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CO_2 Allowance Allocation in the Regional Greenhouse Gas Initiative and the Effect on Electricity Investors

Dallas Burtraw, Danny Kahn, and Karen Palmer

1616 P St. NW
Washington, DC 20036
202-328-5000 www.rff.org

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Abstract

The Regional Greenhouse Gas Initiative (RGGI) is an effort by nine Northeast and Mid-Atlantic states to develop a regional, mandatory, market-based cap-and-trade program to reduce greenhouse gas (GHG) emissions from the electricity sector. The initiative is expected to lead to an increase in the price of electricity in the RGGI region and beyond. The implications of these changes for the value of electricity-generating assets and the market value of the firms that own them depends on the initial allocation of carbon dioxide allowances, the composition of generating assets owned by the firm, and the locations of those assets. Changes in asset values inside the RGGI region may be positive or negative, whereas changes outside of the RGGI region are almost always positive but nonetheless vary greatly. Viewing changes at the firm level aggregates and moderates both positive and negative effects on market value compared with what would be observed by looking at changes at individual facilities. Nonetheless, a particular firm's portfolio of assets is unlikely to reflect the overall composition of assets in the industry as a whole, and some firms are likely to do substantially better or worse than the industry average.

Key Words: emissions trading, allowance allocations, electricity, air pollution, auction, grandfathering, generation-performance standard, output-based allocation, cost-effectiveness, greenhouse gases, climate change, global warming, carbon dioxide, asset value

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1. Introduction

The Regional Greenhouse Gas Initiative (RGGI) is an effort by nine Northeast and Mid-Atlantic States to develop a regional, mandatory, market-based cap-and-trade program to reduce greenhouse gas (GHG) emissions. The effort was formally initiated in April 2003 when Gov. George Pataki of New York sent letters to governors of the Northeast and Mid-Atlantic states. Each of the nine participating states (Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) has assigned staff to a working group that is charged with developing a proposal in the form of a model rule by the end of 2005. Initially, the program will address carbon dioxide (CO_2) emissions from the electric power sector. If successful, the program could serve as a model for a national cap-and-trade program for GHG emissions.

The RGGI program is expected to affect electricity consumers by causing an increase in electricity prices. Higher electricity prices would likely result in higher revenues for industry, but increased revenues could be offset by higher costs. In addition, the program is likely to lead to increased imports of power into the RGGI region from power plants that are not covered under the program.

How emission allowances are initially distributed will have a direct effect on the relative well-being of consumers and producers and on the relative profitability of different types of producers. Three approaches to initial distribution have been considered in other regulatory contexts. One is to distribute allowances on the basis of historic measures of electricity generation; this approach, often called *grandfathering,* distributes allowances without charge to incumbents in the industry. A second approach is similar, but with regular updating of the

* Burtraw (burtraw@rff.org) and Palmer (palmer@rff.org) are senior fellows and Kahn (kahn@rff.org) is a research assistant in the Quality of the Environment Division at Resources for the Future (RFF). This research was performed under grants from the Hewlett Foundation and from the New York Community Trust.

calculation underlying the allowance distribution on the basis of current- or recent-year data. Like historic allocation, an updating approach distributes allowances free of charge and also could distribute according to various measures, such as share of electricity generation, emissions, or heat input (a measure related to fuel use) at a facility. A third approach is to sell allowances through an auction, directly or indirectly. For example, allowances could be sold by the government or freely distributed to third parties (e.g., energy consumers or their trustees) that would then sell allowances through an auction.

In this paper, we analyze the effects of these three allocation mechanisms using a detailed simulation model of the electricity sector. We find that the initial distribution of allowances has an effect on electricity price, consumption, and the mix of technologies used to generate electricity, and these changes affect the asset values of individual facilities. The value of coal-fired generation assets in the RGGI region decreases under all approaches except historic and decreases the most under updating. Gas-fired generation decreases under historic and auction approaches but increases substantially under updating.

The effect on investors—that is, the shareholders of firms—depends on the portfolio of generation assets held by a firm. The group of firms directly affected by RGGI includes generating firms that do business exclusively within the RGGI region, but also includes several firms within the region that own assets outside the RGGI region. We calculate changes in the values of generation assets within RGGI, outside RGGI, and for the portfolio of generating assets as a whole owned by firms operating in the RGGI region. Modeling indicates that an unintended consequence of the RGGI policy would be leakage of electricity generation, emissions, or both to outside of the RGGI region. Moreover, where there is leakage, there is profit. Facilities outside the RGGI region that expand generation to export power to the RGGI region would earn a profit from doing so. In some cases, profits earned by a firm outside the RGGI region offset losses incurred by the same firm inside the RGGI region.

Viewing changes in the portfolio of generation assets at the firm level aggregates and moderates the positive and negative effects of allocation on market value compared with what would be observed at individual facilities. However, a particular firm's portfolio of assets is unlikely to reflect the overall composition of assets in the industry as a whole, and some firms are likely to do substantially better or worse than the industry average.

We find that the effect of allocation on shareholders—for example, the effect on the market value of a firm—depends significantly on the firm's portfolio of generation assets. Effects outside of the RGGI region are important because they nearly always increase the value of firm assets. Moreover, a large portion of the change outside the RGGI region comes from increased prices of electricity generated outside the RGGI region and paid by non-RGGI customers. In general, firms are better off under a RGGI policy with a historic approach to allocation than with no policy. Under an auction, half of the RGGI firms see asset values fall, and half see a gain. Overall losses to firms are greatest under an updating approach.

2. Methodology and Scenarios

Many papers have analyzed approaches to the initial distribution of emission allowances and the efficiency and distributional consequences of those approaches (Bovenberg and Goulder 1996, Goulder et al. 1997, Goulder et al. 1999, Parry et al. 1999, Smith et al. 2002). With regard to distributional impacts, Burtraw et al. (2002) and Bovenberg and Goulder (2001) find that, in the case of nationwide CO_2 regulation, the free allocation of emission allowances can dramatically overcompensate the electricity industry in the aggregate, although different parts of the industry are affected differently. Recent analysis of the CO_2 emission trading system in Europe that began in 2005 has reached a similar conclusion (Sijm et al. 2005, U.K. House of Commons 2005). Using a simple model with fixed capacity and fixed demand in the RGGI program, the Center for Energy, Economic & Environmental Policy (2005) finds that, compared with no policy, all three approaches to allocation—historic, auction, and updating—would increase profitability for the electricity sector as a whole, and the historic approach results in the greatest increase in profits.

A central issue is the degree to which electricity producers pass on (in electricity prices) resource and allowance costs in an emission-trading program. It varies with the presence or absence of price regulation and with the technology that sets marginal cost in competitive regions. In much of the country, electricity prices are set through cost-of-service regulations. In those states, the original acquisition cost of allowances would be included in the total cost basis, and allowance and resource costs would be recovered in the electricity price. However, in most of the RGGI region and neighboring states,[1] the competitive power market sets electricity prices. In these states, the allowance and resource costs are indirectly passed on in electricity prices. The market price of electricity is determined by the technology of the facility that sets the marginal cost in the power market. The change in electricity price may over- or underrepresent the change

[1] Vermont has not restructured its electricity sector and still relies on cost-of-service regulation to set electricity price.

in costs for other facilities and other technologies. Analyzing these effects involves identifying the marginal generation technology at various points in time, the costs that determine the market price of electricity, and the cost of other generators through use of a simulation model.

To carry out our analysis, we use a detailed simulation model maintained by Resources for the Future. The scenarios we model make certain assumptions about the potential design of a RGGI policy, but these assumptions are not intended to mirror precisely the design of specific policy proposals under consideration or to anticipate the policy outcome of the RGGI process. However, they do retain the key elements of proposals that have received attention in the ongoing RGGI stakeholder process. In all of the policy cases we model, the annual CO_2 emission target is set by calculating a 20 percent decline from 2008 baseline emission levels in the RGGI region, with the emission reduction to be phased in linearly between 2008 and 2025.

RGGI covers nine states, encompassing the New England and New York power regions and a large portion of the Mid-Atlantic region (MAAC) contained in New Jersey and Delaware. We analyze three approaches to the distribution of emission allowances: historic (to emitters on the basis of historic generation in 1999), auction, and updating (to emitters on the basis of recent-year generation with a 2-year lag).[2]

One important issue in determining the effect of the program on asset values is the role of long-term contracts for electric power. The model assumes competitive electricity spot markets set the price for nearly all generation in the RGGI region and in the two neighboring regions (Maryland and the eastern part of Pennsylvania in NERC's MAAC region, and all of NERC's East Central Area Reliability Coordination Agreement [ECAR] region, which includes Indiana, Kentucky, Michigan, Ohio, part of western Pennsylvania, and West Virginia). This assumption means that to the extent that the RGGI cap-and-trade policy for CO_2 emissions raises the marginal costs of electricity generation, all of that increase in marginal cost will flow through to prices paid by electricity consumers. However, a generating unit selling its generation under a long-term contract may not be able to realize an increase in revenues associated with the regulation. Wilson et al. estimate that in 2010, roughly 13 percent of all electricity sold in the RGGI region will be under long-term contracts. As a result, the predicted model equilibrium may overestimate the change in retail electricity prices and therefore underestimate electricity

[2] See Burtraw, Palmer, and Kahn 2005 for details on the methodology, a discussion of a broader set of issues, and a more complete characterization of results (e.g., change in electricity price and the generation mix).

demand. But given the fact that most generation under long-term contracts is baseload hydroelectric and nuclear, long-term contracts will have little effect on the marginal costs of generation.

In calculating the asset values of generators, we account for hydroelectric power sold by the New York Power Authority and for nuclear generators in New York State and Vermont that are under long-term contract. Because of a lack of data, however, we are unable to explicitly incorporate other long-term contracts, including cogeneration. As a result, we may overestimate the value of generation assets for this class of facilities. Wilson et al. suggest that in 2010, this class may account for 3 percent of total generation in the region.

3. Aggregate Results for the Allocation Scenarios

The level of aggregation matters when estimating the effect of the RGGI policy on asset values because some facilities lose value and others gain value. Considered individually, the effect on asset values of facilities appears to vary greatly. However, when asset values are considered across the industry, the gains in some facilities offset losses at others. This approach would offer the most appropriate aggregation if it is assumed that large investors (e.g., pension funds and mutual funds) have the opportunity to build a portfolio of investments that balance the risks of holding any one firm.

We begin by looking at the effect of RGGI policy on the asset value of facilities by class of technology for the industry as a whole. In Section 4, we reexamine these changes at the firm level.

3.1. Generation and Price Results

The effects of the different CO_2 allocation approaches on asset values depend importantly on changes in electricity price, the price of emission allowances, and the amount of output that generators produce. Table 1 summarizes the results for generators located within the RGGI region under the three different allocation approaches and under the baseline (no policy). These results show that electricity price increases under all three approaches. Consumers prefer updating because it leads to the lowest electricity price of the three policy approaches. Similarly, in each case, total generation within the RGGI region falls relative to the baseline, but it falls the least—by less than one-half as much—under updating than under the other approaches. This attribute of updating follows from the incentive to increase electricity generation to earn a larger award of emission allowances.

Table 1. Overview of Simulation Results for the RGGI Region, by Allowance Allocation Method, 2025[a]

Data	*Baseline*	*Historic (Generation)*	*Auction*	*Updating (Recent Generation)*
Average electricity price (1999$/MWh)	$103.4	$107.1	$107.2	$103.9
TOTAL generation (billion kWh)	393	348	348	371
Coal	73	48	48	23
Gas	130	115	116	173
Nuclear	107	108	108	106
Renewable	34	40	40	32
TOTAL new capacity[b] (GW)	28	31	31	33
Gas	23	24	24	28
Renewable	5	6	6	5
CO_2 price (1999$/ton)	n/a	$18.1	$18.3	$35.3
Emissions				
CO_2 (million tons)	147	100	99	98
NO_x (thousand tons)	118	70	70	41
SO_2 (thousand tons)	193	101	107	36
Mercury (tons)	1.2	0.8	0.8	0.3

[a] The modeled scenario does not match any specific proposal that is part of RGGI.

[b] Numbers may not sum because of rounding.

The mix of fuels used to generate electricity also varies across allocation approaches. Coal-fired generation falls under all approaches but falls the most under updating. The greater decline in coal under updating—to one-half the level of the other approaches—results from decreases in the relative cost of natural gas–fired generation. In somewhat opposing fashion, gas-fired generation falls under the historic and auction approaches but increases substantially under updating. The emission rates for natural gas are below the average for emitting sources, whereas those for coal are above average. Consequently, natural gas is the preferred fuel for responding to the incentive to expand production under updating. Generation with natural gas increases by 33 percent under updating relative to the baseline but falls by about 12 percent under the other approaches. The price of CO_2 emission allowances is twice as high in the updating case because of the overwhelming incentive to increase gas-fired generation, which more than compensates for the decreased average emissions from natural gas sources. CO_2 emissions in 2025 are comparable in all scenarios, representing a 32 percent reduction from the baseline. Emissions of other pollutants also are affected by efforts to control CO_2.

3.2. Effects in RGGI by Generation Type

The effect of allocation on asset values varies significantly across types of generators and reflects changes in revenues and costs. To illustrate the financial changes, we begin by presenting a simplified version of the profits of an individual facility for a single period with a profit equation where $\text{Profit} = QP - QC + A$. In this equation, Q represents the quantity of sales, P represents electricity price, C represents the costs of generation and reserve services, and A represents the market value of allowances distributed for free (including sulfur dioxide [SO_2], nitrogen oxides [NO_x], and CO_2 allowances). Allowance value is determined by the market price of emission allowances because market price represents their opportunity cost compared with the option of selling the allowances in the market.

A first-order estimate of the change in profits is represented by the total derivative of the profit equation:

$$\Delta\text{Profit} = Q\Delta P + \Delta Q\left(P\right) - Q\Delta C - \Delta Q\left(C\right) + \Delta A \qquad (1)$$

where Δ denotes changes stemming from the introduction of the RGGI policy. The first term represents the change in electricity price, which is determined by the change in the cost not at this facility but at the marginal generation facility. The third term represents the change in cost (allowance and resource costs) at this facility. Differences in heat rates and other performance characteristics among facilities suggest a distribution of effects even within a given class of technology or fuel. The costs of coal and natural gas fuel also change in response to changes in the use of these fuels. The fifth term is the value of the allocation. Although initiation of the RGGI program potentially institutes a new allocation in CO_2 emission allowances, there is also a change (captured in the model) in the value of the allocation for programs such as those for trading SO_2 and NO_x emissions allowances because of changes in their market prices.

Changes in the quantity of generation and its effects on revenue and cost are represented by the second and fourth terms in equation 1. These quantities depend on changes in both relative costs of generation among different facilities and demand in response to the change in electricity price.

The model aggregates these effects using a present discounted value calculation of the changes in cash flow and net revenue over time for each facility. We find that when all types of assets are aggregated, the net present value (NPV) of generation assets in the RGGI region increases substantially under historic allocation and decreases slightly under an auction. Producers realize the lowest value of existing generation assets under updating. Table 2 summarizes the NPV of generation assets in the baseline scenario and the change in value under each approach. The remarkable performance under a historic approach to allocation stems from the creation of wealth associated with emission allowances, and the distribution of wealth to incumbent facilities. The opportunity cost of emission allowances is indirectly reflected in electricity price because price is set by the marginal generator. Hence, if the marginal generator is a gas turbine, then the opportunity cost of emission allowances used to operate the turbine reflects the increment to electricity price in a competitive electricity market. Several factors help determine the degree to which the opportunity cost of emission allowances is reflected in price, including the long-lived nature of capital investments, distribution of capital intensity, emission intensity and fuel intensity of different technologies for generating electricity, and variation in electricity demand by time of day. The factors work in parallel for historic and auction approaches in determining how RGGI policy will affect electricity price and revenues. That is, the change in electricity price is almost identical because electricity price is based on marginal opportunity cost regardless of how the emission allowances are distributed initially. Under the historic approach, this value is assigned to incumbent facilities and more than offsets the change in cost for electricity generation. Under the auction approach, this value is assigned to the government or some other entity, but even in this case, the change in electricity price nearly compensates for the change in the cost of electricity generation.

Meanwhile, in the aggregate, the value of generation assets under the updating approach declines over three times more than under an auction. This results because the model predicts that an updating approach significantly reduces the change in electricity price that would occur under a historic or auction approach (Beamon et al. 2001, Burtraw et al. 2001, 2002, Fischer 2003, Fischer and Fox 2004). Updating provides an incentive for generators to expand electricity generation in order to earn a share of the valuable emission allowances. The increase in generation provides pressure to lower electricity price, which significantly offsets the increase in electricity price associated with reducing emissions.

We find that gas-fired generation facilities generally gain value relative to the baseline under historic and updating approaches and lose value slightly under an auction. Table 2 indicates a negative value for gas-fired assets in the baseline. This measure includes a cost of capital for payment on capital investments. In cases where investments have proven unprofitable, the calculation of asset value is negative, but facilities generally continue to operate because revenues remain greater than variable costs. In some cases, debt service has been written down for accounting purposes, and our baseline measure therefore would not correspond to an accounting measure. However, this practice does not have a bearing on our calculation of the change in asset value from baseline under various policy scenarios. Moreover, under all approaches, the asset value increases for gas-fired capacity that was in existence as of 1999 but not for the substantial fleet of gas-fired capacity built since 1999.[3]

Coal-fired generation assets just break even under the historic approach and do the worst under updating, losing substantial value relative to the baseline scenario. Existing nuclear facilities not under long-term contract benefit substantially under a historic or auction approach compared with the baseline. However, these assets lose value under updating, which has a lower

Table 2. Baseline Net Present Value (NPV) of Generation Assets and Change from Baseline, by Generation Type and Allowance Allocation Method (1999$/kW)

		Change from Baseline		
	Baseline (NPV)	*Historic (Generation)*	*Auction*	*Updating (Recent Generation)*
RGGI region				
Gas	–273	54	–13	45
Coal	434	8	–185	–240
Nuclear	611	67	55	–51
Average ALL[a]	164	60	–13	–45
Maryland and Pennsylvania[b]				
Gas	–255	6	12	12
Coal	364	50	–185	24
Nuclear	653	51	51	20
Average ALL[a]	229	23	26	8

[a] Includes all generation capacity including types not listed separately.

[b] Includes the portion of Pennsylvania within NERC's MAAC region but outside the RGGI region.

[3] See Table 5 in Burtraw et al. (2005).

electricity price than historic and auction approaches. Updating also leads to lower variable costs for gas units that qualify for allowances, thereby pushing some incremental nuclear generation further up the dispatch schedule and potentially reducing nuclear generation. According to variations of updating analyzed by Burtraw et al. (2005), nuclear units do substantially better when they qualify for a share of the allocation of emission allowances.

3.3. Industry Profits Selling Power into RGGI

Table 2 indicates that in Maryland and the part of Pennsylvania that together constitute the portion of NERC's MAAC region that lies outside the RGGI region, the change in the NPV of generation is positive for all types of assets. This result follows from the increased sales supplied to the RGGI region and from the increase in electricity price that applies to every unit of production, including that delivered to native customers outside of the RGGI region.

The change in the value of generation assets outside the RGGI region is caused by two factors: Generators outside of the RGGI region will increase their revenues by exporting power to RGGI states and by charging their "native" (non-RGGI) electricity customers a higher price. The increase in demand for power to be exported to the RGGI region causes the marginal price of electricity generation to increase. Non-RGGI consumers therefore have to pay more for power they would have purchased even in the absence of the RGGI policy, which leads to a transfer of wealth from consumers to producers outside of the RGGI region.

To simplify the discussion, we ignore changes in costs and focus only on the changes in revenues that contribute to changes in asset values outside the RGGI region. The equation for revenue received by firms for power generated outside the RGGI region is

$$\text{Revenue} = Q_{\text{N}}\left(P_{\text{G}} + P_{\text{R}}\right) + Q_{\text{f}X} P_{\text{f}X} + Q_{\text{s}X} P_{\text{s}X} \qquad (2)$$

The revenue equation has several components. Customers pay the sum of the marginal cost of generation labeled as the generation price (P_{G}) and the marginal cost of reserve capacity (P_{R}). Sales of exported power yield additional revenue per megawatt-hour of electricity consumption by native customers (Q_{N}). The quantity of exported power under firm contract ($Q_{\text{f}X}$) yields revenues per megawatt-hour of $P_{\text{f}X}$ and sale in the spot market ($Q_{\text{s}X}$) yields revenues of $P_{\text{s}X}$. The spot market price for exported power is the average of the marginal generation price in the exporting and importing regions and hence is greater than the marginal generation price in the exporting region. Intra- and interregional transmission fees and line losses are also accounted for.

A first-order approximation of the change in revenue to firms can be represented by a total derivative of equation 2. Contracts for firm power are expected to remain unchanged.

$$\Delta\text{Revenue} = \Delta Q_{\text{N}}\left(P_{\text{G}} + P_{\text{R}}\right) + Q_{\text{N}}\Delta\left(P_{\text{G}} + P_{\text{R}}\right) + \Delta Q_{\text{s}X} P_{\text{s}X} + Q_{\text{s}X}\Delta P_{\text{s}X} \qquad (3)$$

The first two terms describe the change in revenues for sales to native customers. An increase in demand for generation due to an increase in power to the RGGI region increases marginal cost and electricity price paid by native customers. The sign of the first term is negative, because higher electricity price leads to lower native demand. The second term is positive, reflecting the increase in electricity price. Together these terms approximate the change in revenues from sales to native customers. The third and fourth terms reflect the change in revenues from the increase in exports: The third term describes an increase in the quantity of exports, and the fourth term describes the increase in the price of exported power.

Table 3 reports the change in 2025 revenues for all non-RGGI generators—including generators in the portion of NERC's MAAC region outside the RGGI region (Maryland and Pennsylvania) as well as in the ECAR region. The first pair of data columns represents the change in revenues from sales to native (non-RGGI) customers. The first column reflects the negative change in demand evaluated at the original price (in the absence of the policy), and the second reflects the change in price evaluated at the original quantity. The greatest change in revenues from non-RGGI customers occurs under updating, because this approach leads to more generation within the RGGI region and that increment in generation primarily comes from natural gas. This increment drives up the price of natural gas, which typically sets marginal cost and electricity price in neighboring regions.

Table 3. First-Order Estimates of Changes in Revenues (2025) for All Non-RGGI Generators (Maryland, Pennsylvania, and ECAR) (million 1999$)

Allowance Allocation Method	*From Native Customers due to Change in:*		*From Exported Power due to Change in:*	
	Quantity $\Delta Q_{\text{N}}\left(P_{\text{G}} + P_{\text{R}}\right)$	*Price* $Q_{\text{N}}\Delta\left(P_{\text{G}} + P_{\text{R}}\right)$	*Quantity* $\Delta Q_{\text{s}X} P_{\text{s}X}$	*Price* $Q_{\text{s}X}\Delta P_{\text{s}X}$
Historic	–88	611	707	112
Auction	–98	675	701	115
Updating	–121	786	131	73

The data in each row of the first two columns in Table 3 sum to represent the total change in revenues from native customers outside the RGGI region. Analogously, data in the second pair of columns sum to represent the total change in revenues from exported power to the RGGI region. Each approach to allocation is represented by one row in the table. Table 3 indicates a large share of the changes in revenues to firms owning assets in the bordering regions come from increased payments by native customers in these regions. For example, under historic allocation approximately $523 (–88 + 611) million in new revenue comes from native customers in the ECAR region and the non-RGGI portion of the MAAC region. About $819 (707 + 112) million in new revenues comes from power exports to the RGGI region.

One might suspect that the main beneficiaries among generators outside the RGGI region are those that ramp up production to meet increased RGGI demand. Table 3 indicates that this is not the case. The majority of benefits to producers outside the RGGI region flow through facilities that already are generating at full capacity, even in the absence of the RGGI policy. In Table 3 this is represented by the sum of columns labeled "Change in Price." These facilities realize an increase in revenues with little increase in cost. In contrast, facilities that increase generation to meet the increased demand for imported power in the RGGI region typically have greater costs than those already generating at full capacity. Hence, sources of new generation receive less benefit per megawatt-hour of generation than those who are already generating in the baseline scenario.

The overall change in the value of non-RGGI generation assets accounts for changes in fuel prices and investment patterns that affect generation costs. These changes are accounted for fully in the next section.

4. How Changes in Asset Values Affect Shareholders of Individual Firms

The changes in asset values affect shareholders through changes in the stock market value of the firm. The effect on shareholders offers compelling information for policy analysis because it not only accounts for the offsetting effects of facilities that gain and lose value but also measures those effects.

4.1. Assignment of Generation Assets to Firms

Our firm-level analysis focuses on the 23 firms providing at least 1,000,000 MWh of generation in the RGGI region in 1999. These 23 firms account for a combined total of 92 percent of total (nonhydroelectric and nonnuclear) generation within RGGI in 1999 and about 88 percent of total generation as forecasted by the model for 2008.[4] In this section we focus on changes in the value of assets held by these firms.

Changes in the value of specific assets are calculated as the change in the NPV of revenues minus costs for that facility over 2008–2030, measured in 1999$. We include facilities existing in 1999 plus new facilities planned and built through 2005. Generating assets are assigned to firms using information about plant ownership as of January 1, 2004, and the change in asset value for each facility is aggregated by ownership. This calculation is done for the three approaches to allocation, comparing each to the absence of the RGGI program.

Figure 1 illustrates changes in asset values within the RGGI region for each of these 23 firms. Firms are arrayed from A to W, roughly in order of decreasing total generation within the RGGI region in 1999. Analogous results for assets outside the RGGI region and within the entire four-region area are presented in Figures 2 and 3.

4.2. Assets inside the RGGI Region

As shown in Figure 1, every firm except one is better off under a historic allocation approach than with no policy, and almost every firm is best off under historic than under the other two approaches. Firm H, which loses value, holds generating assets that are primarily located in New York and New England, with a portfolio that includes no nonemitting generation. The other of the largest firms that does not fare very well is Firm E, whose generation is all in New England.

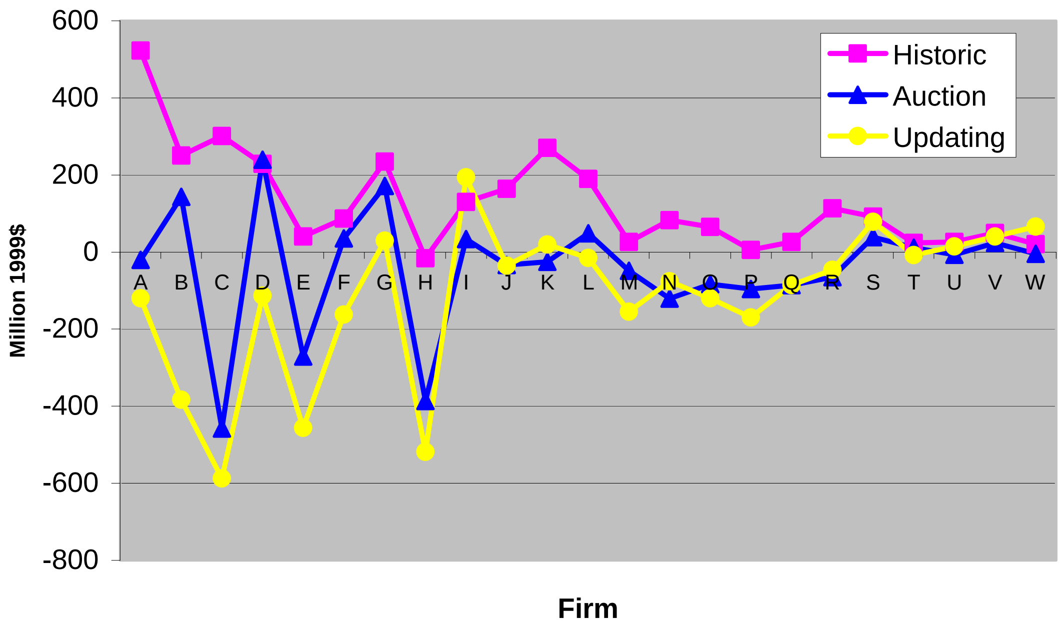
Six firms earn increases of more than $200 million in the value of their generation portfolio under historic allocation. The portfolios of these firms gaining value do not correspond to the portfolio for the region viewed in the aggregate. These firms contain 52 percent of the total generation from all 23 firms but 79 percent of the nuclear and 32 percent of the natural gas–fired generation. Viewed per megawatt-hour of generation in 1999, Firms J, K, and L gain the most under historic allocation. Each firm is predominantly composed of a different type of generation, indicating that many types of generation have the potential to gain under the historic approach. Only two firms (I and W) are better off under updating than under historic, and given the size of

[4] This calculation excludes the assets of the New York Power Authority and the three nuclear plants (Vermont Yankee, Nine Mile One, and Nine Mile Two) that have been identified elsewhere as having long-term contracts for the majority of their power output (Wilson, Palmer, and Burtraw 2005). These facilities accounted for 11 percent of overall generation in the region in 1999.

their portfolios, both firms are considerably better off than in the absence of the policy. Both firms are composed largely of natural gas and nonemitting generating assets and own no coal-fired generation within the RGGI region. For most firms, asset values decrease under a RGGI policy with an updating approach relative to the baseline case with no RGGI policy. Moreover, that decline in value is usually greater under updating than under an auction.

Under an auction, nine firms gain value relative to the absence of the RGGI policy, and one firm with almost all nonemitting capacity exhibits almost no difference between an auction and a historic approach. Three firms lose substantial value, although their loss is less under an auction than under updating; all have a large share of coal generation. The largest eight firms uniformly do worse under updating than under an auction, indicating that the increased revenues resulting from higher electricity prices under an auction outweigh the value of permits allocated with updating. In contrast, the smaller firms typically do similarly well under an updating or an auction approach. In the RGGI region, the overall loss in value under updating is 2.7 times that of under an auction.

Figure 1. Change in Firm-Level Asset Value within the RGGI Region



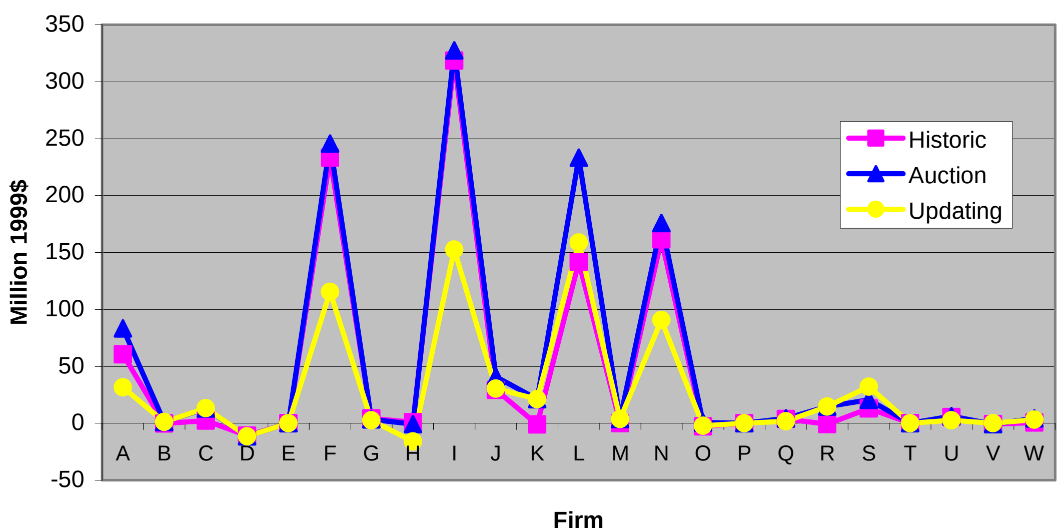
4.3. Assets outside RGGI

Table 3 indicates a substantial gain outside of the RGGI region; Figure 2 shows that the gain is not distributed uniformly among firms. Of the 23 firms, 15 own at least 50 MW of generating assets located in the two neighboring regions (the non-RGGI portion of NERC's MAAC and ECAR) that are included in the figure. Almost all of the 15 firms see the value of their assets outside the RGGI region increase under all three allocation approaches.

The effect on generation assets outside the RGGI region does not depend highly on the approach to allocation because these assets would not receive an allocation if allowances were awarded for free. Hence, the effects of historic and auction approaches are almost identical. Six firms realize substantial increases in the value of their non-RGGI assets regardless of the allocation approach. Four of these firms realize increases in total non-RGGI asset values of more than $150 million ($1999) under a historic or an auction approach. The slight differences between the auction and historic stem from the small effect of stranded asset charges associated with the move to competitive prices that remain in effect (even though they are being phased out) in the model.

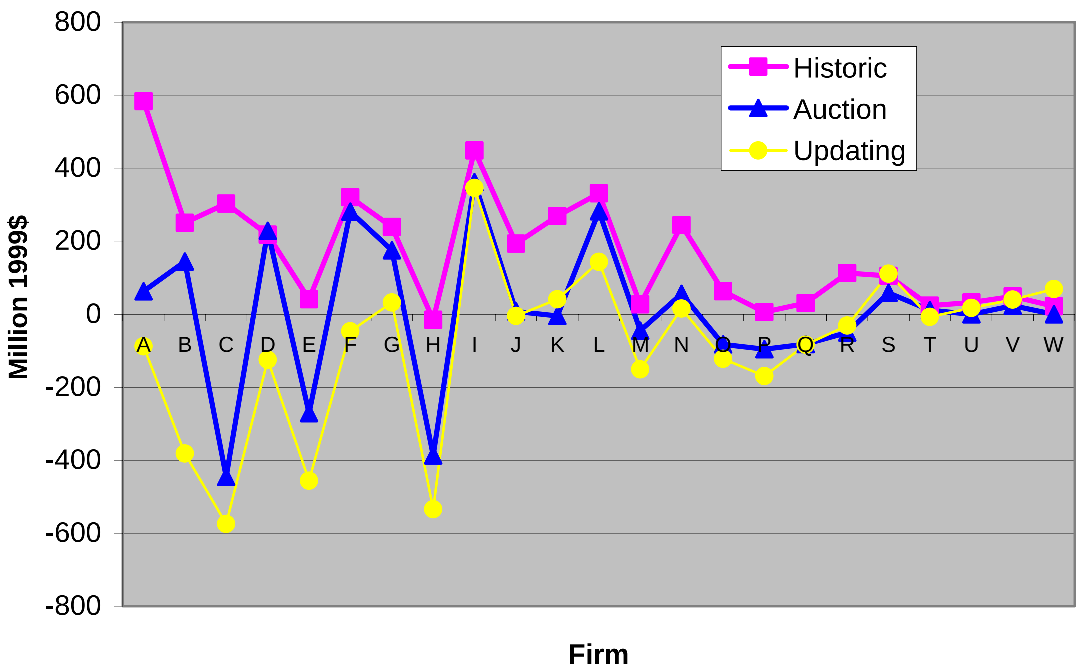
In contrast, several firms do considerably less well under updating than under a historic or an auction approach. Only three firms lose value from their non-RGGI assets, and those losses

Figure 2. Change in Firm-Level Asset Value Outside the RGGI Region



are small and occur under updating. The aggregate gain to all the firms from changes outside the RGGI region under updating is only about 65 percent of that under historic or an auction. The difference is largely due to the lower electricity prices and decreased imports into the RGGI region that occur under updating. These two factors significantly decrease the rents to firms' assets in the neighboring regions for two reasons. First, a lower electricity price implies a smaller increase in revenues, as illustrated in Table 3. Second, the updating approach provides incentives to expand electricity generation within RGGI, leading to a smaller increase in power imported to the RGGI region than under the other allocation approaches.

Figure 3. Change in Firm-Level Asset Value for Four-Region Area



4.4. Assets in the Combined Four-Region Area

The sum of changes in asset values among the 23 firms inside and outside the RGGI region is reported in Table 4. Under a historic approach, about 25 percent of the total increase in asset value occurs outside the region. Under an auction, the aggregate gain outside the region is greater in magnitude than the loss inside the region, leading to net gains across all firms in the four-region area. Under updating, gains outside the region erase about 25 percent of the losses within the region.

The combined effect of the change in the value of each firm's portfolio of assets inside and outside the RGGI region is illustrated in Figure 3. The relative positions of the three approaches to allocation across the four regions NERC sub-regions of New England, New York, MAAC and ECAR look similar to those inside the smaller RGGI region (Figure 1). The main difference between Figures 1 and 3 is that when the entire four-region area is included, firms do relatively better, sometimes substantially so, compared to the effects just within RGGI. In the four-region area, the historic approach yields positive changes in asset value for every firm except one and is preferred to the other approaches by every firm except one. Updating is less beneficial for assets outside the RGGI region and consequently fares less well when the entire four-region area is analyzed. For 17 of the 23 firms, including all of the largest firms, an auction approach is preferred to updating.

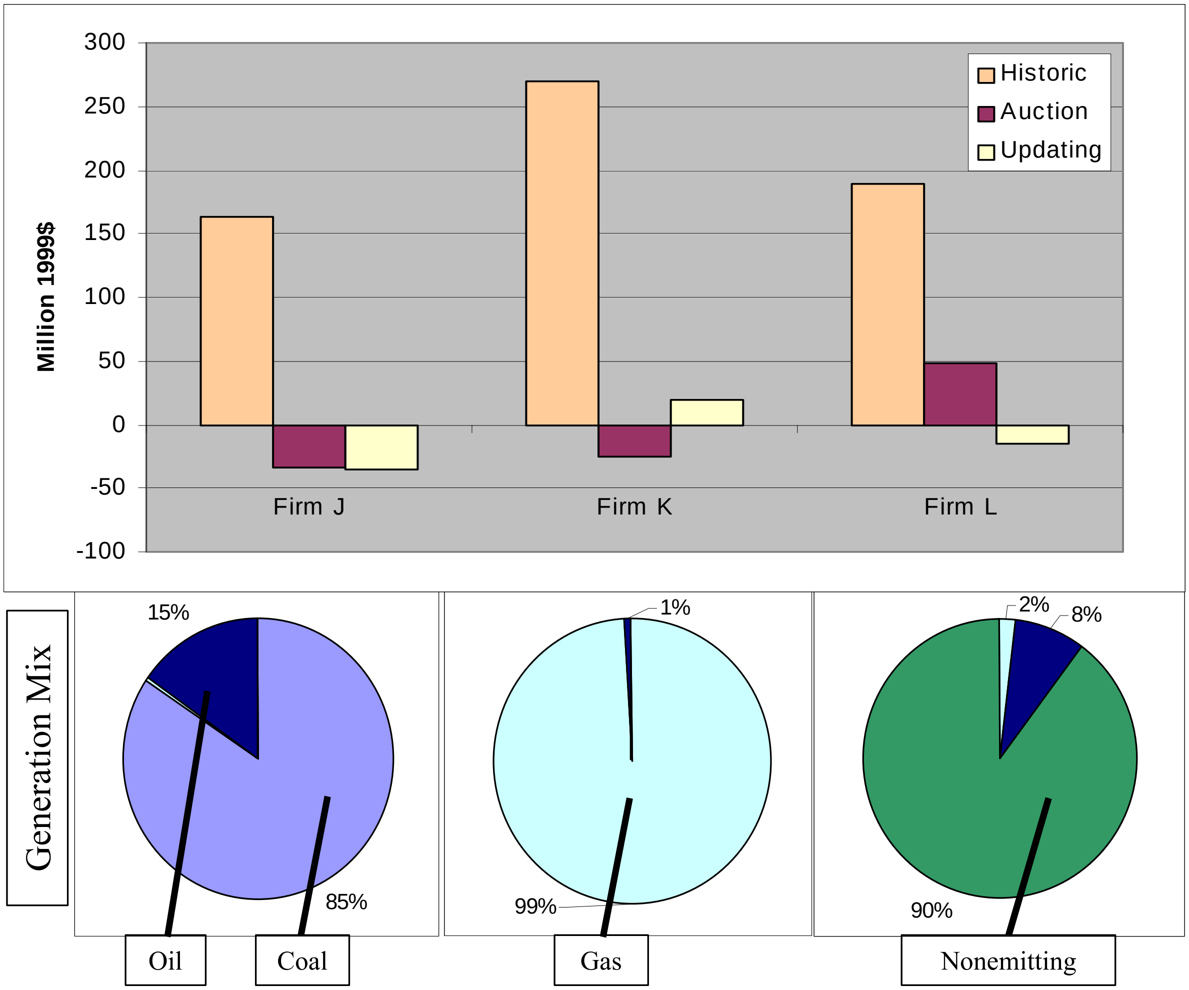
A comparison of Figures 1 and 3 reveals that three firms that lose value under an auction in the RGGI region gain value when assets in the larger region are accounted for. Similarly, three firms that lose value under updating in the RGGI-only regional analysis gain value in the analysis of the larger region. Overall, many firms fare substantially better when assets in the larger region are taken into account.

4.5. Comparison of Generation Mixes

Figure 4 illustrates in greater detail the change in asset value and generation mix in the RGGI region for a sample of three firms. While the firms' generation mixes are quite different, they all do well under a historic allocation approach. Every type of generation can benefit under historic allocation: Emitters are given allowances for free, and nonemitters benefit from the higher price in the RGGI region that results from the policy.

However, the story is mixed under auction and updating approaches. Firm J is composed almost entirely of coal- and oil-fired generation and loses value under both approaches. With an auction, the increased electricity price is not enough to compensate for the cost of having to purchase allowances. The firm has no nonemitting generation to reap the higher price without having to pay for permits. Under updating, coal- and oil-fired generation receive a smaller share of the allowances than under a historic approach because new generation—primarily gas—receives a portion. The smaller allocation combined with higher allowance prices and smaller increases in electricity price cause Firm J to lose value under this approach.

Figure 4. Shareholder Value for Three Firms: Effects on Assets in the RGGI Region



Firm K is composed almost entirely of natural gas–fired generators, and it gains value under updating but loses value under an auction. Although natural gas–fired generators need to buy fewer allowances per megawatt-hour of generation than coal- or oil-fired generators, the cost of auctioned allowances combined with reduced demand for electricity from RGGI generators is enough to cause Firm K to lose value under that approach. Additionally, natural gas provides less generation in the auction than in the baseline, so natural gas–fired generators lose the opportunity to reap some of the higher revenue under an auction. Although the electricity price increase and permit allocation are not as large under updating as under the historic approach, Firm K still increases in value compared to the baseline. Under the updating approach, natural gas is the main substitute for coal, so Firm K's assets generated more than in the baseline scenario and took in more revenue. Additionally, Firm K owns some new gas-fired generation facilities that receive a permit allocation.

Firm L is composed of 90 percent nonemitting generation along with a small amount of generation fired by natural gas and oil. Under the auction, the increase in electricity price is enough of a boon to the nonemitting generation to compensate for the cost of permits that must be purchased for gas- and oil-fired generation, and Firm L ends up gaining value. Under updating, the electricity price is not high enough to compensate for allowance costs and Firm L loses value, but the loss under updating is only about one-third of the gain under an auction.

5. Conclusion

How emission allowances are allocated to generators in the RGGI region will have important implications for the value of generation assets. The magnitude and direction of these effects will vary across generating facilities depending on the type of fuel used at a facility and its location. The effects of allowance allocation on individual firms also will depend on the mix of fuels used and the location of generating facilities.

All of the generators located within the RGGI region realize increases in asset value under a historic approach relative to the no policy baseline and small decreases under an auction. Aggregate asset values decline more under updating. The picture is slightly different when generators are grouped by fuel type. Coal-fired generators realize a slight increase in value under the historic approach and suffer a large decrease in value under an auction and an even larger decrease under updating. As a group, nuclear generators not under long-term contract fare best under the historic approach but also gain substantial value under an auction. Gas-fired generators also do best under a historic approach but perform almost as well under updating.

For a more complete picture of the effects of the RGGI policy on generation asset values, one must look beyond the RGGI region. Under both historic and auction approaches, the policy as modeled leads to substantial increases in power exports and a slight increase in the price paid for exports to the RGGI region as well as in the electricity price paid by native consumers within those exporting regions. The increased revenue associated with these changes helps to augment gains made within the RGGI region or, in some cases, to partially or fully offset losses incurred within the RGGI region.

The results of our firm-level analysis help to explain why electricity producers typically overwhelmingly support a historic approach to allowance allocation. According to our analysis of the 23 largest generating firms in the RGGI region, the value of the assets located in the RGGI region for every firm in the group except one is higher under historic allocation than with no policy, and almost every firm realizes its highest value under historic allocation. Expanding to incorporate non-RGGI assets substantially increases the size of the gains in value that firms realize as a result of the RGGI policy.

The auction approach produces a mix of winning and losing firms. Asset values within the RGGI region increase under an auction for 9 of the 23 largest firms; when assets outside the RGGI region are considered as well, 3 additional firms see gains under an auction. Mirroring the industry-wide results, most firms tend to perform better under an auction than under an updating approach. The exceptions are typically smaller firms, many of which perform equally well under auction and updating approaches. The few larger firms that perform better under updating than under an auction tend to own substantial gas-fired or nonemitting generation.

The primary justification for the free allocation of allowances is compensation for the adverse impacts of the cap-and-trade program on generators that do business within the RGGI region. This analysis suggests that most of the largest firms in RGGI will realize large increases in value under a historic approach to allocation and that all firms are more than adequately compensated for costs they incur under the RGGI policy when a historic approach is used. These results further suggest that a free allocation of less than 100 percent of the allowances would be adequate to compensate firms for any losses under the RGGI program.

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