire simulation horizon and are affected little by the addition of CSAPR. The increase in 2020 in these regions averages about 2.5 percent from $83 per megawatt-hour (MWh) in the baseline to $85/MWh under both MATS and CSAPR & MATS. (All values are in constant 2009$.) In 2035 the change is about 1.2 percent from $85/MWh in the baseline to $86/MWh. In addition to a different technology mix, one distinction between the regions is the role of allowance cost in determining electricity prices. Allowances under Title IV (CAIR) and CSAPR are grandfathered, meaning they are distributed for free to incumbent firms. In cost-of-service regions only allowance purchases beyond their free allocation are passed along to their consumers via their rate base.

Figure 1. Regional Price Effects (2009$/MWh)



Another key price-based indicator of reliability of electricity supply is the reserve price paid to generators who bid into capacity markets to satisfy the need for a capacity reserve margin. National average reserve prices never change by more than 1 percent in any year under either policy scenario. This consistency indicates that national average supply reliability is largely unaffected by the policies.[4]

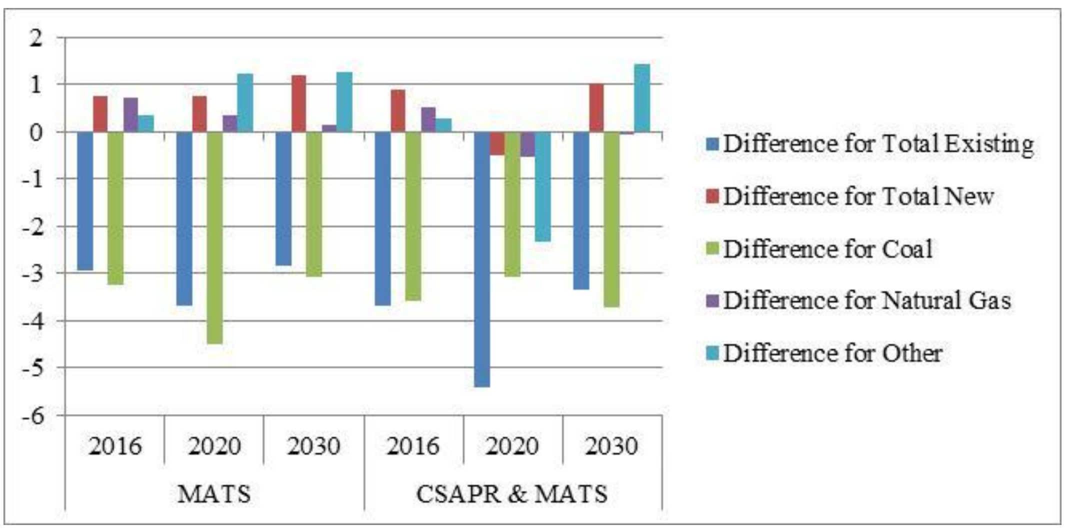
[4] As noted in the discussion on retail prices, reserve prices under the policy scenarios do vary from the baseline in some regions in some years. This is particularly true in regions with competive electricity markets.

5.3 Producer Surplus

Although these policies do not lead to supply shortages or large price increases for electricity customers, the regulations are not without cost. One measure of this cost is the change in producer surplus, which is defined as revenues minus costs and, when expressed in net present value terms, can be interpreted as a rough measure of asset value. Figure 2 shows changes in national producer surplus compared to the baseline aggregated for new and existing capacity and for various technologies. The figure highlights the decrease of about $3 billion to $5 billion in annual producer surplus under the policy scenarios for existing generating facilities. This decrease is driven largely by reductions in producer surplus from existing coal-generating facilities.

Throughout the time period, producer surplus increases slightly for new generation. The one exception is in 2020 under the CSAPR & MATS scenario, when all producer surplus is negative relative to the baseline. Natural gas generators see slightly positive changes in producer surplus under MATS. This trend is driven by increased producer surplus for existing, rather than new, capacity. The results are more mixed for natural gas producers under the CSAPR & MATS scenario. Finally, producer surplus for other types of generation, such as nuclear and wind, follow a similar pattern to natural gas.

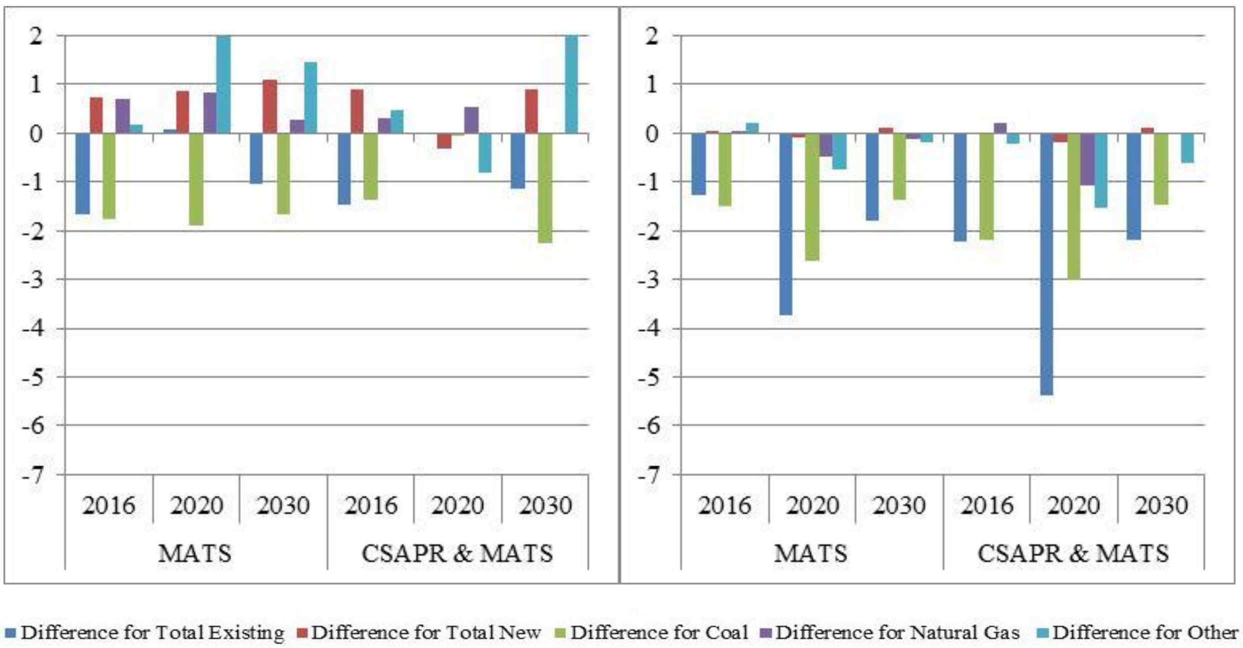
Figure 2. National Producer Surplus (Billion 2009$)



As shown in Figures 3 and 4, the national trend of decreasing producer surplus for existing generation, specifically coal, is driven largely by producers in the competitive regions. As with the price increases discussed above, the relatively large decreases in the competitive region reflects the inability of these producers to pass along fixed costs to consumers. In contrast, in the cost-of-service region, new fixed costs can be included in the rate base, and the losses of producer surplus associated with a specific technology are smaller. Similarly, the national trend of increasing producer surplus for new generation, natural gas, and other generation is attributed to increases in the cost-of-service regions. It is important to note that while the figure below shows producer surplus in the cost-of-service region relative to the baseline, total producer surplus in this group of regions is zero by construction.

Figure 3. Cost-of-Service Producer Surplus (Billion 2009$)

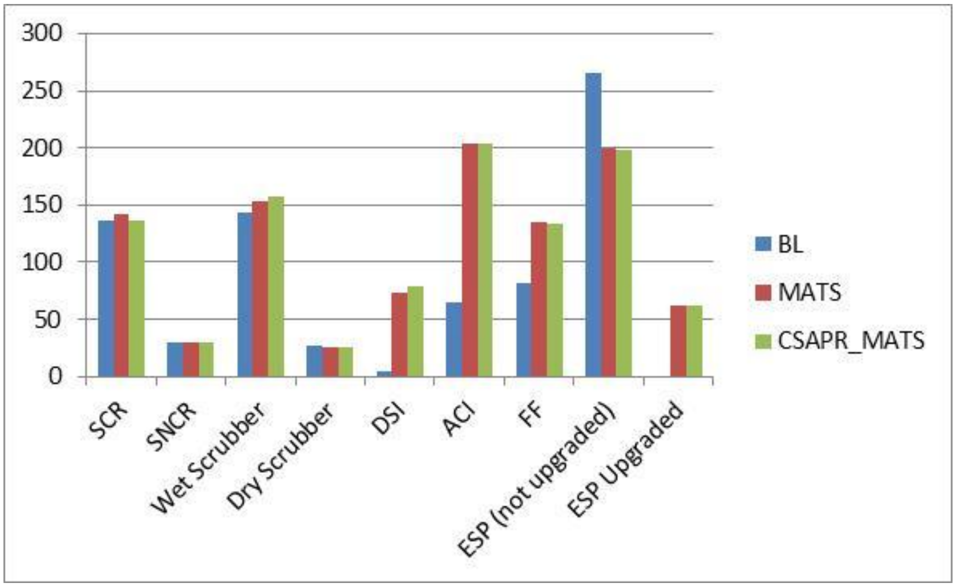
Figure 4. Competitive Producer Surplus (Billion 2009$)



5.4 Investments in Pollution Control

From a regulatory perspective, a key indicator of performance should be cost of compliance. The policy design will influence the choice of compliance options and costs incurred by consumers and producers. MATS and CSAPR are intended to reduce emissions of NO_x, SO_2, mercury, and other air pollutants. These pollutants are reduced in several ways, including the installation of post-combustion pollution controls. Figure 5 shows the amount of capacity nationwide that is predicted to install pollution controls in 2020 under the baseline and policy scenarios.

Figure 5. Pollution Controls in 2020 (GW)



By 2020, there is a more than tenfold increase in the installation of DSI, starting from 5 GW in the baseline and growing to 73 GW in the MATS scenario and 93 in the CSAPR & MATS scenario. There are also 200 percent increases in ACI, which rises from 65 GW in the baseline to between 203 GW and 204 GW in the MATS and CSAPR & MATS scenarios, respectively. There are also substantial changes in particulate matter controls, which are imposed exogenously in the model for compliance with MATS. The total amount of installed fabric filters increases from 82 GW in the baseline to 135 GW under MATS and 134 under CSAPR & MATS, with about 50 GW of the new fabric filters paired with ESP in both scenarios. The total amount of ESP remains unchanged, although about 62 GW of ESP are upgraded in both policy scenarios. The upgraded ESP has the ability to capture more particulate matter. Finally, there is a small increase in wet scrubbers under the policy scenarios, rising by 7 percent over baseline in the MATS scenario and by about 10 percent in the CSAPR & MATS scenario. These increases in particulate matter controls, ACI, and DSI are brought on by compliance with MATS, with some additional DSI stemming from compliance with CSAPR.

In the long run, MATS and CSAPR continue to spur investment in DSI and ACI. In addition, a substantial amount of DSI is built under the baseline scenario. By 2035, there is about 41 GW of DSI in the baseline, about 78 GW under the MATS scenario, and about 96 GW under the CSAPR & MATS scenario. Almost all new ACI investment, however, is driven by the policies. The MATS and CSAPR & MATS scenarios lead to an increase of ACI of about 213 percent compared to the baseline in 2035. The trend for wet scrubbers is less clear. In the MATS scenario, there is a decrease of 0.8 percent; in the CSAPR & MATS scenario, wet scrubbers increase by about 2 percent. The largest change, however, comes from SCR. While SCR investments increased slightly under the policy scenarios in 2020, the amount of capacity with the control technology falls in 2035 compared to the baseline. There is about 169 GW of SCR in the baseline in 2035, falling 5.9 percent under MATS to about 159 GW and falling about 16 percent under CSAPR & MATS to 142 GW. Some of this decrease is likely the result of plants installing more ACI for mercury control to comply with MATS instead of installing SCR and wet scrubbers, which yields similar mercury removal.

As discussed above, some recent studies of the CSAPR and MATS policies do not allow larger units to install DSI to reduce SO_2 or HCl. DSI has lower fixed costs than either of its substitutes, dry and wet scrubbers, but it also has greater variable costs and is less effective at reducing SO_2 emissions. To test for the sensitivity of our results to the assumption that DSI can be endogenously selected by any plant larger than 25 MW that burns low-sulfur fuel, we ran a MATS model that does not allow for any DSI.

When DSI is unavailable as a control strategy, roughly 1.0 percent of electricity generation shifts from coal generation to natural gas generation in the long run, and generating capacity and retail electricity prices are virtually unchanged throughout the modeling time horizon, as compared to the MATS scenario with DSI. Without DSI, the most significant change is that coal plants increase installations of the other two SO_2 pollution controls, wet and dry scrubbers. The capacity of wet scrubbers increases by about 6 GW, or 3.8 percent, as compared to the MATS scenario with DSI, and the capacity of dry scrubbers increases by about 38 GW, or 142 percent. The large increase in dry scrubbers reflects the likely substitution between DSI and dry scrubbers, since dry scrubbers are less costly than wet scrubbers.

The investments in new pollution controls are reflected in the total expenditures on control technologies. As shown in Table 6, and assuming the availability of DSI, incremental pollution control costs in 2020 total $5.1 billion under the MATS policy and $5.4 billion under CSAPR & MATS. This incremental investment constitutes a change in total investment in control technologies in coal plants of 30 percent under the MATS scenario and 32 percent under the CSAPR & MATS scenario. This increase is due primarily to greater spending on wet scrubbers, DSI, and ACI. In the long run, expenditures on pollution controls continue to be larger in the policy scenario as compared to the baseline. In 2035, total investment is about 20 percent higher under the MATS and CSAPR & MATS scenario as compared to the baseline in that year, due largely to increased spending on DSI and ACI.

Table 6. Coal Pollution Control Costs in 2020 (Billion 2009$)

Year 2020	**Baseline**	**MATS**	**CSAPR & MATS**
SCR	3.4	3.6	3.4
SNCR	0.2	0.2	0.2
Wet Scrubber	9.2	9.9	10.2
Dry Scrubber	1.9	1.8	1.8
DSI	0.1	1.3	1.4
ACI	1.3	4.3	4.4
Fabric Filter	1.0	1.0	1.0
Total	17.0	22.1	22.4

5.5 Allowance Cost

An interesting aspect of the program is the determination of prices for tradable emissions allowances. We find the introduction of prescriptive regulations with the MATS rule leads to technology choices that reduce the price of emissions allowances for those emissions regulated and traded under emissions caps. The allowance price changes mitigate electricity price increases from pollution control costs, contributing to the small changes in retail electricity prices described above.

Table 7. Allowance Prices (2009$/ton)

2020	**Baseline**	**MATS**	**CSAPR & MATS**
CAIR Annual NO_x	2,595	2,003	-
CAIR Seasonal NO_x	0	0	-
CSAPR Annual NO_x	-	-	0
CSAPR Seasonal NO_x	-	-	0
Title IV SO_2 (CAIR)	741	0	0
CSAPR SO_2 Middle Zone	-	-	977
CSAPR SO_2 Edge Zone	-	-	0

The CAIR NO_x programs are in effect in the baseline and under the MATS scenario. Table 7 reports that in 2020, the CAIR summertime seasonal program has allowance prices of zero in both cases. The CAIR annual program has substantial prices that fall under MATS due to ancillary reductions gained through achieving the MATS goals. In contrast, under CSAPR & MATS, both the seasonal and annual CSAPR NO_x programs have an allowance price of zero as a consequence of the investments in pollution controls made to comply with the entire regulatory package.

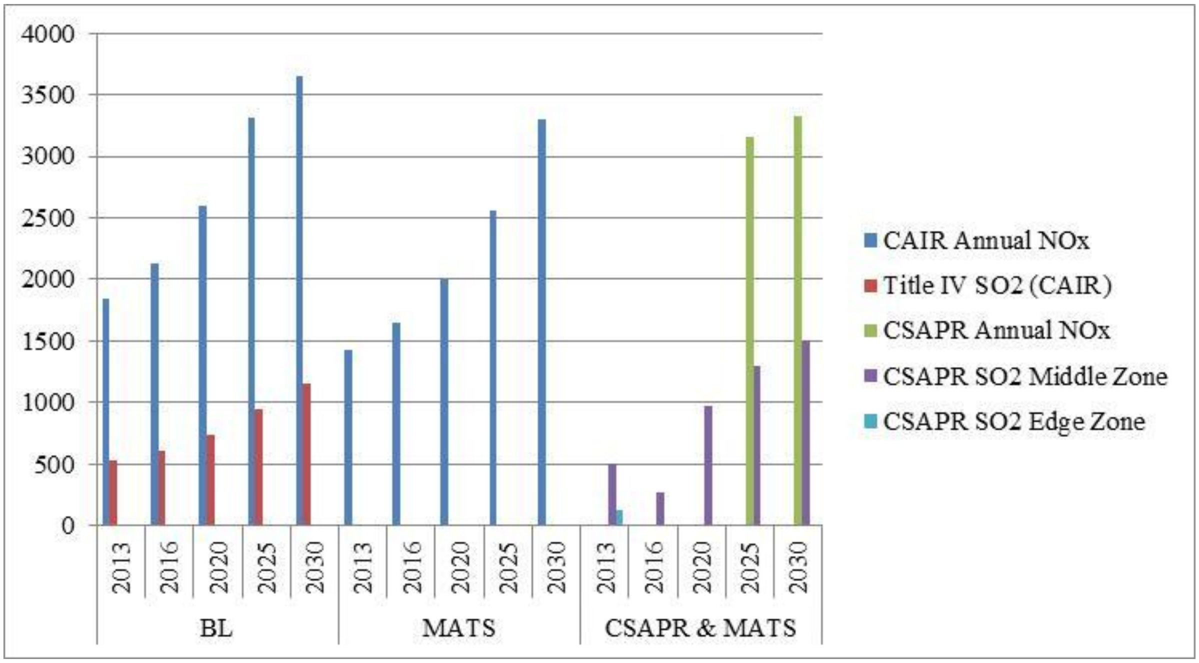
The Title IV SO_2 program is in effect in all scenarios, with more stringent standards for allowances required per ton within the CAIR SO_2 region than outside it in the baseline and MATS scenarios. This CAIR stringency is removed with the implementation of CSAPR. The MATS rule is projected to drive Title IV SO_2 allowance prices to zero. Under CSAPR & MATS, allowance prices in the SO_2 Middle Zone for CSAPR, which is similar to EPA's Group 1 states, are substantial, but they are zero in the SO_2 Edge Zone, which is similar to EPA's Group 2 states, and they are zero in the rest of the nation, which is still governed by the Title IV program.

The allowance burden as a portion of total costs can be substantial, so the differences that emerge across the scenarios have an effect on electricity prices. For example, in the baseline, 9.8 million Title IV allowances are required to cover the national SO_2 emissions in 2020. At a price of $741/ton, the allowance burden that year is $7.3 billion. Under MATS, the SO_2 allowance burden falls to zero. Under CSAPR & MATS, due to a positive price of $977/ton in the Middle Zone where emissions are 1.3 million tons, total SO_2 allowance burden is $1.3 billion. A similar calculation can be done for NO_x allowance costs. Under the baseline in 2020, the allowance burden adds up to $4.6 billion, compared to $3.5 billion under MATS, and $0 under CSAPR & MATS. In 2035, when the CSAPR annual NO_x price is no longer $0, the allowance burden under the baseline is $6.6 billion, as compared to $6.7 billion under the MATS scenario and $7.2 billion under the CSAPR & MATS scenario.

These substantial declines in allowance costs from the baseline offset some of the increase in investment cost of $5.1–$5.4 billion reported in Table 6, and they are an important component to the explanation of why electricity prices can be expected to rise less than some might have anticipated. The reduced compliance costs also affect the economic viability of existing generation capacity. Moreover, the impact will differ across regions. In cost-of-service regions, allowance costs will reflect original value. If they were initially received for free as happened under these trading programs, their value will not be included in electricity prices. However, in competitive regions, the allowance cost will be a component of the variable cost of generation and will be reflected in electricity prices even if allowances were received for free. Hence, when allowance prices fall, this has a downward influence on electricity prices and also on revenues available to the industry. Perhaps in an anticipated way, this decline in allowance costs may exacerbate the cost of the program for producers even as it reduces the costs for consumers.

These changes are illustrated in a useful way in Figure 6 for the entire simulation horizon. Annual NO_x allowance prices are greatest in the baseline, fall systematically under MATS and fall further in most years under CSAPR & MATS. (Note that allowance prices for the CAIR Ozone NO_x and CSAPR Ozone NO_x programs were not included in this figure because all prices were $0/ton throughout this timeframe.) Similarly, allowance prices for SO_2 are greatest in the baseline, fall to zero under MATS, and rise modestly in some years for parts of the country under CSAPR & MATS.

Figure 6. Allowance Prices (2009$/ton)



5.6 Environmental Performance

A central measure of the new regulations should be their environmental performance. The previously discussed increased investment in DSI and ACI under MATS is reflected in decreased emissions of SO_2 and mercury. Compared to the baseline, SO_2 emissions decrease by about 27 percent under the MATS scenario in 2020 and by about 34 percent under the CSAPR & MATS. Mercury emissions fall about 79 percent under both policy scenarios compared to the baseline.[5] Cumulative emissions of SO_2 follow a slightly different pattern of 12 percent reductions under MATS and 27 percent under CSAPR & MATS. Cumulative mercury emissions fall by 71 percent in both scenarios.

Reductions in NO_x and CO_2 emissions are less consistent. NO_x emissions decrease under the MATS scenario, but rise in 2020 under the CSAPR & MATS scenario, which assumes that CAIR is replaced by CSAPR. This difference is driven largely by the differences between the states covered by CAIR and the states covered by CSAPR. Delaware, Florida, Louisiana, Mississippi, and Washington, D.C., are all covered under the CAIR annual NO_x standards, but not under CSAPR. In contrast, Minnesota, Kansas, and Nebraska are covered by the CSAPR annual NO_x standards but not by CAIR. Cumulatively, NO_x emissions follow the 2020 pattern, with decreased NO_x emissions under the MATS scenario and increased emissions under the CSAPR & MATS scenario. The regulations do not target CO_2 emissions, and they are virtually unaffected, with small reductions in some years.

Table 8. Fossil Fuel Emissions

	Baseline	**MATS**	**CSAPR & MATS**
2020			
NO_x (thou. tons)	1,787	1,728	2,011
SO_2 (thou. tons)	3,545	2,581	2,348
CO_2 (mill. tons)	2,300	2,271	2,302
Mercury (thou. lbs.)	53.2	11.1	11.3
Cumulative 2013–2035			
NO_x (thou. tons)	41,206	40,911	46,299
SO_2 (thou. tons)	79,685	70,282	58,507
CO_2 (mill. tons)	54,871	54,285	54,261
Mercury (thou. lbs.)	1,235	363	357

[5] These are emissions from coal, oil, and natural gas-fired plants, not from the entire electricity sector.

6. The Potential for a Reliability Failure

As these results indicate, the reliability of the electricity system has several dimensions. We summarize the impacts of the new environmental regulations on each of these.

6.1 Reliability of Generation Capacity

Most discussions of reliability center on the concern about a disruption in electricity supply and specifically the possible inadequacy of generation capacity. However, this is in fact a fairly exotic concern. Historically, reliability problems in the United States are almost never caused by insufficient capacity. Rather, they are typically related to failures in the transmission and distribution system. In 2011, for example, the Eaton Corporation Blackout Tracker Annual Report identifies 3,071 reported outages in 2011, affecting 41.8 million people (Eaton 2011). Eaton attributes the top five most significant outages of 2011 to a human error at a California facility and to weather events, such as Hurricane Irene and a winter storm in the Washington, D.C., area.

The Department of Energy also tracks unplanned electrical outages in its Electric Disturbance Events (OE-417) form. Electric utilities are required to submit the form whenever there is a sufficiently large electrical outage or disturbance. A review from 2000 to 2011 shows the top five largest outages (in terms of MW) were due to transmission issues. Three of the events to make the list are attributed to the August 2003 blackout that affected about 50 million people in Ohio, Michigan, New York, Pennsylvania, New Jersey, Connecticut, Vermont, and part of Canada. NERC and the Federal Energy Regulatory Commission investigated the outages and found numerous causes, but the key event appears to be fallen tree branches in Ohio. The other two outages are attributed to thunderstorms.

The top five largest outages in terms of customers affected is slightly different. Hurricanes Wilma and Ike account for three of the entries, along with a winter storm in Northern California and the 2003 blackout. Finally, the top five largest outages from 2000 to 2011 can also be categorized by duration of the outage. A transformer fault in Southwest Michigan led to an outage lasting about 54 days, the longest outage in the time period. This was followed by two outages lasting about 34 days, each caused by a fire at a substation in Arizona. Fourth on the list is a 32-day outage caused by severe weather in Alabama in August. In these lists, this is the first to likely have been caused by a lack of generation capacity to meet peak summer demand. Lastly, a 23-day outage in California is attributed to a wildfire, which likely interfered with distribution and transmission lines.

There is no reason to expect that this historic pattern would be affected by the environmental regulations. We find small changes in electricity capacity, especially when compared to the changes that are already expected due to secular changes in the forecasts for natural gas prices and electricity demand (Burtraw et al. 2012). In addition, the cost of pollution control investments should not impose a big impact on the availability of capital to the electricity industry. The approximate annual capital costs for incremental investments in pollution control in the neighborhood of $5.1–$5.4 billion by 2020, although substantial, do not appear especially large for the industry. For example, in 2020 in the baseline, the model predicts incremental expenditure on new generation capacity would amount to capital costs of $25 billion.

6.2 Reliability of Electricity Price

Similarly, electricity prices will not be importantly affected by the implementation of the environmental regulations. We find national average electricity prices increase by roughly 1 percent over the simulation horizon through 2035. This electricity price change accounts for changes in generation and the costs of meeting reserve margins sufficient to ensure reliability.

6.3 Reliabiilty of Industry Profits

The most important effects of MATS are on industry profits, which we measure as producer surplus. The profitability of existing coal-fired plants is especially affected in a negative way, and overall the change in costs for the industry is greater than the change in revenues leading to a decline in profits. However, the decline in the value of coal capacity does not necessarily map into the retirement of these facilities because the decision to operate or retire for existing units depends on their going-forward costs. These costs include the annualized cost of new pollution controls plus fuel and operating costs of generation; they do not include the value of the original investment in the plant. Some relatively important changes in the make-up of the existing capacity have occurred already in the baseline due to changes in natural gas prices and electricity demand. We find the environmental regulations have an important additional effect on profits. Nonetheless, we observe that these facilities continue to operate even in the face of new environmental costs.

6.4 Reliability During the Construction Phase

One way the environmental regulations might pose a reliability concern has to do with the timing of these investments during the period of construction for new pollution controls. During this period, a number of factors might affect the operation of the electricity system. One factor might be the unavailability of equipment for purchase or of vendors or contractors to perform retrofits in a timely manner. The costs and interruption to normal operation will be greater if retrofit construction cannot be scheduled during regular scheduled outages. In addition, if several facilities in the same region schedule concurrent construction activities, it could lead to localized problems. In these cases, local grid planning authorities may force rescheduling of construction activity that could delay a unit's ability to comply.

The EPA has released a plan for addressing case-by-case issues, such as problems caused by delays in permitting or construction, that prevent units from coming into compliance with MATS by the three-year deadline provided to all sources under the Clean Air Act. The agency released a memo (EPA 2011b) along with its final MATS rule detailing its expectation that many sources will be given a fourth year by state environmental permitting authorities to come into compliance. As a result, most affected units will have until early 2016 to meet the new standards. The EPA memo also lays out a path for extending compliance an additional year through administrative order, potentially giving affected units a total of five years to meet the new standards. According to the EPA, this extension is reserved for units that are critical for maintaining reliability and that have been unable to install the necessary pollution controls for reasons beyond the control of the plant's owners or operators. The EPA has asked the Federal Energy Regulatory Commission as well as reliability, transmission, and planning organizations to provide advice on whether units that apply for the extension via administrative order are critical to maintaining reliability.

7. Conclusion

The U.S. electricity industry is undergoing historic changes as a series of pent-up environmental regulations launched over the last two decades finally come to fruition. The two most important new rules, CSPAR and MATS, will come into effect in the next few years. These rules will lead to substantial new investment in pollution controls at existing coal-fired facilities. Compared to the baseline, MATS would lead the introduction of 68 GW of DSI by 2020. CSAPR and MATS together would lead to 88 GW of new DSI. The amount of ACI would grow by about 138 GW in both cases. There would also be about 52 GW of additional fabric filters and 62 GW of upgraded ESP. Finally, there is a small increase in wet scrubbers. In total, these investments represent an annual cost of $5.1–$5.4 billion dollars (2009$).

These substantial investments and costs have led to speculation that there would be substantial retirement of existing capacity. In fact, some important changes that recently occurred in the baseline stemming from projections for lower natural gas prices and electricity demand are expected to lead to retirements. With this as a proper point of departure to measure the impact of the environmental regulations, we find neither the MATS scenario nor the CSPAR & MATS scenario leads to substantial changes in existing capacity by 2020. We expect coal capacity to fall about 1.5 percent under both policy scenarios. Natural gas capacity changes even less.

Another measure of concern to electricity consumers is the reliability of electricity prices. The national average electricity price increases are affected only slightly under both scenarios compared to the baseline. In 2020, the price increase is about 1 percent, from $88/MWh in the baseline to $89/MWh in the MATS scenario, with an even smaller change in the CSPAR & MATS scenario. However, there are regional differences, with the greatest effect in cost-of-service regions where electricity prices increase modestly over the entire simulation horizon. By 2020, the increase in prices in these regions under the MATS policy or with CSAPR & MATS averages about 3 percent.

The increase in costs and the modest change in electricity prices results in a decrease in industry profits. We find producer surplus from existing facilities in 2020 falls by about $3 billion to $5 billion under the policy scenarios for existing generating facilities. This decrease is driven largely by reductions in producer surplus at existing coal-generating facilities, while the surplus associated with new generation increases slightly.

One interesting aspect of the change in costs is the change in the allowance burden. The program design affects the price of allowances that are traded under a cap as well as the regions where those trades can occur. The prescriptive aspect of MATS leads to investments that have the ancillary effect of lowering allowance prices, reducing the allowance burden. For example, in the baseline, 9.8 million Title IV allowances are required to cover SO_2 emissions in 2020, and, at a price of $741/ton, the allowance burden that year is $7.3 billion. Under MATS, the allowance price for SO_2 falls to zero, eliminating this allowance burden. In some cases, that reduced burden accrues to consumers and in some cases it accrues to producers.

In summary, over the modeling horizon, whether MATS is implemented independently or alongside CSAPR, consumers pay for about 70 percent of the costs associated with the regulations and producers pay the other 30 percent. In 2020, for example, total annual costs are $7.1 billion under MATS and $6.6 billion under CSAPR and MATS. All of these producer costs occur in competitive regions of the country because we assume full cost recovery in cost-of-service regions.

With all these investments in place, there is expected to be an important benefit from improved environmental performance for the industry, especially in reduction of emissions of mercury, which are expected to fall by almost 80 percent, and SO_2, which falls by 28–33 percent in 2020 under the different policies.

The main concern of recent public debate has been reliability. The EPA has stated that it does not believe CSAPR or MATS will cause reliability problems or lead to a shortage of generation (EPA 2011b). We find little to substantiate a concern about the reliability of electricity generation capacity or prices. Industry profits may be modestly affected, especially for those firms that own a large portfolio of existing coal plants. A lingering concern is reliability during the transition construction period when these new rules take effect. EPA has committed to flexibility in its enforcement, and the oversight agencies for the electricity industry have made a commitment to safeguard the process. This is the aspect of reliability concern that may still merit the attention of consumers and producers.

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Appendix 1. Pollution Controls

This appendix provides additional details on the control technologies for each pollutant as modeled in Haiku.

NO_x Controls

Model plants use selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR) to control nitrogen oxide (NO_x) emissions. However, existing plants without NO_x controls can only choose to install SCR, not SNCR. All new coal plants are assumed to have SCR installed. SCR and SNCR capital costs, fixed operating and maintenance costs, and variable operating and maintenance costs for coal-fired plants come from engineering formulas contained in Sargent & Lundy (2010a, 2010b). SCR costs for oil and gas steam units come from EPA (2010). The latest Integrated Planning Model documentation does not include costs for SNCR on oil and gas steam units. However, several oil and gas steam units in the Haiku database have SNCR installed. Costs for these controls come from EPA (2006). Removal efficiencies for both SCR and SNCR come from EPA (2010) as well as EPA's National Electric Energy Data System v.4.10, a database that includes geographic, operations, and pollution control information for planned and existing generators.[6]

SO_2 and HCl Controls

Model plants can use wet flue gas desulfurization (FGD), dry FGD, or dry sorbent injection (DSI) technologies to abate emissions of sulfur dioxide (SO_2) and hydrogen chloride (HCl). Existing plants without SO_2 or HCl controls can endogenously select any of these technologies to comply with regulations. However, dry FGD can only be used by plants that burn coal with a sulfur content by weight of no greater than 2 percent, and DSI can only be used by plants that burn coal with an SO_2 emission rate no greater than 2 pounds (lbs) per million British thermal units (Btus). Plants that install DSI must also have a particulate matter (PM) control device and must be at least 25 megawatts or larger. All new coal plants are assumed to have wet FGD installed. Cost information for the three technologies for coal-fired plants comes from engineering formulas in Sargent & Lundy (2010c, 2010d, 2010e).

[6] http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html

PM Controls

Model plants can use electrostatic precipitators (ESP), fabric filters, or both as PM abatement controls. PM controls are specified exogenously, and a model plant is assumed to retain existing PM controls except in two situations. First, an activated carbon injection (ACI) system requires a fabric filter in order to capture the activated carbon, so a model plant without a fabric filter is assumed to build a small fabric filter if it installs ACI. Second, to simulate the MATS policy, some capacity is exogenously assumed to build a fabric filter or upgrade an ESP for compliance with the PM emission rate standard. Coal generators and boilers were selected to install fabric filters or install one of three levels of ESP upgrades based on the list of units that installed these controls provided by the EPA in its Integrated Planning Model documentation for MATS (EPA 2011a). Costs for fabric filters come from engineering formulas in Sargent & Lundy (2011b). Costs for existing ESP technology is assumed to be captured in plants' FERC Federal Energy Regulatory Commission Form 1 cost information, which is included in Haiku.

Mercury Controls

Model plants can comply with mercury standards by installing ACI or through combinations of NO_x controls, SO_2 controls, and PM controls. All combinations of NO_x controls, SO_2 controls, and PM controls achieve different rates of mercury removal depending on the generator's burner type and the type of coal burned. For example, SCR and wet FGD in combination can achieve 90 percent mercury removal when burning bituminous coal without an ACI. Consequently, new coal plants are assumed to not have ACI, and ACI cannot be added to plants with SCR and wet FGD, because this mercury removal rate is sufficient for current regulations. Cost information for ACI comes from engineering formulas contained in Sargent & Lundy (2011a). Mercury removal efficiencies come from EPA (2010).

Appendix 2. Modeling MATS

Mercury

MATS sets emissions standards for mercury that depend on the rank of coal the boiler is designed to burn. For existing coal plants designed to fire low-rank coal (lignite), the plant must meet one of two standards—either 4 lbs per trillion Btus of heat input or 0.04 lbs per gigawatt-hour (GWh) of electricity production. Other existing coal plants must meet one of two other standards—either 1.2 lbs/trillion Btus or 0.013 lbs/GWh. In Haiku, it is assumed that a model plant that endogenously chooses to burn lignite must comply with the first set of standards and the other model plants, which endogenously select higher-rank coals, must comply with the second set. Since each plant must comply with only one of the two standards, either in terms of lbs/trillion Btus or lbs/GWh, Haiku uses the average heat rate of the model plant to determine which standard is less stringent, and this is the standard that the model plant must meet.[7]

For a model plant not in compliance, these emissions rate standards can be met by switching to a coal type with a lower mercury content, installing pollution controls that remove mercury from emissions, or both. Haiku's pollution control module simultaneously selects the optimal coal type and pollution control choice for each model plant. In doing so, the model determines which combinations of coal type and pollution control are feasible and only selects from this set. If a combination of coal type and pollution control yields an emissions rate greater than the standard, that combination is not allowed. If no combination is feasible, the model plant cannot operate. This restricts all existing coal model plants to comply with the MATS mercury emission rate standard or to not operate if the standard cannot be met.

Other Heavy Metals

MATS regulates the emissions of filterable particulate matter (PM) as a surrogate for non-mercury heavy metals. All existing coal plants must meet one of two emissions rate standards for filterable PM—either 0.03 lbs/million Btus or 0.3 lbs per megawatt-hour (MWh). Haiku does not have information on the particulate content of different types of coal nor how plant operations and pollution controls affect PM emissions. However, EPA documentation on the Integrated Planning Model (EPA, 2011b) includes exogenous assumptions about what upgrades, if any, must be performed at each boiler to meet this PM standard. The compliance options include three levels of upgrades to existing electrostatic precipitators and the construction of a fabric filter. Haiku uses this information to exogenously specify the compliance strategy for each model plant to meet the MATS filterable PM emissions rate standard.

Acid Gases

MATS limits the emissions of hydrogen chloride (HCl) as a surrogate for acid gases. All existing coal plants must meet one of two emissions rate standards for HCl—either 0.002

[7] Haiku aggregates generators with similar characteristics into model plants. Since a model plant is composed of many generators that do not necessarily have identical heat rates, it is the average heat rate of the constituent generators that is used to determine which standard is less stringent for the model plant as a whole.

lbs/million Btus or 0.02 lbs/MWh. As with the mercury standard, Haiku uses the model plant's average heat rate to determine which of these two standards is less stringent—and that is the emissions rate that must be met. Alternatively, plants with a flue gas desulfurization (FGD) system in place may instead comply with one of two emission rate standards for sulfur dioxide (SO_2)—either 0.2 lbs/million Btus or 1.5 lbs/MWh—with the less stringent standard selected as above.

As with mercury, these standards can be met by switching to a coal type with a lower pollutant content, installing pollution controls that remove the pollutant from emissions, or both. As stated above, if a combination of coal type and pollution control does not comply with this standard, it cannot be selected. For a model plant without FGD (or that does not endogenously choose to add FGD), the HCl standard must be met for the combination to be allowed. If a model plant has an FGD system, either the HCl or the SO_2 standard can be met for the combination to be allowed. This ensures all existing coal model plants are complying with the MATS acid gases emissions rate standard or not operating if the standard cannot be met.