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# Retail Electricity Price Savings from Compliance Flexibility in GHG Standards for Stationary Sources

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## **Abstract**

The EPA will issue rules regulating greenhouse gas (GHG) emissions from existing steam boilers and refineries in 2012. A crucial issue affecting the scope and cost of emissions reductions will be the potential introduction of flexibility in compliance, including averaging across groups of facilities. This research investigates the role of compliance flexibility for the most important of these source categories—existing coal-fired power plants—that currently account for one-third of national emissions of carbon dioxide, the most important greenhouse gas. We find a flexible standard, calibrated to achieve the same emissions reductions as an inflexible approach, reduces the increase in electricity price by 60 percent and overall costs by two-thirds in 2020. The flexible standard also leads to substantially more investment to improve the operating efficiency of existing facilities, whereas the inflexible standard leads to substantially greater retirement of existing facilities.

**Key Words:** climate policy, efficiency, EPA, Clean Air Act, coal, compliance flexibility, regulation

**JEL Classification Numbers:** K32, Q54, Q58

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Dallas Burtraw, Anthony Paul, and Matt Woerman\*

## 1 Introduction

The direction of climate policy in the U.S. has changed course with the failure of legislative proposals and the recent court decision (*Massachusetts v. EPA*) confirming the authority of the Environmental Protection Agency (EPA) to regulate GHG emissions under the Clean Air Act (CAA). Regulation will unfold in three major venues. In January 2011 the EPA issued new vehicle fuel efficiency standards (“Corporate Average Fuel Efficiency”) affecting model-year 2012 vehicles, with standards tightening over time. Secondly, the agency put in place GHG permitting procedures (“New Source Review”) affecting major new sources and major modifications at existing sources. Third, the EPA will develop a regulatory framework to regulate existing stationary sources with performance standards analogous to those applying to new sources. That framework will provide guidelines to states for the development of plans that will be implemented by the states. The first of these standards will regulate the performance of steam boilers and refineries at new and existing facilities, with draft rules expected in September 2011 and final rules expected in March 2012.

The third category—regulation of existing stationary sources—is likely to be the most important and within this category the regulation of electricity generation is key. Electricity generation causes 33 percent of U.S. greenhouse gas (GHG) emissions including 40 percent of carbon dioxide (CO<sub>2</sub>) emissions. More importantly the electricity sector is expected to account for two-thirds to three-quarters of economy-wide emissions reductions under a cost-effective implementation of greenhouse gas policy (EIA 2009a; EPA 2009). Consequently the introduction of policy to reduce GHGs emissions could have important effects on the electricity sector. Most affected will be the operation of coal-fired power plants, which account for 82.5 percent of electricity sector emissions, or 33.3 percent of total US emissions (EIA 2009a).

This research investigates alternatives for regulation of existing coal-fired power plants and the potential magnitude of emissions reductions from these plants, and compares these

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options with recent legislative proposals. In particular, we examine the effect on costs from introducing flexibility in compliance. Two regulatory approaches that might emerge under the CAA would impose energy efficiency-based or emission rate-based performance standards for new and existing power plants (Richardson, Fraas, and Burtraw 2011).<sup>1</sup> One variation could adopt strict, inflexible performance standards, and a second could allow compliance flexibility such that standards might not necessarily be achieved at an individual facility, but would be achieved on average. Either of these approaches would target technological performance but would not explicitly cap emissions. Two other approaches involve cap and trade. One would initially distribute emissions allowances through a revenue-raising auction.<sup>2</sup> The second would distribute emissions allowances for free to local distribution companies (LDCs).<sup>3</sup> The cost increase is closely tied to the level of effort (stringency) required by the policy. To facilitate a comparison of their cost effectiveness these various policies are calibrated to achieve equivalent emissions reductions of 5.4 percent (141 million short tons) from baseline in 2020.

To model these policies we employ a highly parameterized regional, intertemporal economic model of investment and operation of the U.S. electricity system. Our primary indicator of the regulatory impact on the electricity sector is the change in retail electricity prices. We also evaluate several other outcome measures including changes in investment and the operating efficiency of existing plants.

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<sup>1</sup> The distinction between these measures is subtle. Because the carbon content of fossil fuel varies little within each fuel type (coal, gas, oil) there is almost a one-to-one mapping between these measures for fossil-fired power plants that have no post-combustion controls for greenhouse gases. As an example, combustion of Powder River Basin low-sulfur subbituminous coal emits 212.7 lb CO<sub>2</sub> per MMBtu of heat content, or  $2.127 \times 10^{-4}$  lb CO<sub>2</sub>/Btu. The product of this rate and the plant's heat rate gives the emission rate of the plant. For example, a plant with a heat rate of 10,000 Btu/kWh has a CO<sub>2</sub> emission rate of 2.127 lb CO<sub>2</sub>/kWh ( $2.127 \times 10^{-4} \times 10,000$ ). However, if a plant was to co-fire with biomass, then its energy efficiency measured by its "heat rate" (Btu/kwh) could go up, implying worse performance, while its emissions rate (CO<sub>2</sub>e/kwh) might go down (depending on emissions assigned to biomass), implying better performance. The same disparity could emerge with the installation of post-combustion carbon capture technology. Consequently an emissions rate standard would be preferable as a regulatory approach but in this paper it is roughly equivalent to a heat rate standard because we do not allow for retrofit of CCS at existing facilities. In sensitivity analysis we allow for biomass cofiring to count toward compliance with the heat rate standard.

<sup>2</sup> Under the Clean Air Act a federal auction of allowances by the Environmental Protection Agency could not occur, and the breadth of the trading program would be restricted. States would play a large role in implementation and enforcement under the Clean Air Act, and if trading were permissible states conceivably could auction allowances.

<sup>3</sup> Both of these approaches were embodied to varying degrees in recently proposed federal legislation, and are embodied in California's cap and trade program that is slated to begin in 2012. The auction approach is the predominate method used in the Regional Greenhouse Gas Initiative trading program in ten northeastern states.

In brief, we find the flexible standard results in an increase of 1.3 percent in electricity prices. This compares to an increase of 3.3 percent under an inflexible standard. We find the overall costs of a flexible standard including the costs on firms are just one-third that of an inflexible standard. We also find that a flexible approach leads to substantially greater investment to improve the efficiency of existing facilities, while an inflexible standard leads to substantially greater retirement of existing facilities than does a flexible approach.

The change in electricity prices is likely to vary by region of the country because regions vary in the quantity of electricity consumption and the type of fuel and technology used for electricity generation. Moreover many regions rely heavily on electricity generated in other states or regions of the country, at least during certain seasons or times of day, and the fuel and technology used for electricity generation varies across time. For these reasons the change in electricity price by region may not depend entirely on the emissions intensity of generation in that region.

## **2 Scenarios and Approach**

As described above, we define four policy cases with equal emissions reductions. However, the implementation of technology performance standards under the Clean Air Act is not expected to specify an emissions cap. Therefore, to establish equivalency we solve the regulatory policies first to obtain emissions reductions in 2020, and that outcome is introduced directly as an emissions cap in the other two policies. These reductions are compared to a business-as-usual baseline that is built on fuel price forecasts contained in the EIA's Annual Energy Outlook for 2011.<sup>4</sup> The four policy approaches to be evaluated are summarized in Table 1 and described below.

### **2.1 Flexible Performance Standard for Coal-Fired Plants**

The flexible policy is designed to achieve a 5 percent improvement from the observed 2010 average operating efficiency of coal-fired power plants by 2020. By 2020, this translates into a 5.2 percent improvement due to a decline in efficiency across the fleet in the baseline between 2010 and 2020, in part due to increasing utilization of less efficient plants to meet growing demand. The efficiency of a plant is measured by its heat rate, which represents the

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<sup>4</sup> EIA (2011). Other aspects of the baseline including demand forecasts are calibrated to the Annual Energy Outlook for 2010 EIA (2010). Further detail on the model is presented below.

quantity of fuel (Btu) needed to produce a unit of electricity (kWh). A percentage improvement in heat rate is nearly equivalent to an equal percentage improvement in the emissions rate in terms of the change in emissions of CO<sub>2</sub>. The difference stems from slight variation in carbon per Btu in varieties of coals. Nonetheless in practice an emissions rate standard would provide incentives for this opportunity for emissions reductions and would be preferable, but it is not modeled here. The performance standard is phased in linearly beginning in 2012 and fully implemented in 2020. Improvement in average heat rate can be achieved either through improvements in the operating efficiency at plants not meeting the standard, improvements at plants that already meet the standard, or reduced utilization of relatively inefficient plants.

**Table 1. Scenario Descriptions**

(2020 data)	Baseline			
Demand	Calibrated to AEO 2010			
Fuel supply and prices	Functions calibrated to AEO 2011			
Initial generation capacity	Calibrated to 2008 plant data			
Environmental regulations <sup>1</sup>	CAIR			
Electricity Price (\$/MWh)	86.91			
Heat Rate at Coal Facilities (Btu/kWh)	10,182			
Efficiency Investments (M\$)	189			
Cost of Coal (\$/MMBtu)	1.96			
Cost of Gas (\$/MMBtu)	5.35			
CO <sub>2</sub> Emissions (Mtons)	2,631			
	Flexible Compliance	Inflexible Standard	Cap and Trade (LDC)	Cap and Trade (auction)
Policy	Tradable performance standard	Inflexible heat rate performance standard	Emissions cap and trade with free allocation to local distribution companies	Emissions cap and trade with auction
Policy target <sup>2</sup>	5% improvement in heat rate at coal-fired plants (9,657 Btu/kWh) by 2020. Requirement phased in linearly beginning 2012.	Maximum heat rate 10,300 (Btu/kWh) by 2020 phased in beginning 2012.	Cap phased in beginning 2012.	Cap phased in beginning 2012.
CO <sub>2</sub> reductions	141 million tons	141 million tons	141 million tons	141 million tons

1) The Cross-State Air Pollution Rule and Utility MACT are not included.

2) Policy targets are calibrated to achieve emissions reductions comparable to the Flexible Compliance Policy.

We label the mechanism for transferring credit for generation at relatively efficient plants to relatively inefficient plants as a generation efficiency credit offset (GECO), which is denominated as Btu/kWh. Plants that are efficient relative to the benchmark (Btu/kWh) earn transferable credits on net, and plants that are relatively inefficient need to obtain such credits. In the simulation model below the benchmark is set at 9,657 Btu/kWh. The credits have a monetary value (\$) and are earned (and surrendered) on every kWh of production. Consequently the GECO price is denominated in  $\$/(\text{Btu/kWh})/\text{kWh} = \$/\text{Btu}$ . We calculate a national equilibrium price for GECOs within the electricity market model.

Although the standard may lead to some fuel switching from coal to natural gas or other technologies, it is not designed to encourage that. Since the standard is specified in terms of plant efficiency, rather than an emissions cap, only improvements in plant operating efficiency and greater utilization of relatively efficient coal plants receive credit toward compliance. There is no credit given for retirement of plants, greater use of natural gas or biomass or natural gas cofiring. The emission reduction that is achieved across the sector, accounting for changes in utilization of all technologies, provides the emissions reduction target of 5.4 percent that is used in the other scenarios.

## **2.2 Inflexible Performance Standard for Coal-Fired Plants**

The inflexible performance standard is constructed around technological opportunities to achieve improvements in the operating efficiency of coal-fired power plants. Plants with operating efficiency that does not meet the standard would either have to retire or make improvements in operating efficiency to come into compliance. The inflexible standard could lead to some substitution away from coal, but it is not designed to encourage that. The inflexible standard is solved repeatedly to find a heat rate standard that achieves total emissions reductions for the sector equal to the emissions target.

## **2.3 Cap and Trade with Auctioned Emissions Allowances**

The cap-and-trade approach allows full flexibility in how the industry responds to the introduction of a price on CO<sub>2</sub>. In principle, a trading program may allow for temporal flexibility through banking (and potentially borrowing) of emissions allowances. However, to facilitate comparison across the four scenarios we do not allow for emissions banking, so emissions caps are set equal to emissions outcomes in every year under the performance standard.

An auction of emissions allowances would yield substantial revenue that must be accounted for. We assume the auction revenue displaces the need for other sources of revenue



and value it on a dollar per dollar basis.<sup>5</sup> To facilitate comparison across policy approaches we report the auction revenue per kWh of consumption.

#### **2.4 Cap and Trade with Free Allocation to Local Distribution Companies**

Allowances distributed to LDCs would be sold or auctioned to entities with a compliance responsibility. The sale of allowances would provide a revenue stream that could be used to offset much of the increase in costs that is expected in the wholesale power market as a result of the cap and trade program. Since LDCs are regulated, they can be expected to pass the benefits of the free allocation on to customers in one way or another, leading to smaller changes in retail electricity prices than would cap and trade with an auction.

There are several issues that surface in the design of free allocation to LDCs. The formula by which allowance value is apportioned to LDCs could depend on relative population, consumption or the emissions intensity of consumption. We use a weighted average based equally on the historic emissions intensity of consumption and an updated measure of relative consumption by each LDC aggregated at the 21 regions in the model. This is roughly equivalent to the approach embodied in the Waxman-Markey legislation (HR 2454).

At the LDC level, another important decision is how allowance value is distributed across the residential, industrial and commercial customer classes. We distribute the value such that each class receives a share proportional to its level of consumption in the baseline. Moreover, the way value is returned could have a substantial impact on the results. If value were used to offset variable costs, and if customers perceive variable costs distinct from average electricity prices, then the allocation to LDCs could have a potent effect in leading to more electricity consumption. If consumers do not differentiate variable costs from average price then it would have a modest effect, since average price would change by less than variable costs. Instead, if the value were used to offset fixed costs associated with transmission, distribution and billing costs, and if customers perceive variable costs distinct from average electricity prices, then customers would perceive that variable electricity prices increase in a way comparable to the auction scenario and a greater reduction in electricity demand would result. However, evidence suggests that residential class customers would not distinguish the variable cost change from the change in

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<sup>5</sup> If the auction revenue displaces other taxes its value may be more than one dollar because the marginal cost of funds for other taxes is typically measured at greater than one dollar.

the average price (Ito 2010; Borenstein 2009). On the other hand commercial and industrial class customers may be able to distinguish this difference.

In order to illustrate the differences in the policy approaches as clearly as possible, we model LDC allocation as reducing variable costs for all customers. This means that all customers would see lower electricity prices than under an auction and greater consumption would be expected as a result, which will raise the price of tradable emissions allowances compared to the auction (Paul, Burtraw, and Palmer 2010; Burtraw, Walls, and Blonz 2010).

### 3 Background

The U.S. Supreme Court's decision in *Massachusetts v. EPA* confirmed the authority of the Environmental Protection Agency (EPA) to regulate GHGs under the Clean Air Act (CAA). In response the EPA initiated a scientific inquiry and subsequently made a finding of "endangerment" establishing the threat of GHG emissions to human health and the environment, which subsequently compels the EPA to mitigate that harm. The first regulation attempting to do so is the revised fuel efficiency standard for cars and trucks and construction permitting mentioned previously. Next the EPA will regulate stationary sources. Among several regulatory options for stationary sources the EPA has committed to promulgating performance standards under §111(b) for new sources (these are termed New Source Performance Standards, or NSPS), and under §111(d) for existing sources. These are technology based standards, but there exists significant opportunity for the flexibility in achieving compliance with the standards, including tradable performance standards that could allow averaging of emissions rates across sources to achieve emissions reductions in a cost effective manner (Burtraw, Fraas, and Richardson 2011; Monast, Profeta, and Cooley 2010; Mullins and Enion 2010; Richardson, Fraas, and Burtraw 2011). Two important questions are the magnitude of reductions that might be achieved and the potential cost savings and other impacts that might result from flexible compliance.

The EPA's advance notice of proposed rulemaking (ANPR) EPA (2008a) provides information about the first of these questions—the potential magnitude of emissions reductions at various facilities including most importantly at coal-fired power plants.<sup>6</sup> These plants are able to reduce CO<sub>2</sub> emissions by upgrading and modifying various plant systems, which would improve plant efficiency. The ANPR notes that heat rate reductions of up to 10 percent may be

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<sup>6</sup> Burtraw, Fraas, and Richardson (2011) provide a summary of EPA findings in this and subsequent white papers.

possible at some individual units. Over the entire fleet, however, the average heat rate reduction could reasonably be expected to be 2 to 5 percent. A reduction in heat rate translates directly into a reduction in CO<sub>2</sub> emissions per unit of electricity generation. The current fleet-wide average heat rate is about 10,300 Btu/kWh, and ranges from below 9,000 to above 15,000 Btu/kWh (EPA 2008b).

Additionally, as older coal-fired power plants are retired, new and more efficient coal-fired plants may replace that capacity. A new supercritical coal-fired power plant is designed to operate at a heat rate about 8,500 Btu/kWh, an 18 percent improvement over the current fleet-wide average (EPA 2008b). Future ultra-supercritical plants may achieve a heat rate reduction of 23 percent over the current average. As these new plants are built, they will be included in fleet-wide calculations, and thus will have a bearing on future revised standards for existing coal-fired power plants.<sup>7</sup>

EPA (2008b) also notes the potential role of co-firing biomass, which subject to physical, operational, and biomass-supply constraints, could replace up to 10 percent of the heat input from coal without substantial modifications to existing plants. Regional and seasonal constraints on biomass availability further restrict the ability to co-fire biomass, leading to the conclusion that 2 to 5 percent of coal use may be substituted with biomass. If one views biomass supply as roughly carbon neutral, this would reduce CO<sub>2</sub> emissions by 2 to 5 percent.<sup>8</sup>

DiPietro and Krulla (2010) address the opportunity to improve average operating efficiency by studying the current distribution of plants and conclude that heat rates could reasonably increase from their estimate of the current level of about 10,498 to 9,477.<sup>9</sup> They find plants in the top performing decile in 2008 had an average heat rate of efficiency of 9,074, while the bottom decile had an average heat rate of 12,362. Plants in the top decile are typically larger, have higher steam pressures, and burn a higher percentage of bituminous coal; nonetheless some

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<sup>7</sup> For example, if a standard was based on the heat rate of the 90<sup>th</sup> percentile plant, then new plants might decrease the heat rate of the 90<sup>th</sup> percentile plant and consequently decrease the heat rate required by the standard.

<sup>8</sup> This volume of biomass is roughly comparable to waste agriculture and forestry products. At this scale biomass cofiring would introduce much less competition for resources than would closed-loop dedicated biomass generation.

<sup>9</sup> The authors discuss the operating efficiency of plants, which we convert to heat rate. One kWh of electricity contains 3,412 Btu of energy. A coal plant that perfectly converted the heat content of coal into electricity, and thus had an operating efficiency of 100%, would have a heat rate of 3,412 Btu/kWh. As the operating efficiency of the plant falls from this level the heat rate increases. Converting from operating efficiency to heat rate is done by dividing 3,412 Btu/kWh by the operating efficiency. For example, a plant with an operating efficiency of 32.5% has a heat rate of 10,498 Btu/kWh (3,412/0.325).

top-decile plants have capacities and steam pressures that are less than the fleet-wide average. Also, the average plant age and capacity factor in the top decile are approximately equal to the fleet-wide averages. Thus, although some quasi-fixed factors greatly influence plant efficiency, most plants still have the ability to improve net efficiency despite existing technical characteristics. At 2008 generation levels, the emissions reductions from improving average heat rate to 9,477 would total 175 million metric tons annually.

Bianco and Litz (2010) consider such technology options in the context of three levels of ambition for performance standard regulations. In their “lackluster” scenario, existing coal-fired plants are required to reduce heat rates by 5 percent, as described in the EPA’s ANPR; new coal plants are required to meet the emission rate of a natural-gas-fired unit, which the authors state could be achieved by natural gas cofiring, carbon capture and storage, co-firing coal with biomass or utilizing waste heat. In the “middle-of-the-road” scenario, existing coal plants are required to reduce heat rates by 7.1 percent from 10,498 to 9,693; new coal plants are required to meet an emissions standard equivalent to a coal plant with 90 percent carbon capture and storage. In both these scenarios, the regulation of new sources would not have a near-term effect since they project no additional coal plants will be built before 2025.

Their “go-getter” scenario would introduce a cap-and-trade program covering all plants with the cap level set equal to the reductions that would be achieved in the power sector under the Waxman-Markey proposal although the authors note these reductions would likely be delayed by approximately four years if they are to be accomplished through NSPS rather than legislation. According to EIA modeling of the proposal (EIA 2009), the power sector would reduce emissions 8.5 percent below 2012 levels in 2020 and 52 percent below 2012 levels in 2030. It is important to note these reductions are for the entire electric power sector. The reduction in emissions intensity at coal plants would likely be less than these values, and many reductions would be achieved by shifting away from coal-fired power.

NETL (2010) identifies 50 opportunities for implementation of efficiency improvements at coal-fired power plants, many of which are available to most of the fleet, as well as many barriers to achieving these improvements. These opportunities include training and incentives for workers, turbine upgrades and major boiler retrofits. Barriers include the difficulty in measuring coal plant efficiency in real time. Another is the lack of a financial incentive to improve efficiency, since regulated utilities can pass through fuel costs to consumers and lower operation and maintenance (O&M) costs are typically preferred to efficiency gains. Further, there can be uncertainty associated with efficiency improvements, including the downtime and lost revenue

required to make the plant system upgrades and risk of the upgrade triggering construction permitting requirements under New Source Review.

Sargent & Lundy (2009) provide a more in-depth examination of a set of specific technologies that could improve efficiency at coal-fired power plants. A representation of these technologies and their associated costs are included in our modeling:

- Economizer to transfer more heat from exhaust gases to boiler feedwater,
- Neural network to more accurately predict and optimize power plant performance,
- Intelligent sootblowers to remove ash buildups that reduce heat transfer,
- Air heater and duct leakage control to reduce air leakage at heat exchangers,
- Acid dew point control to extract more heat from flue gas without corroding the air heater,
- Turbine overhaul to improve turbine efficiency through design and materials used,
- Condenser cleaning to lower the steam condensing temperature and improve turbine efficiency,
- Boiler feed pump to reduce auxiliary power usage,
- Induced draft axial fan and motor to maintain proper flue gas flow, and
- Variable-frequency drives to improve fan motor control.

In an average 500 MW coal plant, air heater and duct leakage control could produce a heat rate improvement of 10-40 Btu/kWh; at the high end turbine overhaul could produce potential improvement of 100-300 Btu/kWh. All of these technologies, except condenser cleaning (which only requires fixed O&M costs), require capital costs to install or upgrade the plant systems ranging from \$0.5 million for intelligent sootblowers to \$4-20 million for turbine overhaul. Many of the technologies also have fixed O&M costs that range annually from \$30,000 for variable-frequency drives to \$100,000 for the economizer. Assuming a capital charge rate of 10 percent, these costs result in average efficiency costs of \$0.28-\$38.65/MMBtu of heat input reduced, or \$0.02/MWh to \$0.65/MWh of electricity generated.<sup>10</sup> Although this is a wide range

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<sup>10</sup> The capital charge is calculated based on the cost of capital and the capital recovery period. In our model the charge for pollution controls and investments at existing capacity is 10.19%. For new coal plants it is 11.67%.

of costs, it illustrates that some low-cost efficiency improvements may be available for an average coal-fired power plant, and that more effective, but higher cost, measures also may be available.

Performance standards requiring the implementation of these measures may be effective but they may not be the least-cost option to achieve emissions reductions. Tietenberg (1990) lists ten empirical studies that examined the cost of command-and-control regulation for air pollution control compared to the theoretical least-cost option to achieve the same level of emissions, including many different air pollutants and geographic areas across the United States. These studies find that the command-and-control policies range in cost from 1.07 to 22.0 times that of the least-cost policy option. Harrington, Morgenstern, and Nelson (2000) retrospectively evaluate the performance of flexible market-based approaches and find that expected costs savings compared to command and control regulation have usually met or exceeded expectations.

Stavins and Newell (2003) further analyze the cost difference between the theoretical cost minimum, which is achieved through the use of a market-based policy instrument, and traditional command-and-control approaches represented by a uniform emission rate standard and a uniform percentage reduction standard. They examine how heterogeneous emitters affect total abatement costs by considering heterogeneity in the baseline emission intensity and the slope of the marginal abatement cost curve. They find that greater heterogeneity in either of these sources increases the cost savings potential of a market-based policy, and also that the level of reductions amplifies the cost savings due to heterogeneity. However, they also mention several reasons why a market-based policy may not achieve the theoretical cost minimum and may be less cost-effective than traditional command-and-control regulations including administrative, transactions, and political costs, possible strategic behavior under a market-based policy, and systematic over-control under some command-and control regulations.

#### **4 Model**

The scenarios are examined using RFF's Haiku electricity market model, which solves for investment and operation of the electricity system over a twenty-five year horizon in 21 linked regions in the continental U.S. (Paul, Burtraw, and Palmer 2009). Each simulation year is represented by three seasons (spring and fall are combined) and four times of day, with price responsive demand functions for residential, commercial and industrial customer classes. Supply is represented using 55 model plants in each region that aggregate capacity according to technology and fuel source from the complete set of commercial electricity generation plants in

the country. Coal model plants have a range of capacity at various heat rates, representing the range of average heat rates at the underlying constituent plants, which is extrapolated slightly subject to some boundary constraints.

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 EIA in the AEO 2010. Fuel prices are benchmarked to the forecasts of the AEO 2011 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 of these 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. Discounting for new capacity investments is based on an assumed real cost of capital of 8 percent. Investment and operation include pollution control decisions to comply with regulatory constraints for sulfur dioxide, nitrogen oxides and mercury, including equilibria in emissions markets.<sup>11</sup> All currently available technologies are represented in the model as well as integrated gasification 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.<sup>12</sup> 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.

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<sup>11</sup> As noted previously, the Cross State Pollution Rule and the Utility Air Toxics Rule (MACT) are not included.

<sup>12</sup> 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.

The model includes a representation of opportunities to improve the operating efficiency of existing coal-fired power plants. The schedule is derived from information contained in EPA (2008b) and a recent engineering report from Sargent & Lundy (2009). We lack data about the degree to which these opportunities have already been implemented by plants. Therefore we have to make assumptions about the opportunities available to plants based on their observed heat rates. We order these measures by their average cost and fit a line to estimate a schedule of opportunities representing a supply curve for energy efficiency measures at existing plants. The full schedule encompasses heat rate improvements of approximately 700 Btu/kWh<sup>13</sup> at an annual cost (capital and O&M) ranging from zero to approximately \$35/MW per Btu/kWh improvement. We assume this supply curve represents engineering knowledge in 2008, and we grow the supply curve at 1 percent per year at the extensive margin, meaning that 1 percent of additional measures are available each year at increasing cost relative to the supply curve (i.e. the supply curve is made longer) ultimately yielding opportunities for 788.8 Btu/kWh in 2020.<sup>14</sup>

For each model plant we assume that observed heat rates are inversely related to installation of identified measures; i.e. less efficient plants start further down the supply curve and have more options available to them. The benefits of efficiency improvements include decreased costs for fuel and pollution permits, efficiency credits in the case of a flexible program, and potentially greater revenue if equilibrium electricity prices are affected (this outcome differs in competitive and cost-of-service regions). The opportunities and costs of an investment differ for every MW of capacity within a model plant according to its existing heat rate. We anchor the supply curve assuming any MW of capacity with heat rate greater than 11,500 Btu/kWh has all options available. The most efficient MW of capacity across the fleet has no options available, and the schedule is linear between these values. The choice of 11,500 as an anchor was made through repeated simulations that were evaluated to balance investments chosen in the model in the baseline and retirement that occurs under an inflexible standard. For example, capacity with a heat rate greater than 11,500 plus 788.8 (the maximum possible improvement in 2020) are necessarily forced to retire under an inflexible standard set at 11,500 Btu/kWh in 2020. In the baseline, we see \$86 million of investment in energy efficiency

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<sup>13</sup> The amount of heat rate improvements available and the slope of the supply curve vary depending on the size of the plant, but these are approximate midrange values.

<sup>14</sup> Also note the model assumes costs along the supply curve fall at 0.05% per year. (The supply curve slope is reduced.)



measures in 2010 under this specification. Richardson et al. (2011) and NETL (2011) suggest reasons why potential cost savings are left unrealized in the baseline.

The model allows for biomass cofiring at coal plants, which is observed in the baseline. Cofiring does not contribute to the calculation of heat rate improvements in our main analysis, although in the cap and trade scenarios we observe some increase in the use of biomass as a response to incentives provided by the allowance price. In a sensitivity analysis we consider the potential role for biomass cofiring as a way to reduce costs.

## 5 Analysis

To facilitate comparison each policy is calibrated to achieve comparable reductions in emissions. Recall the flexible and inflexible standards are phased in linearly beginning in 2012 and they are fully phased in by 2020. The results for 2020 are reported in Table 2.

### 5.1 Electricity Prices

In 2020 the greatest change in electricity price occurs under an inflexible standard (\$2.84/Mwh or 3.3 percent) and it is 85 percent greater than the change that would result under a cap-and-trade with an auction and 245 percent greater than under a flexible approach. The price change under the flexible approach, compared to the national average baseline level of \$86.91/MWh, is \$1.16 (1.3 percent). The cap and trade with auction has a greater effect on electricity price because of the allowance purchase requirements. In contrast, the cap and trade approach with allocation to LDCs yields no increase (in fact a slight decrease) in electricity prices. This outcome occurs because the vast majority of price changes under cap and trade result from the introduction of a price on emissions allowances but under LDC allocation, the increase in the cost of production is offset from the allowance price is offset by the allocation of allowance value to LDCs.<sup>15</sup>

The regional-level changes in electricity prices are reported in Table 3. Under the flexible standard the largest change from baseline occurs in the Plains region and in the Rockies and the West, while expected prices fall in other regions of the country. In contrast, under the inflexible standard prices rise everywhere except the Southeast. That region has the smallest percentage of

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<sup>15</sup> Several authors have noted that electricity prices could actually fall slightly because prices are affected by the mix of technologies and fuels that determine the marginal cost of production, and that mix is affected by the introduction of a cost on CO<sub>2</sub> emissions under cap and trade (see for example Paul et al. 2010).

coal retirement and consequently builds the least new natural gas capacity. In addition, the power exports from the region increase, which provide revenue to the rate base. Since this is a regulated cost-of-service region, that revenue helps to offset increases in electricity price that otherwise might occur. Comparison of these two policies indicates a lower price in every region except the Plains under the flexible standard.

We also decompose the regions according to market structure. The regulated cost-of-service regions see virtually no change in electricity price between the flexible and inflexible standards; however the competitive regions see a big difference. The price change under the inflexible standard is \$4.61/MWh (4.3 percent) but it is almost zero under the flexible standard. This illustrates that in the cost-of-service regions the financial transfers between relatively inefficient and efficient facilities about nets out in its influence on electricity price.

**Table 2. Comparison of Scenarios Achieving Equal Reductions in CO<sub>2</sub><sup>1</sup>**

Year 2020 Values in 2008 dollars	Flexible Compliance	Inflexible Standard	Cap and Trade (LDC)	Cap and Trade (auction)
<b>Change in Elec. Price (\$/MWh)</b>	1.16	2.84	-0.25	1.54
	1.3%	3.3%	-0.3%	1.8%
<b>Change in Generation<sup>2</sup> (BkWh)</b>	-40	-74	-7	-49
	-0.9%	-1.7%	-0.2%	-1.1%
Coal	-114	-209	-32	-42
	-5.9%	-10.9%	-1.7%	-2.2%
Gas	79	132	37	5
	7.8%	13.1%	3.7%	0.5%
<b>Change in Capacity<sup>2</sup>(GW)</b>	-0.6	-3.2	7.4	-3.3
	-0.1%	-0.3%	0.7%	-0.3%
Coal	-5.5	-32.6	-3.2	-4.1
	-2.0%	-11.9%	-1.2%	-1.5%
Gas	6.2	29.7	10.7	0.9
	1.5%	7.0%	2.5%	0.2%
<b>Avg. Coal Plant Heat Rate (Btu/kWh)</b>	9,657	9,914	10,149	10,160
<b>Avg. Effic. Improve. (Btu/kWh)</b>	525	268	33	22
	5.2%	2.6%	0.3%	0.2%
<b>Efficiency Investments (M\$)<sup>3</sup></b>	2,933	349	117	92
<b>GECO Price (\$/MMBtu)</b>	26.4			
<b>CO<sub>2</sub> Price (\$/ton)</b>			4.0	3.2
<b>Cost of Coal (\$/MMBtu)</b>	1.95	2.02	1.95	1.95
<b>Cost of Gas (\$/MMBtu)</b>	5.42	5.45	5.40	5.35
<b>Change in Total Cost (B\$/year)</b>	1.4	4.9	0.5	2.6
Consumer Cost	1.9	7.0	-0.9	3.4
Producer Cost	-0.4	-2.3	1.4	1.5
Cost to Government	-0.2	0.2	-0.1	-2.3
<b>Change in Cost / MWh (\$/MWh)</b>	1.9	5.8	0.4	3.2
	2.8%	8.4%	0.7%	4.7%

1) CO<sub>2</sub> emissions reductions across the electricity sector are 141 million tons from baseline, or 5.4%.

2) Change in total generation and capacity include changes in addition to coal and gas plants.

3) Cost of efficiency improvements include investments in capital and changes operating procedures.

**Table 3. Regional Price Changes**

Year 2020 Values in 2008 dollars	Flexible Compliance	Inflexible Standard	Cap and Trade (LDC)	Cap and Trade (auction)
RGGI	-0.40	4.75	-2.28	-0.54
Rockies & West	2.69	3.22	-0.42	1.10
Big 10 & Appalachia	-0.25	4.10	-0.25	1.71
Southeast	-0.38	-0.41	0.44	1.93
Plains	5.03	4.53	0.00	2.20
Wholesale Competition	0.12	4.61	-1.53	0.90
Cost of Service	1.79	1.75	0.52	1.92
<b>National</b>	1.16	2.84	-0.25	1.54

## 5.2 Generation and Capacity

Changes in generation mirror changes in electricity price. The greatest decline occurs under the inflexible standard, which is 50 percent greater than the decline under cap and trade with an auction, and 85 percent greater than the decline under a flexible standard. There is almost no change in generation under cap and trade with allocation to LDCs.

The decline in coal generation is 83 percent greater under the inflexible standard than under the flexible one, and the difference is proportional to the change in overall generation. Under both policies there is an increase in gas-fired generation that offsets 63 percent (for the inflexible standard) and 69 percent (for the flexible standard) of the decline in coal generation.

However the relative change in generation by fuel type is not proportional when comparing to the cap and trade policies. The decline in coal-fired generation is roughly one-third of what obtains under the flexible standard, and much smaller still compared to the inflexible standard. Conversely, the increase in natural gas generation is much smaller also. The reason is related to the change in capacity.

The change in coal-fired capacity is the greatest under the inflexible standard, and is six times greater than occurs under the flexible standard and roughly 8 times greater than occurs under the cap and trade policies. The capacity change is relatively greater than the generation change from coal-fired plants because the inflexible standard forces retirement from capacity that

does not generate very much. To varying degrees, there is an offsetting increase in natural gas capacity and a much smaller increase in renewable generation capacity (not shown in Table 2).

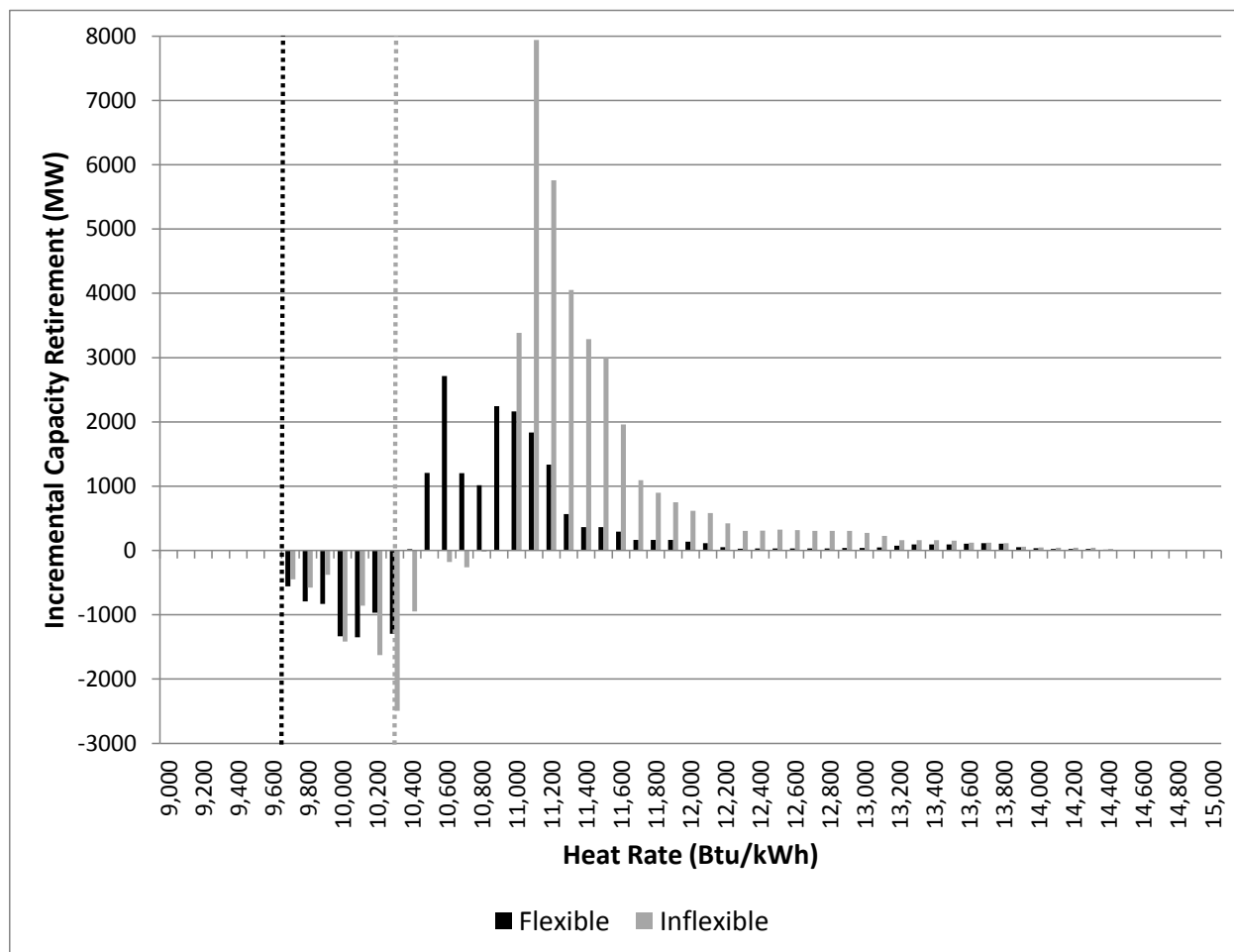
The pattern of retirements varies substantially between the flexible (darker bars) and inflexible (lighter bars) standards, as illustrated in Figure 1. The horizontal axis displays heat rates in the data year (2008) before any investments have taken place, and the vertical axis displays incremental capacity retirements that occur in addition to those that occur in the baseline under each policy. The vertical dashed lines represent the benchmarks under the flexible standard (darker line on the left) and the inflexible standard (lighter line on the right). Reading from the left, one sees that there is less retirement among the relatively efficient units under both policies than occurs under the baseline. This occurs because electricity price increases under both policies, providing greater revenue and increasing going-forward profitability.

At about 10,400 Btu/kWh, one begins to observe net retirements under the flexible standard but not under the inflexible standard. In this range the profitability due to the greater change in electricity price under the inflexible standard is influential, and plants that don't have to retire do not do so. Under the flexible standard the cost of GECOs for plants operating at a heat rate that is greater than the benchmark of 9,657 Btu/kWh also is influential in promoting greater retirement. At 11,000 Btu/kWh important levels of retirement begin under the inflexible standard as it becomes increasingly difficult for these plants to attain the standard. All plants with an initial heat rate greater than approximately 11,000 Btu/kWh will necessarily retire because they do not have the technical opportunity to achieve the standard.

### **5.3 Investments**

Table 2 reports the average heat rate that is obtained under the various policies. The lowest heat rate is obtained under the flexible policy because even relatively efficient plants retain a strong incentive to reduce heat rates where there are opportunities to do so. In contrast, under the inflexible standard if a plant is in attainment of the standard its incentives to make additional investments are relatively weak and largely equivalent to those that occur under the baseline. The cap and trade policies result in the greatest heat rates and the least improvement in average efficiency because these policies do not target this specific margin of performance, but instead harvest emissions reductions from many channels. Recall the emissions reductions required under the two cap-and-trade policies is applied to the entire electricity sector, so substitution from coal to natural gas generation plays a major role in these cases. As a consequence, although the cap and trade approaches would be expected to be more efficient overall, they are less effective at achieving improvements in plant performance.

Figure 1. Incremental Capacity Retirements in 2020 by Heat Rate



The flexible standard yields investments of \$2,933 million in energy efficiency, over 8 times more than under the inflexible standard by 2020. The GECO price begins to climb sharply at that point, jumping from \$4.80/Btu in 2018 to \$26.4/Btu in 2020. This jump occurs because at that juncture 95 percent of potential efficiency improvements have been made.

### 5.4 Costs

With the exception of the inflexible standard, three of the policies generate prices associated with new assets. Cap and trade policies introduce tradable emissions allowances and the flexible performance standard yields a price on generation efficiency credit offsets (GECOs) equal to \$26.4/MMBtu in 2020.

In 2020 the benchmark level under the flexible standard is 9,657 Btu/kWh. Plants that are more efficient than this standard earn a reward; plants that are less efficient incur a penalty. The

decisions of individual plants about investment in energy efficiency and their level of continued operation will vary depending on regional differences in fuel costs and the cost of allowances for other pollutants (sulfur dioxide and nitrogen oxides), electricity prices and equilibrium changes in capacity and generation. To consider a representative example, consider a plant that has a heat rate of 10,000 Btu/kWh in the baseline but makes investments under the flexible policy to reduce its heat rate to 9,600 Btu/kWh. Then for every kWh it generates it earns 9,657 GECOs (equal to the benchmark) but has to surrender only 9,600 GECOs for compliance. In other words, this relatively efficient plant earns 57 GECOs on net for each kWh of operation, and at the equilibrium GECO price of \$26.4/MMBtu, this totals to \$1.5 per MWh<sup>16</sup> as a reward for relatively efficient operation. In contrast, consider a plant that starts out with a heat rate of 10,500 Btu/kWh in the baseline and under the flexible policy chooses to make investments to reduce its heat rate to 10,000 Btu/kWh. At the benchmark of 9,657 Btu/kWh this plant must purchase 343 GECOs for every kWh of operation. The total GECO cost for this plant is \$9.1 per MWh, which serves a penalty for relatively inefficient operation.

Even in the baseline, firms already have an incentive to save on fuel costs, so it may be surprising that a flexible performance standard would be able to engender substantial additional improvements in efficiency beyond those that would already occur. The flexible standard does so because it introduces a potent signal at the margin that is substantially greater than the marginal signal to improve efficiency associated with fuel costs. At a GECO price of \$26.4/Btu, the marginal incentive to improve efficiency is approximately 13 times greater from the flexible standard than is the signal from fuel cost savings alone, and this incentive applies to relatively efficient facilities as well as inefficient ones.

Nonetheless, for a relatively inefficient facility the GECO costs can accumulate to a substantial amount. At a heat rate of 10,400 Btu/kWh a facility will incur GECO costs that are about equal in magnitude to its total fuel costs, and at a rate of 11,300 Btu/kWh it will incur costs that are two times greater than its total fuel costs, even after it may have incurred costs to make efficiency investments. From the perspective of the plant operator, these additional costs may seem exceptional, and may be viewed as a disadvantage compared to an inflexible standard that would not incur GECO costs. However, from a system perspective the flexible standard has an

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<sup>16</sup> Each GECO measures a difference in heat rate, so GECOs are in units of Btu/kWh. The net GECO generation of a plant can be multiplied by the GECO price (in \$/Btu) to yield a net subsidy or cost per kWh of generation. In this example,  $57 \text{ Btu/kWh} * \$2.64 * 10^{-5} / \text{Btu} = \$0.0015 / \text{kWh}$ , which is equivalent to \$1.5/MWh.

advantage that it would allow a plant with heat rates of 11,300 Btu/kWh to remain in operation if it chose to do so, even after considering the incremental GECO-related costs. Such a facility might remain in service because of its idiosyncratic value to the electricity grid, which may depend on its unique location or type of ancillary service it provides. An inflexible standard would not allow such a facility to survive, despite its great value, because it strictly violates the allowable level of performance.

The average equilibrium delivered cost of coal varies only under the inflexible standard. This outcome results from a change in the type of coal used. The substantial retirement of relatively inefficient facilities lowers the demand for emissions allowances and also their price, leading to a substitution to greater use of bituminous coal and away from low-sulfur subbituminous coal. The geographic distribution of surviving facilities also contributes to the increase in the average delivered cost of coal. The national average equilibrium delivered cost of natural gas closely mirrors the change in generation with natural gas.

### **5.5 Cost Effectiveness**

Total cost (billion dollars per year) of the policies is decomposed into changes in consumer expenditures, producer surplus and revenues to the government. Table 2 shows the change in each cost category under each policy before adjusting for changes in the level of consumption. The change in consumer cost is the change in total expenditure on electricity. The change in producer cost is the change in producer surplus (profits). The costs of the policy are either passed on to consumers or absorbed in a change in producer profits. To this we add the change in costs to government. To calculate cost effectiveness, we first find the total cost of generating electricity in each policy and then divide this cost by the total amount of electricity consumed. This gives the average cost of a MWh of consumed electricity under each policy. This cost is compared to the cost in the baseline scenario, and the additional per-MWh cost of each policy is reported in Table 2.

The largest change in consumer costs is an increase of \$7 billion per year that occurs under the inflexible standard, due to the increase in electricity prices. The cap and trade policy with allocation to LDCs reduces consumer costs due to declining electricity prices, while the other policies increase electricity prices and consequently increase consumer costs. The largest change in producer cost is a decline in cost (increase in profits) of \$2.3 billion per year also under the inflexible standard. This change is driven by the change in retail electricity prices; however, the benefit of the price change accrues to the industry as a whole and does not signal an increase in profits from owners of coal-fired plants. The industry also realizes a negative cost



under the flexible standard, but it is much less than in the inflexible case. In contrast the cap and trade policies lead to increases in producer costs. The changes in government costs are negative and large due to revenues from the auction in one case and include small changes in tax revenues otherwise.

Our measure of cost effectiveness is the change in the average per-MWh cost of electricity (\$/MWh), noting that the emissions reductions are constant across the policies. The inflexible standard results in a percent change in industry costs per MWh of 8.4 percent from baseline, roughly three times as great as the increased cost under the flexible standard. The costs under the cap and trade with LDC allocation are lowest, but this measure masks costs that are imposed on other parts of the economy because of the higher allowance price that results compared to cap and trade with an auction.

## 6 Conclusions

This research investigates the economic opportunity and potential advantage of introducing flexibility in the CO<sub>2</sub> emissions reduction activities and compliance responsibilities for stationary sources under the Clean Air Act. We model these emissions reductions activities as improvement in the operating efficiency (as opposed to the emissions rate) of coal-fired power plants. We compare four leading approaches to climate policy in the electricity sector using a detailed simulation model, where the primary mode of compliance is investment at plants to improve their operating performance. The policies we examine include a flexible performance standard that allowed trading among sources so that the standard was achieved in the aggregate and an inflexible standard that required every individual source to be in compliance. We compare these with two versions of cap and trade. All policies are calibrated to achieve equal emissions reductions.

The flexible standard results in an increase of about 1.3 percent in electricity price compared to the baseline. In contrast, the change in electricity price under an inflexible standard is 3.3 percent of baseline levels, substantially more than would occur even under cap and trade with an auction. The inflexible standard also leads to the greatest decline in coal-fired generation, about 85 percent greater than would occur under a flexible standard. Conversely, the flexible standard leads to much greater investment to improve the operating efficiency of existing plants. These investments coupled with the flexibility of this approach explain the relative profitability of existing coal-plants under the flexible standard compared to an inflexible approach. The flexible standard leads to total cost that is just 29 percent of that under the inflexible approach.

We also find the flexible policy affects decisions about the continued operation of individual plants. The flexible standard allows for continued operation of some relatively inefficient plants that have relatively high economic value within the electricity system, while the inflexible standard forces the retirement of those plants.

One important caveat is that the EPA may propose and states may promulgate alternative policies that result in different emissions reductions for different categories of plants, rather than for all coal-fired units as we have modeled it. For example, subcategorization by unit type could lead to different results.

Nonetheless, the EPA is expected to promulgate rules affecting existing stationary sources including coal fired power plants in 2012. Legal analysis indicates the agency has substantial authority to implement flexibility in compliance with these rules. This research indicates that under the performance standard design modeled here the economic advantages of this approach would be substantial, reducing the change in electricity prices by 60 percent while also reducing the total costs of the standards by over two-thirds compared to an inflexible standard.

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## Appendix: Emission Rate versus Heat Rate Standards

One dimension that affects the design of performance standards are whether they should be based on emissions rates or heat rates. A percentage improvement in the average emissions rate is nearly equivalent to a percentage improvement in the average heat rate. The difference stems from slight variation in carbon per Btu in varieties of coals. However, a percentage improvement in the average emissions rate (or equivalently in the average heat rate) does not necessarily lead to an equal percentage reduction in total emissions. In fact, a policy that reduced the average emissions rate by 5 percent could reduce total emissions by much more than 5 percent, depending on its effect on the generation and capacity mix.

To illustrate, imagine a fleet of plants with heat rates of 8, 9, 10, 11 and 12 (thousand Btu/kWh). If these plants all had equal utilization rates, and emissions were a straight-forward multiple ( $E$ ) of heat rate and utilization, then in the baseline emissions equal  $50E$ . Retirement of the least efficient plant (12) would drop the average heat rate from 10 to 9.5 (an improvement of 5 percent) but it would reduce emissions to  $38E$  (a reduction of 24 percent). Note further, this is not the same as an inflexible standard that required a 5 percent improvement in the heat rate of every plant, which would lead to a new average heat rate of 9.5, and emissions of  $45E$ .

Table A1 reports the changes that occur by using a flexible and inflexible standard to achieve equivalent average reductions in heat rate. The results for the flexible standard are the same as in Table 2; but in Table A1 the emissions changes differ between these two policies. The inflexible standard requiring an equivalent average heat rate leads to an emissions decrease that is 2.8 times greater, but an increase in electricity price 7.5 times greater. Substantially greater reductions in coal generation and capacity also result, along with large increases in the use of natural gas. The inflexible standard does not yield substantial investments in efficiency improvements at existing facilities. The total cost is over 8 times greater than the flexible standard. Divided by the change in CO<sub>2</sub> emissions this reflects a change in industry costs per ton reduced that is 2.7 times that achieved under the flexible standard.

**Table A1. Comparison of Scenarios Achieving Equal Average Heat Rate Improvement<sup>1</sup>**

Year 2020 Values in 2008 dollars	<b>Flexible Compliance</b>	<b>Inflexible Standard</b>
<b>Change in Elec. Price</b> (\$/MWh)	1.16 <i>1.3%</i>	7.07 <i>8.1%</i>
<b>Change in Generation<sup>2</sup></b> (BkWh)	-40 <i>-0.9%</i>	-181 <i>-4.1%</i>
Coal	-114 <i>-5.9%</i>	-619 <i>-32.1%</i>
Gas	79 <i>7.8%</i>	419 <i>41.7%</i>
<b>Change in Capacity<sup>2</sup></b> (GW)	-0.6 <i>-0.1%</i>	-17.5 <i>-1.8%</i>
Coal	-5.5 <i>-2.0%</i>	-92.6 <i>-33.7%</i>
Gas	6.2 <i>1.5%</i>	73.3 <i>17.2%</i>
<b>Avg. Coal Plant Heat Rate</b> (Btu/kWh)	9,657	9,653
<b>Avg. Effic. Improve.</b> (Btu/kWh)	525 <i>5.2%</i>	529 <i>5.2%</i>
<b>Efficiency Investments</b> (M\$) <sup>3</sup>	2,933	418
<b>GECO Price</b> (\$/MMBtu)	26.4	
<b>CO<sub>2</sub> Price</b> (\$/ton)		
<b>Cost of Coal</b> (\$/MMBtu)	1.95	1.96
<b>Cost of Gas</b> (\$/MMBtu)	5.42	5.79
<b>Change in Total Cost</b> (B\$/year)	1.4	11.4
Consumer Cost	1.9	15.9
Producer Cost	-0.4	-5.1
Cost to Government	-0.2	0.6
<b>Change in Cost / MWh</b> (\$/MWh)	1.9 <i>2.8%</i>	13.9 <i>20.1%</i>
<b>Change CO<sub>2</sub> Emissions</b> (M tons)	141	400
<b>Change in Cost /MWh /ton</b> (\$/MWh/Mtons)	0.13	0.35

1) CO<sub>2</sub> emissions reductions across differ between these two scenarios.

2) Change in total generation and capacity include changes in addition to coal and gas plants.

3) Cost of efficiency improvements include investments in capital and changes operating procedures.