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Compensation Rules for Climate Policy in the Electricity Sector

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Abstract

Policies to cap emissions of CO_2 in the U.S. economy could pose significant costs on the electricity sector, which contributes roughly 40% of total U.S.CO_2 emissions. Whether producers or consumers bear the cost of this regulation depends on whether generators are subject to cost-of-service regulation or sell power at market-determined prices. Moreover, the claim for compensation by producers depends on the length of the yardstick used to measure harm. Under one recent and relatively modest proposal, when measured at the facility level, the industry could suffer a loss of $50 billion (1999$). However, many facilities gain value. At the firm level where investors own a portfolio of facilities the loss would sum to $14 billion, while many firms would enjoy a substantial gain in value. Under this proposal the net present value of emission allowances sum to $141 billion. Hence, free distribution to electricity generators of emission allowances needed to cover electricity sector emissions has the potential to substantially over-compensate generators. The initial distribution of a portion of the valuable emission allowances represents a significant potential source of compensation, but it is easy for the compensation to fail to reach those who bear the burden of costs. Free allocation also has substantial efficiency costs, raising the social cost of a policy that already promises to be more expensive than prior air pollution regulations.

In this paper we look for approaches to target the initial distribution of emission allowances in order to maximize the share of allowances available for auction while achieving specified compensation goals. Using a detailed simulation model, we find that if regions or states are assigned emission budgets and apportioned emission allowances, they can achieve full compensation using facility-level information with just 39% of the emission allowances, which leaves a net gain in the industry of $19.5 billion. If allocation remains a federal matter then information about firm-level emission rates can be used to fully compensate firms using 65% of emission allowances. This approach leaves a net gain in the industry of $36.7 billion. Even under the best of these circumstances, the cost of delivering $15 billion in deserved compensation is $55 billion in allowance value. In the federal context we show that the incremental cost of compensating for the last $2.6 billion in harm spread across 81 firms would cost about $62 billion in allowance value.

Key Words: emissions trading, allowance allocations, electricity, air pollution, auction, grandfathering, cost-effectiveness, greenhouse gases, climate change, global warming, carbon dioxide, asset value, compensation

JEL Classification Numbers: Q2; Q25; Q4; L94

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1. Introduction

Emission allowances represent an enormous economic value – tens of billions of dollars annually under a federal carbon policy – that arise due to the value placed on emissions within a cap and trade system. The burden of the cost of emission reductions as well as the cost of paying for the use of emission allowances forms the basis of stakeholder claims for compensation. The initial distribution of just a portion of the valuable emission allowances represents a significant potential source of compensation, but it is easy for the compensation to fail to reach those who bear the burden of costs. The enormous value of the allowances makes this high stakes issue into perhaps the greatest political challenge in designing climate policy.

Strong incentives exist for individual parties to argue for an ever-increasing share of emission allowances through free allocation. Therefore, policy makers need to identify clear policy goals to be achieved through free initial distribution, and to limit and target that distribution. It is essential for successful public policy that principle rather than a contest of self-interest guide decisions about the free allocation of emission allowances.

Efficiency is one such bedrock principle. If society can achieve its goals in an efficient manner then this leaves more resources for families and businesses, or allows us to achieve greater environmental protection at the same cost. Many observers have turned to cap-and-trade or other incentive based approaches as a strategy to reduce the cost of emission reductions; however, the efficiency benefit of these approaches is not guaranteed. The overwhelming evidence from public finance and environmental economic research is that free distribution has a substantial hidden cost, and that a revenue-raising auction is the most efficient design for the initial distribution of allowances. [1] Never before has such an expansive environmental policy appeared on the horizon, and free distribution would multiply the cost of the policy.

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[1] An auction approach has dramatic efficiency advantages for two reasons. Many economists and other analysts suggest that auctioning provides a source of revenue that may have economy-wide efficiency benefits if it is used to reduce taxes, with potentially dramatic efficiency advantages compared to free distribution (Bovenberg and de Mooij 1994; Parry 1995; Bovenberg and Goulder 1996; Goulder et al. 1999; Parry et al. 1999; Smith et al. 2002). Moreover, an auction has a dramatic efficiency advantage in regions of the country where electricity prices differ substantially from marginal costs due to cost-of-service regulation because the auction approach tends to reduce the difference between price and marginal cost in this case (Parry 2005; Burtraw et al. 2001, 2002; Beamon et al. 2001).

Free allocation of emissions allowances to generators diverts revenues that otherwise could be dedicated to general tax relief, which offers tremendous efficiency gains and forms broad-based compensation for the diffuse effects of the policy on households. It also diverts revenues from other purposes, such as research initiatives or efficiency programs linked to climate policy. Policymakers need to be cognizant of likely impacts on all affected parties and they may want to limit and narrowly target free distribution of emissions allowances in order to be better able to address the broader set of efficiency and compensation goals. Indeed, absent a public policy rationale, there is an economic case against free distribution of any emission allowances.

However, there are at least three reasons for free initial distribution of emission allowances. The rationale that we examine is to provide compensation to parties that will bear a disproportionate cost under the trading program. A frequently cited principle of public policy is that government should “do no direct harm” (Schultze 1977), that is, public policy needs to respond to the direct harm that may be concentrated on severely affected parties through compensation for some degree of the disproportionate cost burden they bear. Compensation can take a variety of forms. One form is the time delay between the announcement of a policy and its implementation, which provides for the realization of economic value from previous investments while giving investors the opportunity to realign their investment decisions going forward. Years that have transpired between the announcement of national climate policy goals and the implementation of a mandatory policy have provided such opportunity. Another fundamental form of compensation within a cap and trade program is free initial distribution of emission allowances because it conveys substantial economic value to recipients. Nonetheless, this approach has the advantage, at least from the perspective of those affected, that it keeps value in the regulated industry and away from the vagaries of government appropriation. Furthermore, the magnitude of the compensation moves in direct proportion to the harm, which is evident when emission allowances gain or lose value.

Although we focus exclusively on the issue of compensation, there are at least two other rationales for free distribution. One is the maintenance of competitiveness of the regulated sector in an open economy if competitors do not face comparable environmental constraints. There is little accomplished by reducing emissions in the United States if economic activity and associated emissions move off shore. Allocation to firms based on their share of production (output) going forward into the future provides an incentive to expand output on shore (Fischer and Fox 2004) or within region or sector of the economy (Burtraw et al. 2001). Yet another rationale for the initial distribution of emission allowances is to use their value to explicitly promote new technology (Energy and Environmental Analysis, Inc. 2003). We will not pursue either of these issues here.

We limit this paper to an investigation of the need for compensation, and to do so one must recognize various trade-offs. Not only does free allocation move society away from the most efficient design; free allocation to one party depletes the allowance value that is available for other severely affected interest groups or other complimentary policy goals. These ideas provide two design criteria to guide the initial distribution of emission allowances:

- First, maximize the portion of emission allowances that can be distributed in an efficient manner (e.g. through auction).
- Second, direct the free distribution of emission allowances to mitigate the direct harm to severely affected parties (while minimizing free allocation overall).

To design this compensation strategy requires two pieces of information about electricity suppliers. Policy makers need to know how parties are affected under the policy, and how to deliver compensation effectively in order to minimize the amount of over-compensation and maintain a preeminent consideration of efficiency in the design of the policy.

The claim to compensation depends on how the effect on producers and consumers is measured. Previous studies have analyzed the effect at the industry level, which tends to provide a relatively low estimate of the claim for compensation of firms, or at the facility level, which tends to provide a higher estimate. Bovenberg and Goulder (2001) estimate that the effect of a 23 percent decline in emissions from 2002-2080 would cause industry-wide losses of just $28 billion by investors in the electricity sector. They find losses about twenty times as large in the fossil-fuel supplying industries (CBO 2003). Smith et al. (2002) estimate the effects of a 14 percent decrease in emissions over the course of the decade to be achieved by 2010, and a 32 percent decrease by 2030. The reduction in equity value was estimated to be equivalent to 6 percent of the total allowance value. Taking the nature of regulation in the electricity sector into account as well as the organization of firms, we provide an estimate of the change in market value at the firm level, and we argue this is the primary metric for measuring the impact on producers that is relevant for the policy debate. We find that the majority of harm is born by consumers rather than producers, although this harm is diffuse in the economy, and hence consumers may have secondary claim behind producers, who bear a concentrated burden from the policy.

The award of free allowances is a blunt instrument for compensation, especially at the federal level. It tends to reward consumers in regions of the country with cost of service electricity pricing, and tends to reward producers in regions with market based pricing. Furthermore, unless the policy is discriminating, it tends to reward winners as well as losers, thereby eroding efficiency as well as the ability to compensate other affected parties. In this paper we develop decision rules that can guide the delivery of compensation while minimizing over-compensation. Consumer interests are best protected by ensuring the program is efficient and by minimizing direct compensation to industry. Allocation of as much of the allowance value as possible to broad-based revenue recycling and tax relief would be a direct way of achieving efficiency and compensation for consumers simultaneously. However, compensation to severely affected consumers may take alternative forms, such as low-income assistance programs.

Using a detailed simulation model, we analyze a relatively modest recent proposal from the National Commission on Energy Policy (NCEP), and alternatives based on that proposal. We find that the best approach to compensation and the associated share of allowances that the regulator can set aside to auction while still compensating firms depends on whether compensation is done at the state/regional or federal level of government. If regions or states are assigned emission budgets and apportioned emission allowances, they can achieve full compensation using facility-level information and do so more efficiently than could be done using similar rules at the federal level. At the regional level, facility-specific information can enable full compensation to be achieved with 39% of the emission allowances, which leaves a net gain in the industry of $19.5 billion. If allocation remains a federal responsibility, then information about firm-level emission rates would provide a much more efficient basis for achieving compensation goals. At the federal level, full compensation using average emission rate information could be achieved with 65% of emission allowances. This approach leaves a net gain in the industry of $36.7 billion

On the other hand, if regulators can implement a strategy to get firms to reveal their costs then they could compensate losers directly without providing compensation to winners. In this case, it would be sufficient to give away just 22% of the emission allowances for free. This approach still leaves a net gain in the industry of $7.51 billion. Stranded cost recovery investigations by public utility commissions provide some experience with potential revelation strategies.

These estimates are a point of departure, calculated as if the policy were to take effect immediately without warning, as a surprise. If we consider a more realistic delay between adoption and implementation then firms have an opportunity to depreciate existing capital and adjust investment strategies, lowering the impact of the policy. Compensation targets may be set at less than 100% compensation for other reasons also. The most compelling reason to limit compensation is its opportunity cost. Even under the best of these circumstances, the cost of delivering $15 billion in deserved compensation is $55 billion in allowance value. In the federal context we show that the incremental cost of compensating for the last $2.6 billion in harm spread across 81 firms would cost about $62 billion in allowance value. These estimates do not account for the tax interaction effect and the opportunity for revenue recycling.

2. Method of Analysis

We focus the analysis on the electricity sector, which represents roughly 40% of carbon dioxide emissions in the economy, but which is expected to yield roughly 70% of emission reductions under future carbon policy (EIA 2005b). The analysis is conducted using a detailed simulation model of the electricity sector maintained by Resources for the Future (Paul and Burtraw 2002). The model accounts for temporal detail with three seasons and four time blocks and solves for investment and operational decisions over a twenty-five-year horizon.

2.1. Baseline Assumptions

The baseline model simulation in this exercise uses fuel price and electricity demand that are calibrated to the *Annual Energy Outlook 2005* (EIA 2005a) levels. Fuel prices and electricity price vary in response to changes in the quantity supplied. The level of demand for both electricity and fuels responds to price changes including those associated with a carbon policy. Demand is represented by a constant elasticity function $Q_i\left(P_i\right) = A_i \cdot P_i^{\varepsilon_i}$ where *P* is electricity price in a given time block, Q_j is quantity demanded by an individual customer class in each time block, season and region, *A* is a constant used in calibration and ε_i is the own price elasticity of demand. The quantity demanded is summed across three customer classes in each market. In principle ε_i varies by region customer class and time block; in practice data is scarce and elasticity values are common across many of these distinctions. Aggregate weighted elasticity of demand is approximately -0.25.

The baseline includes the national restrictions on SO_2, NO_x and mercury emissions from electricity generators under Title IV as well as additional emissions restrictions found in the Clean Air Interstate Rule and Clean Air Mercury Rule. It does not include the Regional Greenhouse Gas Initiative to be implemented in northeast states beginning in 2009 because we anticipate that the results would be most useful if they reflect the total cost of climate policy, rather than just the incremental cost of the national policy given the regional policy.

A critical assumption is the status of regulation in the electricity sector. Roughly speaking, half of the consumers in the nation buy electricity at **competitive** market-based prices, and half buy electricity at prices determined by the cost of service of **regulated** firms. Our model represents the nation as thirteen sub-regions. In our standard regulatory case, we assume six of the sub-regions have market-based prices and seven have cost of service regulation.[2] We model cost of service regulation in a textbook manner. In each sub-region the total annual cost of production is aggregated and divided by the electricity quantity that is sold to achieve an average generation price that is added to transmission and distribution costs. The electricity price varies for different customer classes reflecting empirical practice that shares transmission and distribution costs in different ways for different classes of electricity customers.

The key aspect of cost of service regulation is that all costs are included at original cost and the firm is reimbursed for those costs. In the short term there are numerous variations from this rule in practice, as regulators disallow some types of costs and encourage others. The time lag in administrative proceedings that precede many types of adjustments to the ratebase provides regulated firms with an opportunity to gain or lose earnings. If firms can cut costs while price remains unchanged, they can profit. If costs rise they lose. Often regulators will consider ex post adjustments to account for changes in costs, and usually changes in fuel cost are automatically passed through as changes in price, but in many cases the unexpected changes in costs are not recovered fully by the firm. In addition, many regulators appear willing to leave prices stable as costs fall, but they are less willing to increase prices when costs rise because any increase in price triggers a political reaction (Joskow 1974; Joskow and Schmalensee 1986). Consumer advocates argue that such increases should have been anticipated and avoided. When price does increase, it can lead to reductions in demand, thereby lowering sales revenue to the firm. And finally, one should note that managers of the firm are under increasing pressure from capital markets to maintain short run profitability. All these factors together suggest that regulated firms are likely to be opposed to new costs.

[2] We characterize six sub-regions of the North American Electric Reliability Council (NERC) as competitive including New York, New England, Mid-Atlantic (MAAC), Illinois area (MAIN), the Ohio Valley (ECAR), and Texas (ERCOT)—and that there is time-of-day pricing of electricity for industrial customers in these regions.

In the long run, however, firms must recover their cost of providing service. Otherwise in the long run there would be excess profits implying regulators are not applying a test of prudence on cost recovery, or firms would lose money and go out of business. We take a long run perspective and assume that because producers in regulated regions are reimbursed for all costs they are fully compensated for the cost of climate policy through changes in electricity price.

In competitive regions, generation cost is determined by the variable cost of the marginal facility at every point in time.[3] In the absence of time of use pricing for residential and commercial customers, the marginal generation cost is averaged over the hours of the day to achieve an average marginal generation cost. We assume industrial customers in competitive regions see time of use pricing, so their price is the instantaneous marginal cost. Since the price is set by marginal cost, rather than average cost, characteristics of the marginal generation facility determine the change in electricity price due to the program and ultimately the ability of the industry to pass on costs to consumers through higher prices. We see that the assumption about the nature of regulation in the electricity industry has an important bearing on the expected cost of the policy and who bears the cost.

2.2. Alternative Methods for an Initial Distribution of Emission Allowances

The policy we model based on the NCEP proposal is a cap and trade system for the entire economy with point of compliance at upstream fuel supply. The policy would require fuel suppliers to surrender allowances equal to the carbon content of the fuel and byproducts that they sell or consume in their refining and manufacturing processes. In the downstream electricity sector, the cost of such a cap and trade system would be perceived as a change in the relative cost of fuel. Fuel with a relatively high carbon content would be expected to have a higher price because of the opportunity cost of emission allowances that fuel suppliers would have to surrender in order to bring that fuel to market.

We evaluate alternative points of allocation of emission allowances that generally are distinct from the point of compliance. One alternative is **upstream allocation**, with all emission allowances distributed initially to fuel suppliers and with no allowances distributed to the electricity sector. Within the electricity sector, this approach would be perceived as an **auction** regardless of how the allowances are actually distributed to fuel suppliers because electricity generators purchase their emission allowances bundled along with their fuel through an increase in the price of fuel. Subsequently, as an alternative to upstream allocation (auction) we consider free distribution of some allowances to the electricity sector on the basis of **historic** measures of electricity generation; this approach is often called grandfathering because it distributes allowances without charge to incumbents in the industry. Another approach, which we do not explore here, is to regularly **update** the calculation underlying the allowance distribution based on current- or recent-year data. Like distribution based on historic data, an updating approach distributes allowances free of charge and also could distribute them according to various measures, such as the share of electricity generation or heat input (a measure related to fuel use and CO_2 emissions) at a facility (Burtraw et al. 2001, Fischer and Fox 2004). An updating approach leads to lower electricity prices than an auction or historic

[3] Payment for reserve is determined by the going forward cost of marginal capacity.

approach and therefore it is expected to have greater social costs because it does not provide the same incentive through higher prices for consumers to improve the efficiency of energy use.

2.3 Policy Scenario

The emission reduction targets that we model are taken from the EIA modeling of the National Commission on Energy Policy CO_2 Cap-and-Trade proposal with an upstream allocation policy and with the safety valve (EIA 2005b).[4] From that modeling we take the CO_2 allowance price determined at the national level as given, and we assume it is not affected by small changes in the electricity sector that result under the variations of policies we model. The EIA forecast includes a safety valve price that is binding after 2016. Investment and operational decisions in our model respond to this fixed price. In reality (as opposed to in the model), the electricity sector decisions would play a role in the determination of the national price, but we maintain the fixed price in order to achieve comparability with EIA results. Since price is the same and the models are different, our model will result in a different level of emissions than that obtained in the EIA exercise. The EIA emission and price targets and our modeled policy are compared in Table A.

<Insert Table A here>

The results of this exercise for the year 2020 are reported in Table B. We find baseline generation for the nation of about 4,777 billion kWh decreases by about 1.5%. The upstream allocation policy leads to a reduction of about 94 million short tons of CO_2 associated with electricity generation. (For comparison, we report that the EIA modeling finds this policy would yield a reduction of about 112 million short tons.) Slightly more than half of the reductions occur in competitive regions and the rest occur in regulated regions.

<Table B about here>

3. Producer Claims for Compensation Depend on the Length of the Yardstick

We use simulation modeling to account for the equilibration of electricity markets on a sub-regional basis, by season and time of day, and for changes in new investment and retirement. The level of detail in the analysis has a significant effect on calculation of changes in the market value of existing generation assets. The basic element of the cost to investors is the change in market value of an individual electricity generating facility, which we calculate using a discounted cash flow model of activity through 2030,

[4] A safety valve is a price range that bounds the variability in the allowance price. The NCEP proposal is a one-sided safety valve that places a ceiling the price.

discounted back to 2006. Table B reports the loss in market value of facilities sums to almost $50 billion. [5]

However, investors do not own stock in facilities. Rather, investors own stock in firms that own a portfolio of facilities. At the firm level the loss in value at one facility may be offset by the gain in value at another facility. To calculate the change in value at the firm level we aggregate individual facilities to portfolios owned by firms as of January 2004. The value of new facilities that the model predicts will be built after 2005 is not included in these calculations. In addition, we assume that in regulated regions the vast majority of federally mandated environmental costs would be included in the rate base, as has been historic practice, and that the regulated rate of return on invested capital is maintained, so the cost at the firm level in these regions is zero. Therefore we assume that only firms in competitive regions are directly affected in the long run and they suffer a loss in market value that totals to $14.95 billion. Many firms that gain value are excluded from this calculation.

The third potential level of aggregation is the industry level, at which the increase in market value at one firm may offset the loss in market value at another. If one believes that most investment occurs not in the form of stock or bond holdings in individual firms, but in a portfolio of firms captured in various industry indices held by mutual funds or large pension funds, then the industry level measure might be the preferred measure of damage. For example, a growing portion of the stocks on Wall Street are held by mutual funds or institutional investors, suggesting that for many investors the effect on the industry is more relevant than the effect on individual firms.[6] At the industry level, the total drop in market value is $9 billion.

Figure 1 illustrates the way in which the level of aggregation — at the facility, firm or industry level — determines the claim for compensation in the electricity industry, causing the estimate of direct harm to producers to vary by a factor of 5. Also noted is the $141 billion net present value of the stream of emission allowances for the policy. Were it feasible to compensate for the $9 billion loss at the industry level – effectively leaving shareholders financially unaffected by the policy – it would be sufficient to allocate for free just 6.4 percent of the allowances. If one considers just the pool of allowances in competitive regions, the loss in market value represents 13.2 percent of the allowance value. In contrast, full compensation for the loss of $15 billion at the firm level could be achieved for as little as 22 percent of the total allowance value in competitive regions, while creating an increase of $6 billion in the net value of the industry.

In principle, this information suggests that free allocation of emission allowances not only has the potential to compensate the shareholders for changes in the market value, but potentially to over-compensate substantially for the cost of the policy. Burtraw et al. (2002) and Bovenberg and Goulder (2001) find that, in the case of nationwide CO_2 regulation, the free allocation of emissions allowances can dramatically overcompensate the electricity industry in the aggregate, although different parts of the industry are

[5] All values are reported in 1999$.

[6] Individual and institutional mutual fund accounts manage nearly $9 trillion dollars of value in 2005 (Investment Company Institute 2006, *2006 Fact Book*).

affected very differently. Analysis of the CO_2 emissions trading system in Europe that began in 2005 has reached a similar conclusion (Sijm et al. 2005; UK House of Commons 2005). In the Regional Greenhouse Gas Initiative (RGGI), earlier work (Burtraw et al. 2005, 2006) suggests that giving away 100 percent of the allowances for free to emitting generators based on historic output (or other measures) will more than compensate generators for the costs of the program. Using a simple model with fixed capacity and fixed demand in the RGGI program, the Center for Energy, Economic and Environmental Policy (2005) finds that all three approaches to allocation—historic, updating and auction—would lead to increased profitability for the electricity sector as a whole in RGGI relative to no policy, with the historic approach resulting in the greatest increase in profits.

<Insert **Figure 1** about here>

4. Consumer Claims for Compensation are Diffuse

The case for consumer compensation depends on the change in electricity prices, which increase by $4.05/MWh (6%) at the national level in 2020. This leads to an overall increase in expenditures by consumers of $18.6 billion in that year.[7] The impact of the policy on consumers can also be measured by the partial equilibrium change in consumer surplus, which is measured as the area under the demand curve for each customer class in each linked electricity market. In 2020, the loss in consumer surplus is $18.2 billion, which is less than the change in expenditures because of the curvature of the demand curve. The net present value of change in consumer surplus over the entire forecast horizon is $135.6 billion.

The impact of the policy on consumers is not uniform across the country. Consumers in regions with a greater dependence on fossil generation tend to experience greater losses than those in regions with more mixed generation portfolios. We adjust for size of the regions by dividing the net present value of change in consumer surplus by the level of electricity demand in the region to yield a measure of surplus change per kWh of demand. Ranking the 13 regions by this measure shows where consumers are most affected per unit of electricity consumed. We also rank regions according to the fossil fuel intensity of their generation mix in 2020. A Spearman rank correlation test indicates that these two rankings have a correlation coefficient of .797, which is statistically significant at the 99% level. Thus, the effect of the climate policy on consumers across different regions is highly dependent on the fossil intensity of a region's generation.[8]

[7] This cost is estimated as the change in national average retail price multiplied by the quantity of electricity consumed. The quantity of electricity consumption varies between the baseline and policy scenario due to the change in retail price. We use the average of baseline and policy scenario quantities.

[8] It is unclear whether this correlation would persist at higher allowance price levels. Preliminary results with a doubling of the allowance price cap suggest that the effect on consumer prices will be much larger in competitive regions than in regulated regions, despite the fact that many of these regions tend to be lower ranked in terms of fossil intensity than are the regulated regions.

Typically the price impact of the policy tends to be bigger in regulated regions than in competitive regions because consumers bear both the higher fuel cost due to the embedded cost of allowances and the cost associated with fuel switching and other steps taken by generators to reduce CO_2 emissions. This is true in particular for those regions with a majority of coal-fired generation. Several regulated regions have more than the national average share of coal-fired generation. The biggest price increases happen in regions with a large amount of coal and a small fraction of non-emitting generation. The highest price increase happens in the SPP sub-region (largely Oklahoma and Kansas and parts of Louisiana and Texas), a regulated region with only 6.5% non-emitting generation in 2020 in the baseline. A separate Spearman rank correlation test between NPV of consumer surplus change per kWh demand and fossil intensity of generation within just the set of seven regulated regions reveals a rank correlation coefficient of .786, which is significant at the 95% level.

In competitive regions the compliance cost is not necessarily fully reflected in electricity price. The determination of electricity price depends on the fuel that is at the margin and most often that fuel is natural gas. When this is the case, the change in electricity price will be less than were coal at the margin and the change in electricity price may not be sufficient to compensate the firm for its increase in cost. On the other hand, if a firm had no coal generation but substantial non-emitting generation, the change in electricity price when natural gas is at the margin could overstate the change in the firm's cost of generation. Thus, the change in electricity price may understate or overstate the average cost per MWh of electricity generation, depending on the relationship between the marginal and the average carbon intensity of electricity generation. The more indirect link between effects of the policy on cost and electricity price in competitive regions can be illustrated by another Spearman rank correlation test on just the subset of restructured regions. In this case the correlation coefficient between the rank of fossil intensity of generation and change in consumer surplus per kWh is .743, which is not statistically significant given the small sample size.

The competitive region with the largest price impact is ECAR (central Ohio Valley), which has 84% coal generation and over 90% fossil generation, and where coal is more likely to be at the margin than in any other region. The price impact in ECAR is second highest of all regions for the nation.

5. How Well Does Free Allocation Compensate Producers and Consumers?

As an alternative to upstream allocation or distribution through an auction, we consider free initial distribution to producers of all emission allowances used by the electricity industry. We model the initial distribution of 100% of allowances to electricity generators based on a facility's share of total heat input at emitting facilities in 1999.[9] This is similar to the approach used in Title IV of the 1990 Clean Air Act Amendments that gives SO_2 emission allowances away to facilities based on a measure of performance in the 1985-1987 base period, and this allocation formula is carried forward in the Clean Air Interstate Rule for SO_2.

[9] This is comparable to their share of emissions.

5.1. Generators in Competitive Regions and Consumers in Regulated Regions Benefit from Free Allocation

With free allocation there is a marked difference between competitive and regulated regions in the effect of the policy on electricity prices and therefore on consumers. Generators in regulated regions should be indifferent in the long run between free allocation to generators and an auction. In these regions free allocation will benefit electricity consumers by reducing the revenue requirement that determines the electricity price.

The differing effects on consumers between competitive and regulated regions are illustrated in figure 2. This figure displays the distribution of the change in average retail electricity price in 2020 aggregated at the level of the thirteen sub-regions in the model. Panel (A) in the figure corresponds to the upstream allocation policy, which is equivalent to an auction from the perspective of the electricity industry. Competitive regions and regulated regions are distinguished by different shading in the figure. The average change in price for the nation is $4.05/MWh. The price increase is about $0.53/MWh (14%) greater in regulated regions.

<Insert Figure 2 about here>

Panel (B) in the figure corresponds to free allocation to generators in the electricity industry. Comparing the panels shows that free allocation has only small effects on the distribution of cost for customers in competitive regions. This is because the electricity price is set by the cost of the marginal generator, and that cost does not change substantially with free allocation in competitive regions. In the aggregate, consumers in competitive regions are slightly worse off than under an auction by $630 million and would bear a total cost of $8.1 billion.[10] However, free allocation has a dramatic effect in regulated regions, where the change in electricity price is reduced by 90% on average to about $.40/MWh. In regulated regions free allocation offsets the cost of allowances that is embedded in the cost of fuel and removes that cost from the rate base, thereby lowering average cost and electricity price. Free allocation benefits consumers significantly in regulated regions, but it does not benefit consumers in competitive regions, unless consumers receive the allowances directly.

Table D summarizes the effects of free allocation on consumers and producers separately in regulated and competitive regions in the year 2020. As shown in the table, with free allocation to the electricity sector electricity consumers in regulated regions are compensated for 91% of the losses they incur under the upstream allocation (auction) approach. In contrast, in competitive regions, generators are the ones who stand to gain from free allocation. Table D reports for the year 2020 that generators in competitive regions realize $11.14 billion gain relative to an auction which is more than three times their loss under upstream allocation, resulting in substantial overcompensation of generators totaling $8.26 billion.

[10] In competitive regions the increase in price in 2020 is larger than under an auction because of the relatively greater level of demand in regulated regions and its effect on the wholesale power market.

<Table D about here>

Over the entire planning horizon the present discounted value of the gain in asset values for the industry under free allocation is more than $68 billion, while the few firms that lose incur a loss that totals just $110 million. The majority of firms in competitive regions gain significant value.

Figure 3 illustrates that upstream allocation and free allocation affect firms quite differently. The figure characterizes approximately 150 firms that account for 93 percent of the electricity generation identified in the model to exist in 2010. New facilities built after 2004 are automatically not assigned to these firms. The model indicates the largest 20 firms would account for 51 percent. The distribution of the change in market values under the upstream allocation policy is displayed in the left-hand side distribution in Figure 3. The horizontal axis represents the change in market value of a firm averaged over the kilowatts of generating capacity it owned in 2005. The heights of the bars represent the total amount of generation capacity that falls into each category of change in value. Under upstream allocation about 33 percent of the firms lose market value while 21 percent gain value. Only assets in competitive regions of the country are included in the figure. The remaining 46 percent of firms only have holdings in regulated regions and experience no change in market value due to cost of service regulation.

<Insert Figure 3 about here>

The distribution on the right of figure 3 represents changes in asset value under a policy with free allocation to generators. In this case we see that virtually every firm gains value under the climate policy. The average firm gains about $165 per kW of generation capacity.[11]

In sum, free allocation primarily benefits two groups. One group that benefits is consumers in regulated regions where electricity price is the average cost of service. To a first order approximation, producers in regulated regions are not expected to benefit from free allocation because cost of service regulation is expected to assure recovery of costs. The second group that benefits is producers in competitive regions. Consumers in competitive regions do not benefit directly from free allocation to producers because free allocation has no direct effect on the determination of electricity price.

Free allocation of 100% of emission allowances would provide compensation far in excess of damage to most firms. We presume the policy goal is to compensate severely affected parties while at the same time minimizing the amount of compensation overall.

[11] When weighted by the size of the firm the average firm gains about $187 per kW, indicating the largest firms have the most to gain from free allocation. By way of comparison, EIA estimates the cost of a new scrubbed coal-fired power plant today is about $1,102 per kW (1999 $). The electricity industry has about 950 million kW of installed generation capacity in 2006.

Consequently, the challenge is how to provide compensation to the electricity industry without transferring wealth to the industry or to individual firms in excess of their harm.

5.2. Efficiency Cost of Compensation

Compensating through free allocation to producers mutes the effect of the cap and trade policy on prices paid by consumers in regulated regions, but this approach to compensating consumers comes at an efficiency cost in the form of lower reductions in CO_2 emissions from the electricity sector. Given the cap on the price of emission allowances specified in the policy scenarios runs, the approach to distributing allowances will affect the level of emissions reduction and how those reductions are achieved. In 2020, CO_2 emissions associated with electricity generation fall by 94.1 million tons when allowances are distributed to upstream fuel suppliers, but by only 75.8 million tons when all of the allowances for emissions associated with electricity generation are distributed for free to electricity generators. With upstream allocation, electricity prices in both regulated and competitive regions reflect in some direct manner the opportunity cost of using allowances and thus there is a greater incentive to conserve electricity to reduce emissions. With free allocation, the opportunity cost of using allowances is not reflected in electricity prices in regulated regions thereby muting incentives for conservation. As a result emission reductions are substantially lower.

<Insert Figure 4 here>

The changing relative importance of reductions in generation as a means of achieving emissions reductions is reflected in the graph in Figure 4. The two panels of this graph show the relative sources of emission reductions in 2020 under the two allocation approaches and the relative total areas of the two pie charts reflect the relative size of the total emission reductions from electricity generators associated with each allocation approach.

In panel (A) we see that reductions in total generation are responsible for 83 % of the 94.1 million ton CO_2 emission reduction from electricity generators achieved with the upstream allocation approach. Reduction in electricity generation subsumes investments in end-use efficiency and conservation measures, which are accounted for in the model by the own-price elasticity of demand. The second most important source of reductions is fuel switching from coal to renewables, which accounts for 9% of emission reductions. Approximately 5% of the emission reductions come from improvements in efficiency by switching among coal-fired generators. Interestingly switching from coal to gas and from coal to nuclear account for only about 1% of total emissions reductions.

In panel (B) we see that under free allocation to electricity generators the role for efficiency or energy conservation leading to reductions in electricity generation is much reduced to only 47% of the 74.1 million ton total emissions reduction. Under this scenario, fuel switching from coal to gas and from coal to renewables both become much more important, accounting for 24% and 20%, respectively. Fuel switching from coal to nuclear is still relatively unimportant as is switching among gas-fired facilities. The relative importance of shifting toward relatively more efficient coal facilities remains similarly as it was under the upstream approach.

5.3. Limited Free Allocation to Generators

To explore the middle ground between an auction and free downstream allocation to generators to see whether a mixed policy could provide limited compensation we model free allocation of 20% of the allowances, the level at which the market value of firms in aggregate is approximately unaffected by the policy. This percent is the ratio of losses in value at the firm level (roughly $14 billion), which are all in competitive regions, to the total present discounted value of allowances in competitive regions $68.27 billion. This percentage reflects an assumption that uniform allocation rules would govern competitive and regulated regions, but this might not be the case. The remaining allowances in this scenario are allocated upstream or auctioned. This scenario is compared with upstream allocation/auction and 100% free allocation for the year 2020 in Table E.

<Insert Table E here>

Allocation of 20% of the allowances for free to generators reduces the cost of the policy to producers in competitive regions in 2020 by $1.93 billion, from $3.43 billion under an auction to $1.5 billion. It also increases the gain among firms that profit from the policy by $972 million, from $0.46 billion to $1.32 billion. On net losses and gains in competitive regions and for the nation approximately break even with a 20% share of allowances given away for free. However, the policy still creates separate classes of losing and winning firms.

Consumers in regulated regions also benefit from the mixed policy relative to upstream allocation. Their cost falls in 2020 from $11.1 billion to $9.04 billion. Consumers in competitive regions actually see a small increase in their cost because of the expansion in demand in regulated regions and its effect in the wholesale power market. On net for all producers and consumers the cost to the electricity sector falls from $21.54 billion to $17.3 billion. Also available, however, would be approximately $17 billion in auction revenue.

6. Producer Claims for Compensation Vary Inversely Over a Range of Moderate Policies

The size of electricity producer claims for compensation depends on the stringency of the climate policy. Under stricter policies, the differences in producer costs among the different metrics - industry-level, company-level or firm-level - become even more pronounced than they are in the $7 price cap case. The results for a case with a $15 price cap are presented in Table F.

<Table F here>

This table shows that when viewed at the industry level, producers actually profit from the climate policy with industry wide assets *increasing* by $9 billion under the policy. Thus, if the disparate producers in the electricity sector could find a way to share the winnings from the climate policy among themselves, electricity producers as a whole would be better off with a CO_2 policy that caps allowance prices at $15 than without a CO_2 policy. However, at both the firm and facility level, the size of losses to the losers actually increases under the higher allowance safety valve price of $15 (relative to the $7 level reported in Table B). At the firm level, losses to losing firms nationwide total almost $40 billion while at the facility level, losses to losing facilities total just over $90 billion. These findings suggest that the spread between winning firms and losing firms and between winning and losing facilities grows bigger as the price of CO_2 emission allowances increases. We also evaluated an intermediate CO_2 allowance price cap level of $11, which yields an intermediate result with a small increase in asset values at the industry level of $1.5 billion and total losses to losers at the firm and facilities levels in between the other two cases.

On the consumer side, Table F shows that consumer losses between regulated and competitive regions are evenly split (about $23- 24 billion each) for a total of about $47 billion across the nation. This compares to a less even split in the $7 safety valve case, with 60% of the $18.6 billion in losses coming in regulated regions. Note that for an allowance price increase of just over 100% from $7 to $15, consumer costs in 2020 increase by about 150%. The higher allowance price hits consumers in competitive regions particularly hard, which is what one would expect given that all the winning generators are located in competitive regions.

7. Designs for Delivering Compensation to Firms

An auction of emission allowances imposes costs on some producers in competitive regions and on consumers in competitive and regulated regions. The revenue generated by an auction in 2020 would be $21.18 billion, which potentially could be used to offset most of the $21.54 billion in costs.

To compensate producers, the obvious level of compensation is the level of the firm because one cannot compensate individual facilities. Although there is a compelling case that workers and local communities may be affected by the policy, which that makes the case for minimizing compensation to industry in order to direct greater value to other constituencies. Conversely, even though the amount of compensation could be minimized if the industry could be the recipient, free allocation at the industry level would have to be assigned to firms.

We have seen that free allocation using the blunt instrument of a historic measure of emissions distributes the compensation to many firms who do not need compensation, while other firms may receive insufficient allocation to maintain the firm's market value. Therefore we seek to find simple decision rules that could govern the provision of compensation by guiding the distribution of allowances. We calculate compensation on the basis of a policy that has upstream allocation or an auction. Only firms in competitive regions are the targets of compensation. We calculate values as though compensation through allocation of allowances is also being delivered to consumers in regulated regions, but we do not consider the inclusion of these allowances in the rate base, which would lead to a different equilibrium of emissions for the nation as illustrated in Table C. Instead, we implicitly assume a different method of compensating consumers that does not influence electricity consumption directly.

7.1. Complete Information: Targeting Compensation to Firms

If a mechanism existed to allocate only to those firms that suffer a negative effect on market value, then the net present value compensation target is $14.95 billion, equivalent to 10 percent of the net present value of emission allowances. If one were to restrict free allocation to the pool of allowances to be used in competitive regions, which have a value of $68.3 billion, then 21.9 percent of the allowances offer value sufficient to offset the losses. These results are presented and compared with other approaches in Table G.

<Insert Table G about here>

If a regulator can identify the performance of individual firms under the trading program, one can imagine the regulator might seek to compensate firms through an individualized allocation of emissions allowances in order to achieve a precise compensation goal. One way the regulator may obtain such detailed information is by solving a simulation model. Another way the regulator may obtain information is by establishing a rebuttable presumption against compensation and inviting firms to appeal through the demonstration of harm, again presumably through the use of simulation modeling. These approaches would resemble the stranded cost recovery proceedings that accompanied the restructuring of the electricity sector in many states in the late 1990s, when regulators relied on simulation models to estimate the potential change in the value of generating assets due to restructuring.[12]

In the restructuring process, the modeling exercise led to contentious disputes between utilities and regulatory staffs (and consumer representatives) concerning the validity of simulation models, including key data input assumptions and calculation procedures. In the absence of case settlements, state commissions were required to adjudicate these very technical modeling issues. In the present case, similar disagreements can be expected. If energy efficiency or taxpayer advocates anticipate

[12] In the proceedings, regulators and utilities used three methods to estimate the potential change in value of generating assets due to restructuring (Kahal 2006). One was the measure of the change in the discounted value of revenues due to anticipated changes in prices as a result of restructuring. A second and conceptually similar method calculated the year-by-year revenues and costs of the generating assets in a deregulated market over the assumed remaining lives of the assets. The net present value (discounted cash flow) of this stream of profits was assumed to be the market valuation. The difference between the market valuation and the net book value of the assets (i.e., the value under regulation) measured the gain or loss from deregulation.

In the later stages of restructuring, the comparable transaction approach became widely used. This much simpler method involved compiling a database on generation plant sales (usually associated with utility divestitures) and then, through the use of expert judgment, identification of comparable generation assets that had been sold and sales prices announced. In many cases, this method produced much higher post-restructuring asset valuations than those produced by simulation models, perhaps because asset buyers were willing to pay premium prices to enter newly deregulated markets quickly.

receiving a share of the emissions allowance revenue, they may become more directly involved in the regulatory proceedings than occurred previously in the case of stranded costs. Further, if a fixed number of allowances were to be awarded to industry, it is possible that one would see the emergence of firms monitoring other firms and their respective claims for compensation. One way to imagine that the regulator could gain information about the expected performance of firms is a mechanism that enticed firms to reveal their own estimates. Policymakers could declare a default allocation rule that promises limited compensation to all firms, but then invite firms that are not happy with their allocation to justify a higher allocation within a structured process in which these firms bring information into a common, open-source simulation-modeling framework.

In any event, we imagine that for the firms to credibly appeal for compensation, it would likely involve simulation modeling. In this section, we assume the results of modeling are available to the regulator who seeks to target the allocation of emissions allowances in order to achieve a compensation goal by compensating only losing firms. Were this possible, we find that among the six competitive regions the portion of allowance value necessary to compensate the losers varies from 12% in ECAR (the Ohio Valley region) to 40% in MAIN (centered around Illinois) and in New York. The ECAR region has the largest amount of coal in the nation, but paradoxically this means that producers need a smaller share of allowance value for compensation because coal-fired generation sets the marginal cost and electricity price more often in this region. Consequently, the change in the opportunity cost of generation at the margin is more likely to reflect the constraint on carbon emissions, and consumers are more likely to see this as an increase in electricity price than in other regions where there is less coal generation. Table G indicates that the net effect of this decentralized approach to compensation results in 23% of the allowances needed for compensation, about equal to the 22% needed under a federal approach.

Again, in all these cases the overall market value of the industry would increase relative to the baseline because many firms that are winners would retain their gain in value and the allocation ensures that no firms would lose value. Table G reports the net increase in the market value of the industry when compensation is delivered federally, including the 22 percent of emissions allowance value, to be $7.5 billion.[13] We would expect that if compensation were delivered on a regional basis the net gain in market value would be greater, because there would be some portions of a firm's portfolio that lost value in one region even when other portions of the firm's portfolio gained value in another region. At the federal level these values would be somewhat offsetting. Indeed, we find that the industry gains value in every region, and in the aggregate the net increase in the value of the industry would be $8.5 billion.

7.2. Incomplete Information: Compensation Based on Facility Fuel Use

In practice, the regulator may not have information about the financial performance of firms and may not be able or willing to gain this information through the regulatory process. Therefore, we consider the case when the regulator cannot differentiate firms that gain value from firms that lose value. Nonetheless, the regulator

[13] As noted previously, this differs slightly from the results in Table B and Figure 1 because Table G includes just 182 firms.

has information based on readily observable characteristics of firm portfolios of generating capacity and historic generation that can be used to differentiate among firms. For instance, the most obvious distinction is the type of fuel used by various facilities. By targeting free allocation to individual facilities at rates that vary based on fuel use the regulator can compensate firms at different rates.

The mathematical problem is to find allocation rules that minimize the free allocation of allowances necessary to compensate every firm for any losses incurred under an allowance auction. Formally, the problem is to identify allocation rates, r_j , defined as allowances per MWh of 1999 generation, by fuel type j, where j refers to coal, gas, oil, that minimizes the value of the allowances that are allocated for free:

$$\min_{r_C, r_G, r_O} P^* \left[\sum_{f=1}^{F} r_C C_f + r_G G_f + r_O O_f \right] \text{ such that } \forall f \in F: P^* \left[r_C C_f + r_G G_f + r_O O_f \right] \geq \theta (V_f^{BL} - V_f^{A})$$

where P^* is the discounted weighted average CO_2 allowance price (1999\$ / ton CO_2), F is the set of firms $\{f\}$. C_f, G_f *and* O_f stand for 1999 generation (MWh) with coal, gas and oil, respectively, for firm f. V^A_f is the net present value of firm f under an auction (1999\$), and V^{BL}_f is the net present value of firm f in the baseline (1999\$). The parameter θ is the compensation target that can vary between zero and one ($0< \theta <1$) and represents the portion of market value in the absence of the program that must be maintained for all firms. For instance, if $\theta=1$ then the solution will provide full compensation to the most disadvantaged firm, implying that other firms gain in market value under the program.

Under this approach to defining compensation rules, usually there is one firm that just breaks even for each fuel category and thereby determines the allocation rule. These break-even firms are typically small firms with an idiosyncratic, unbalanced portfolio of assets. Often, to achieve full compensation these firms require a very high rate of allowances per MWh of generation in 1999, which leads to massive overcompensation of the other firms that also receive allowances at the same rate. Thus, in these cases this one firm was deemed outliers and removed from the analysis and the allocation rules by fuel type are recalculated. The recalculated number of allowances required for compensation is divided by the total number of allowances under the cap over the period 2010-2030 to obtain the percentage of the allowances pool that must be given away.

7.2.1. Accounting for Fuel Characteristics

The allocation rules that we identify are differentiated by fuel type so that, for example, gas and coal fired generators receive a different amount of allowances per MWh of historical generation. There is regulatory precedent for differentiating allowance allocation by fuel type in order to compensate firms differentially. Under EPA’s Clean Air Interstate Rule (CAIR), NO_x allowances are allocated to coal-fired generators at the rate of 1 times the total number of NO_x allowances divided by the fuel adjusted total average annual heat input between 1999 and 2002. Under CAIR, gas fired generators receive allowances at a rate that is 40% of the coal-fired rate (per BTUs of total historic heat input) and oil-fired generators receive allowances at 60% of the coal-fired rate.

If implemented at the federal level, differentiation by fuel type requires 100% of allowances to be given away for free to achieve compensation. To achieve this outcome requires coal generation to be compensated at a rate of 45.06 allowances per MWh of generation in 1999, oil generation receives none, and natural gas generation is compensated at 50.35 allowances per MWh. To put these numbers in perspective, firms would be compensated at a rate of 21.4 allowances per MWh of 2010 baseline generation under the historic allocation where all fossil generation was treated the same. The incomplete information about the performance of firms leaves the industry with a net gain in market value of $61 billion as a result of the compensation strategy. These numbers are summarized in Table H under the Federal Approach, Incomplete Information under the heading “Fuel” as the Compensation Metric. Even though the use of fuel for the compensation metric requires that 100% of the allowances be given away, the net gain to the industry is less than under free allocation through direct grandfathering of allowances. For the 182 firms included in Table H, the net gain to the industry from free allocation is $65 billion.[14] These policies are different because free allocation through allocation to firms based on historic heat input (grandfathering) leads to a different level of consumption overall, compared to upstream allocation or an auction. This accounts for the difference of $4 billion in the value of the industry as firms in competitive regions gain value if consumption increases in regulated regions.

<Table H about here>

A different approach to allocation of emission allowances would be to apportion the allowances to the states, much as it is done under the NO_x SIP Call trading program or to Member States in the EU Emission Trading System, and then let states determine the allocation in order to achieve compensation goals and other policy objectives. Were the strategy of basing compensation on fuel type of individual facilities implemented at the regional level a very different solution could be obtained. We assume that at the state or regional level the regulator has information about the performance of generation facilities within that region only, and therefore develops allocation rules based on fuel in order to compensate the worst off firm in that region, based on that firm’s portfolio of generation assets in that region.[15]

Table G reports that the portion of allowances that would need to be distributed would range from 27 percent in ECAR to 220 in MAAC, 209 percent in New York and 125 percent in New England. In these three regions it would not be possible to achieve compensation through free allocation based on fuel type were the states apportionment equal to that facilities in the region would receive under historic (grandfathering) allocation. Therefore we assume there is a reduction in the apportionment to other regions

[14] Table C indicates that for the full universe of firms the gain in value for the entire industry is $68 billion.
[15] The rates at which incumbent facilities are compensated in each region for this and the subsequent cases that are discussed are reported in Appendix Table A.

that is sufficient to achieve full compensation for every region. This is somewhat analogous to the universal service charge for long distance telephone service or rural free delivery for the postal service, in which regional cross-subsidies were implemented to achieve network externalities. In the aggregate, the decentralized approach requires 71 percent of the allowance value in the competitive regions to be given away for free to achieve compensation. In this case the industry gains $41 billion in value.

The comparison of the federal with the regional approach yields the potentially important insight. Compensation can be more efficiently delivered at the regional level when using a simple rule that differentiates fuel type. This approach reduces the amount of overcompensation to the industry by $19.7 billion, and frees up about 29% of the allowances for distribution through auction.

7.2.2. Accounting for Fuel and Technology Characteristics

In addition to differentiating by fuel type, we explore other variations on the compensation rule by incrementally adding more information. The next piece of information we add is information about the percent of nonemitting generation that is part of the portfolio of each firm. Heretofore, we assumed that nonemitting sources do not qualify for an allocation. However, we expect that firms that own nonemitting generation realize an increase in value from those assets and hence are unlikely to need as much compensation as firms that have a less balanced portfolio. By adjusting the allocation based on the portion of the firm's generation portfolio that is nonemitting, we find we reduce the overcompensation that accrues to many firms.

The third pair of columns in Table G combines the allocation to firms by fuel type with an adjustment in proportion with their share of generation in the region that is nonemitting ("clean"). This adjustment is fairly potent and reduces the percentage of the allowances to be given away for free to 87 percent when implemented at the federal level. The net market value of the industry would increase by $52 billion. If this approach were implemented at the regional level instead of the federal level, it would again lead to a significant difference. At the regional level compensation would require 63 % of the emission allowances in competitive regions to be allocated to achieve compensation. In this case the market value of the industry would increase by $36 billion.

Another piece of incremental information that we consider is the type of natural gas technology (turbine, steam and combined cycle). The fourth pair of columns in Table G assumes that the regulator can differentiate among natural gas technologies, treating combustion turbines, steam, and combined cycle as classes of facilities deserving different allocation rules, and that the regulator combines this information with information about fuel. At the federal level this information by itself provides almost no value. The percent of allowances required for compensation is 99%, comparable to 100% in the absence of information about gas technology. However, at the regional level this information provides considerable value. The percent of allowances required for compensation falls to 45%, and the net gain in market value for the industry falls to $23 billion.

The fifth pair of columns in Table G combines all this information. It assumes that the regulator can differentiate among natural gas technologies, treating combustion turbines, steam, and combined cycle as classes of facilities deserving different allocation rules, as well as use information about fuel and the percentage of generation that comes from non-emitting sources. At the federal level this still requires that 85% of the allowances be given away for free.

However, across the regions the combination of fuel and technology information reduces that percentage to 39%, and it reduces the gain in market value for the industry to under $20 billion. There remains one region – New York – where full compensation of the worst off firm cannot be achieved. However, for the nation as a whole this approach leaves 61% of the allowance value available for other purposes.

In summary, we find that making use of information about facility-specific fuel and technology in constructing a compensation strategy with the goal of compensating the worst off firm provides only modest value at the federal level. However, if implemented at the regional level, significantly greater efficiency in the design of compensation can be achieved if regulators were to take advantage of facility-specific information.

7.3. Incomplete Information: Compensation Based on a Firm's Emission Rate

Another type of information that can be used to develop targeted compensation rules is the CO_2 emission rate. The emission rates of facilities are closely related to their fuel use and directly affect the cost of compliance with the policy. Emission rate information is readily available or for all emitting fossil-fired facilities greater than 25 MW through the EPA's continuous emission monitoring. Since the firm represents a portfolio of facilities, we examine how well the change in the market value of the firm correlates with the firm-level emission rates, and we find a strong correlation.

Figure 5 displays the relationship of the estimated change in market value ($/MWh) with upstream allocation to the average emission rate (tons CO_2/MWh) for the largest 182 firms operating in competitive regions. The changes in market value for the firm that occur in the model simulation are divided by total generation across the facilities operated by the firm in 2010 of the baseline scenario. The average CO_2 emission rate for firms is calculated from the baseline emissions and generation of the facilities in the firm's portfolio in 2010. Systematically we find the loss in market value per MWh of generation increases with the baseline emission rate. With upstream allocation, 57 of the firms gain value and 125 lose value. An ordinary least squares regression indicates the average emission rate contributes importantly to the change in market value (R^2=0.62). The estimated threshold emission rate at which firms are expected to break-even is 0.52 tons/MWh. The estimated change in market value per change in emissions, or in other words the slope of the solid line in Figure 5, is $37.47 per ton (1999$). This coefficient is significant at the 99% level.

We use this information to calculate a formula to guide free allocation. We assume firms receive allowance value equivalent to $37.47 per ton of emissions from their portfolio of incumbent facilities (including facilities owned by these firms under construction up to the present), but only firms with an average emission rate in excess of the threshold receive compensation. An alternative way to view this approach is that for those firms for an emission rate in excess of the threshold we use the regression equation and the firm's emission rate in 2010 under the baseline scenario to predict the compensation rate per MWh of generation in the baseline in 2010. Table H reports for the “Fit” case that the amount of free allocation necessary to compensate all eligible firms using this formula is 27% of the allowances. The result leaves 101 firms as winners, with a gain in value of $13.85 billion, and 81 firms as losers, with a loss of $2.59 billion.

The number of firms losing value can be reduced through more generous allocation so that virtually every firm is compensated, as reported in the “Full” case in Table H. We accomplish this full compensation for all but five firms, including one outlier firm, by reducing the threshold to 0.09 tons/MWh. The upper dashed line in Figure 5 shows this example. We find that 65% of the allowances must be given away, leaving 35% available for auction. This leaves five firms with losses of $120 million, while the industry as a whole gains value of $36.7 billion. Finally, we consider an intermediate result with the threshold emission rate at which a firm qualifies for compensation set to 0.31 tons/MWh. The intermediate case yields a gain in market value of $23 billion for the industry, and requires that 45% of the allowances be given away for free. The middle dashed line in Figure 5 illustrates the intermediate case.

7.4. Overview of Compensation Strategies

If regulators lack complete information to be able to anticipate the performance of firms, or are unable to distinguish allocation rules directly on the basis of this performance, then they can use readily available information to design consistent compensation rules that proxy as a way to compensate losing firms. How well this proxy is achieved depends whether a federal or regional approach is adopted. If regions/states are assigned emission budgets and apportioned emission allowances, they can achieve full compensation using facility-level information. Moreover, because there is less heterogeneity at the regional level than at the national level, the regions can achieve compensation goals much more efficiently than can be achieved from the federal level. At the regional level, facility-specific information can enable full compensation to be achieved with 39% of the emission allowances. This approach leaves a net gain in the industry of $19.5 billion.

However, if allocation remains the purview of federal policy then information about firm-level emission rates would be much more efficient than facility-level information in achieving compensation goals. At the federal level, full compensation could be achieved with 65% of emission allowances. This approach leaves a net gain in the industry of $36.7 billion

On the other hand, if regulators can obtain and act on information about the expected performance of firms then regulators could compensate losers directly without providing compensation to winners. In this case, it would be sufficient to give away just 22% of the emission allowances for free. This approach still leaves a net gain in the industry of $7.51 billion.

8. The Compensation Goal

We have maintained a 100 percent compensation goal for the most disadvantaged firms as a yardstick for comparing the different approaches to the distribution of allowances. Let us denote the share of the value of allowances that must be given away for free to achieve this goal as *S*. In reality, the regulator may decide on a goal that differs from 100 percent compensation. The estimates we provide can be adjusted in a linear way for any goal. For a compensation target less than 100 percent, that is for $\theta < 1$, the value of allowances necessary to achieve that goal is $\theta \bullet S$.

Several factors influence the compensation goal (θ). Hochman (1974) argues that individual behavior presumes the permanence of preexisting rules and dealing equitably with those who suffer windfall losses may be crucial to preserving a belief in the fairness of social rules and institutions. On the other hand, investors in a competitive market are expected to anticipate uncertainties and factor them into account. Some policy changes have a positive effect and some have a negative effect on investments, and some observers argue that society is better off in the absence of compensation.[16] For the most part, investors retain the payoff when gains exceed expectations, although sometimes regulators or legislators intervene to prevent taking of profits, as in recent decisions in Maryland and elsewhere to allow consumers to phase in adjustments in electricity rates when rate caps that survive from industry restructuring will be lifted. Fairness and efficiency may be served by a symmetric process in which the regulator relieves the firm of some but perhaps not all responsibility for changes in policy that impose large loss in value. Inevitably, the final outcome will be shaped as much by political necessity as by compensation principles, but information about those principles can help inform the policy dialogue.[17]

The emergence of climate policy may have been anticipated years ago—perhaps with the signing of the Kyoto Protocol or at some other point in time at which changes in policy could have been anticipated. The time between when a policy is announced and when it is implemented gives firms that are to be regulated time to adjust their investment plans so as to avoid new investments that would be particularly disadvantaged under the forthcoming policy and to make investments that will perform better under the policy. To the extent that the loss in economic value stems from investments made between the announcement and implementation of the policy, this advance warning diminishes the claim for harm. Most investments since the early 1990s were in natural gas generation technologies, some of which gain value and some of which lose value due to the policy.

A second aspect to delay is that it may allow for the continued realization of economic value from investments that predate the policy. As a consequence, the lost economic value will be less than if the policy were implemented in the same year it is announced because for the intervening years the owner will continue to incur revenues and costs equivalent to those in the baseline. Therefore, the need for compensation will be less if implementation occurs sometime after the adoption of the policy. However, although delay reduces the harm, it does not directly affect the compensation target (as a share of harm that is to be compensated) or the share of allowance value necessary to achieve that target.

[16] For example, Polinsky (1972) suggests that a single policy should be viewed as part of a larger social agenda in which government pursues many policies to improve the welfare of society generally.
[17] A "public choice" view is that appropriate compensation is discovered in a political market place, with bartering commencing in the form of political negotiations (Buchanan 1973). Compensation serves a practical purpose by this rationale, affecting a political buy-out of groups opposing changes in social policy (Tullock 1978).

To illustrate these points, we assume that the annual value of existing assets going forward is constant in every year *t* in the baseline (v^{BL}), and also constant at a reduced value under the auction policy (v^{A}). If the policy is adopted and implemented in the same year, the loss in value (L) is:

$$L = \sum_{t=0}^{\infty} \partial^t \left(v^{\mathrm{BL}} - v^{\mathrm{A}} \right) = \left(\frac{1}{1-\partial} \right) \left(v^{\mathrm{BL}} - v^{\mathrm{A}} \right).$$

Assume the discount factor is $\partial = 0.92$ corresponding to a discount rate 0.08. Then the instantaneous loss in the value of existing assets from the implementation of the policy is $L = (12.5)\left(v^{\mathrm{BL}} - v^{\mathrm{A}} \right)$. If implementation is delayed by five years after the adoption of the policy then the loss in value due to the policy is:

$$L = \sum_{t=5}^{\infty} \partial^t \left(v^{\mathrm{BL}} - v^{\mathrm{A}} \right) = (8.24)\left(v^{\mathrm{BL}} - v^{\mathrm{A}} \right).$$

The delay in implementation reduces the financial magnitude of harm by more than one-third. However, delay also reduces the present value of allowances measured at the time when the policy is adopted. Consequently, the portion of allowance value (*S*) required for full compensation is unchanged.

9. Conclusion

A CO_2 regulation implemented upstream can effectively be viewed as a CO_2 emissions tax from the perspective of the electricity sector. Whether producers or consumers of electricity bear the cost of the policy depends on whether generators are subject to cost-of-service regulation or sell power at market-determined prices. In regulated regions, the utility regulator is assumed to compensate generators for federally mandated environmental policy, at least in the long run. The major change in market value in the electricity industry is expected to occur in competitive regions.

The measurement of the impact on producers depends on the length of the yardstick used to measure harm. At the facility level, the financial loses cumulated by facility under the policy that we examine total to 1/3rd of the total present discounted value of the allowances created by one recent proposal. When viewed at the level of the industry, which has been the focus of previous studies, loses total just 1/16th of the allowance value. The target for compensation aimed at producers is the shareholder of the firm. This paper develops estimates of the claim for compensation at the firm level. We find that total claims on compensation by losing firms are roughly 11% of total allowance value. Moreover, many firms are winners, with a gain equivalent to 4% of the allowance value.

Consumer claims for compensation across regions depend on the fossil fuel intensity of the generating sector in the region, particularly in regulated regions. In the aggregate, consumer claims for compensation dwarf producer claims by a factor of almost 10 to 1. However, consumer claims for compensation are diffuse, and consequently they are less potent in the political context of carbon policy.

The previous usual approach to the initial distribution of emission allowances would be to distribute allowances for free to electricity generator firms according to a uniform formula based on historic emissions or heat input. This approach raises both distributional and efficiency issues. Uniform historic-based allocation will dramatically over compensate firms in the aggregate and is not well targeted to the firms with the largest losses. In particular, this approach will compensate firms in competitive regions and consumers in regulated regions. Historic-based allocation also diminishes the environmental effectiveness of the price-capped emissions trading policy in reducing CO_2 emissions because it dampens the price effect in regulated regions.

Determination of the best approach to compensating firms depends on whether compensation is to be accomplished at the state or federal level as well as the amount of information available to regulators. Determination of compensation will fall to regions/states if state jurisdictions are assigned emission budgets and apportioned emission allowances. At the regional or state level, regulators can achieve full compensation using facility-level information and do so more efficiently than could be done using similar rules at the federal level, because at the state level regulators can take advantage of the heterogeneity in costs and technology that disappears from the federal viewpoint. At the regional level, facility-specific information can enable full compensation to be achieved with 39% of the emission allowances. This approach leaves a net gain in the industry of $19.5 billion, and enables 61% of the value of emission allowances to be dedicated to purposes other than compensating electricity producers.

If allocation remains the purview of federal policy, then firm-level emission rates would be a much more efficient basis for compensation. At the federal level, full compensation using average emission rate information could be achieved with 65% of emission allowances. This approach leaves a net gain in the industry of $36.7 billion, and enables 35% of the allowance value to be directed elsewhere.

On the other hand, if regulators can obtain and act on information about the expected performance of firms then regulators could compensate losers directly without providing compensation to winners. In this case, it would be sufficient to give away just 22% of the emission allowances for free, preserving 78% of the allowance value. This approach still leaves a net gain in the industry of $7.51 billion.

This information indicates that compensation of the worst-off firm can be achieved for much less than 100% of the value of emission allowances, and to do so still leaves dramatic net gain in value for the industry. This information begs the question of the appropriate level of compensation. All of this analysis assumes that the compensation goal is 100%, but less than 100% compensation may be desirable for a variety of reasons. For instance, one factor that can lower the level of compensation is a delay between when a policy is announced and when it is implemented. A second factor may be the desire to limit compensation overall, especially since compensating firms has dramatic cost. With complete information and omniscient regulation, regulators could deliver $15 billion in compensation targeted to deserving parties for about $31 billion in allowance value. Under the more likely circumstance of incomplete information, but still with very well designed policies, the cost of achieving the $15 billion compensation target would be $55 billion if achieved at the regional level, or $71 billion if achieved at the federal level. As an option for federal policy, one compelling approach, given incomplete information, is to rely on the strong linear relationship between loses and emission rates identified through a simple regression. Using this approach leaves just $2.6 billion in losses spread across 81 firms in the industry, effectively erasing 83% of the losses from the policy. The cost of eradicating the remaining $2.6 billion is about $62 billion more in allowance value. These opportunity costs suggest practical limits on the amount of compensation that should be incorporated in climate policy.

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Table A: Comparison of EIA (2005b) and RFF modeling scenarios (1999$)

	2010	2015	2020	2025
EIA (2005b)				
Baseline				
Emissions (tons CO_2)	2.88	3.07	3.31	3.65
NCEP Policy				
Emissions (tons CO_2)	2.85	3.01	3.20	3.41
Allowance Price ($/ton)				
RFF Modeled Scenarios				
Baseline				
Emissions (tons CO_2)	2.76	2.92	3.10	3.37
Moderate Policy				
Emissions (tons CO_2)	2.67	2.83	3.01	3.19
Allowance Price ($/ton)	3.91	5.89	7.00	7.70
More Stringent Policy				
Emissions (tons CO_2)	2.52	2.60	2.71	2.89
Allowance Price ($/ton)	8.38	12.62	15.00	16.50

Table B. Moderate Policy: General results for the upstream allocation (no allocation to the electricity sector) with the standard mix of regulation and competition.

Year 2020 unless stated otherwise Values in 1999 dollars	**Competitive Regions**	**Regulated Regions**	**Nation**
Change in Electricity Price ($/MWh)	3.75	4.28	4.05
Annual Consumer Cost (billion $)	7.47	11.10	18.57
Baseline Generation (bill. kWh) and (Change from Baseline as %)	2,141 (-2.0%)	2,636 (-1.2%)	4,777 (-1.5%)
Coal	1,244 (-3.5%)	1,222 (-4.0%)	2,466 (-3.8%)
Gas	422 (-1.2%)	595 (+1.0%)	1,017 (+0.1%)
Oil	~0 (-44.2%)	0.2 (-53.4%)	0.2 (-52.8%)
Nonemitting	474 (+1.4%)	819 (+1.5%)	1,294 (+1.5%)
Annual Producer Cost (billion $)			
Industry Level	2.97	-	2.97
Firm Level*	3.43	-	3.43
Facility Level*	4.74	4.07	8.82
Total Producer Cost Loss in Market Value (NPV in 2006, billion $)			
Industry Level	9.00	-	9.00
Firm Level*	14.95	-	14.95
Facility Level*	23.41	26.57	49.98
CO_2 Tax Price ($)	7.00	7.00	7.00
Modeled CO_2 Emissions			
Baseline (bill. short tons) Reductions from Baseline	1.506 (0.049)	1.596 (0.045)	3.102 (0.094)
EIA forecast of CO_2 Emissions			
Baseline (bill. short tons) Reductions from Baseline			3.309 (0.112)
Annual Value of Emission Allowances	10.19	10.86	21.05
Total Value of Emission Allowances (NPV in 2006, billion $)	68.27	72.84	141.11

* Aggregation of losses excluding gains to winners.

Table C. Moderate Policy: 100% free allocation to electricity sector based on a historic measure of heat input by facility, standard mix of regulation and competition.

Year 2020 unless stated otherwise Values in 1999 dollars	**Competitive Regions**	**Regulated Regions**	**Nation**
Change in Electricity Price ($/MWh)	$4.07	$0.39	$1.95
Annual Consumer Cost (billion $)	8.10	1.01	8.98
Baseline Generation (bill. kWh) and (Change from Baseline as %)	2,141 (-1.8%)	2,636 (+0.2%)	4,777 (-0.7%)
Coal	1,244 (-2.9%)	1,222 (-4.0%)	2,466 (-3.4%)
Gas	422 (-2.2%)	595 (+6.3%)	1,017 (+2.8%)
Oil	~0 (-65.4%)	0.2 (-3.1%)	0.2 (-7.2%)
Nonemitting	474 (+1.4%)	819 (+2.0%)	1,294 (+1.8%)
Annual Producer Cost (billion $)			
Industry Level	-8.17	-	-8.17
Firm Level*	0.01	-	0.01
Facility Level*	0.11	2.81	2.93
Total Producer Cost Loss in Market Value (NPV in 2006, billion $)			
Industry Level	-68.11	-	-68.11
Firm Level*	0.11	-	0.11
Facility Level*	1.44	17.76	19.20
CO_2 Tax Price ($)	7.00	7.00	7.00
Modeled CO_2 Emissions			
Baseline (bill. short tons) Reductions from Baseline	1.506 (0.044)	1.596 (0.031)	3.102 (0.076)
EIA forecast of CO_2 Emissions in electricity sector (bill. short tons)	***Not modeled by EIA***		
Annual Value of Emission Allowances	10.23	10.95	21.18
Total Value of Emission Allowances (NPV in 2006, billion $)	68.55	73.60	142.15

Table D. Annual Compensation and Percent of Annual Losses Compensated with 100% Free Allocation: Effect on electricity producers and consumers of 100% free allocation to electricity generators relative to upstream allocation.

Year 2020 (Billion $)	**Producers**	**Consumers**
Competitive Regions	$11.14* (375%)	$-0.63 (-8%)
Regulated Regions	----	$10.09 (91%)

*The estimate includes both producers who were losers and winners under upstream allocation.

Table E. The effect of different levels of free allocation on the cost for producers and consumers for a single year.

	Producers Cost*			**Producer Gain****	**Consumers Costs**			**Total**
Year 2020 (Billion $)	Competitive Regions	Regulated Regions	Nation	Nation	Competitive Regions	Regulated Regions	Nation	Nation
Upstream Allocation	3.43	-	3.43	(+) 0.46	7.47	11.10	18.57	21.54
Mix of Allocation (20% given to electricity sector)	1.50	-	1.50	(+) 1.32	8.10	9.04	17.12	17.30
Free Downstream Allocation	0.01	-	0.01	(+) 8.26	8.10	1.01	8.98	0.73

*Producer cost measures losses in 2020 among firms the suffer loss in market value.
**Producer gain measures gain in 2020 among firms that increase market value. Note sign on gain is opposite of cost.

Table F. More Stringent Policy: General results for the upstream allocation (no allocation to the electricity sector) with the standard mix of regulation and competition.

Year 2020 unless stated otherwise Values in 1999 dollars	**Competitive Regions**	**Regulated Regions**	**Nation**
Change in Electricity Price ($/MWh)	11.88	9.38	10.45
Annual Consumer Cost (billion $)	23.36	24.12	47.43
Baseline Generation (bill. kWh) and (Change from Baseline as %)	2,141 (-7.8%)	2,636 (-0.2%)	4,777 (-3.6%)
Coal	1,244 (-21.5%)	1,222 (-15.1%)	2,466 (-18.3%)
Gas	422 (+8.9%)	595 (+12.7%)	1,017 (+11.1%)
Oil	~0 (+97.7%)	0.2 (-18.1%)	0.2 (-10.4%)
Nonemitting	474 (+13.5%)	819 (+12.6%)	1,294 (+12.9%)
Annual Producer Cost (billion $)			
Industry Level	-0.96	-	-0.96
Firm Level*	7.87	-	7.87
Facility Level*	5.31	8.83	14.14
Total Producer Cost Loss in Market Value (NPV in 2006, billion $)			
Industry Level	-8.95	-	-8.95
Firm Level*	39.76	-	39.76
Facility Level*	32.25	59.59	91.84
CO_2 Tax Price ($)	15.00	15.00	15.00
Modeled CO_2 Emissions			
Baseline (bill. short tons) Reductions from Baseline	1.506 (0.252)	1.596 (0.137)	3.102 (0.390)
EIA forecast of CO_2 Emissions			
Baseline (bill. short tons) Reductions from Baseline			3.309 (0.112)
Annual Value of Emission Allowances	18.80	21.88	40.68
Total Value of Emission Allowances (NPV in 2006, billion $)	128.58	147.60	276.18

* Aggregation of losses excluding gains to winners.

Table G. Allocation using simple rules at the federal or region/state level.

	Complete Information		**Incomplete Information Using Simple Rules**							
			Fuel Type		***Fuel + Clean***		**Fuel + Gas Technology**		**Fuel + Clean +Gas Technology**	
Units are percent and billion 1999$	*Percent Free Allocation	Net Gain in Market Value	*Percent Free Allocation	Net Gain in Market Value	*Percent Free Allocation	Net Gain in Market Value	*Percent Free Allocation	Net Gain in Market Value	*Percent Free Allocation	Net Gain in Market Value
Federal Approach	22%	7.51	100%	60.72	87%	52.13	99%	59.99	86%	51.51
Regional/ State Approach										
ECAR	12%	1.74	27%	6.29	24%	5.63	27%	6.29	24%	5.63
ERCOT	25%	0.385	45%	2.56	37%	1.69	45%	2.50	37%	1.65
MAAC	34%	1.09	220%	15.61	193%	13.56	71%	3.97	54%	2.69
MAIN	40%	3.00	76%	7.44	70%	6.65	53%	4.64	48%	4.00
NY	40%	1.47	209%	5.96	187%	5.36	143%	4.20	130%	3.85
NE	21%	0.832	125%	3.18	117%	3.01	60%	1.72	56%	1.63
Aggregate Regions	23%	8.52	71%	41.04	63%	35.90	45%	23.32	39%	19.45

*Percent of allowances from competitive regions only.

Table H. Summary of Federal and Regional/State Approaches to Compensation for 182 firms.

	Federal Approach								Regional Approach				
Information:	n/a	Complete	Incomplete						Complete	Incomplete			
Compensation Metric:			Facility-Level Fuel / Technology:				Emission Rate -Firm:			Facility-Level Fuel / Technology:			
	Free*	Firm Value	**Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**	**Fit**	**Full**	Firm Value	**Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation (tons per MWh)													
Coal	--	--	45.06	45.06	45.06	45.06	--	--	--				
Oil	--	--	0	0	0	0	--	--	--				
Gas (all)	--	--	50.35	50.35	--	--	--	--	--				
Gas steam	--	--	--	--	15.10	15.10	--	--	--				
Gas CC	--	--	--	--	50.35	50.35	--	--	--				
Gas CT	--	--	--	--	0	0	--	--	--				
Threshold Emission (tons per MWh)	--	--	--	--	--	--	0.52	0.09	--				
Allocation ($ per ton)	--	--	--	--	--	--	37.47	37.47	--				
# Winners	180	182	182	180	182	180	101	177					
Gain (billion $)	65.08	7.51	60.72	52.14	59.99	51.52	13.85	36.67					
# Losers	2	0	0	2	0	2	81	5					
Loss (billion $)	0.005	0	0	0.011	0	0.011	2.59	0.012					
Industry Net (billion $)	65.07	7.51	60.72	52.13	59.99	51.51	11.26	36.66	8.52	41.04	35.90	23.32	19.45
(%) Free Allowances	100	22	100	87	99	86	27	65	23	71	63	45	39

*Free allocation of 100% of allowances is described in Table C, and leads to a different level of emissions, etc. than upstream allocation.

Figure 1. Firms own a portfolio of facilities that lose and gain value. The level of aggregation in the electricity industry determines the claim for compensation as a share of emission allowances (billion 1999 dollars, NPV in 2006).

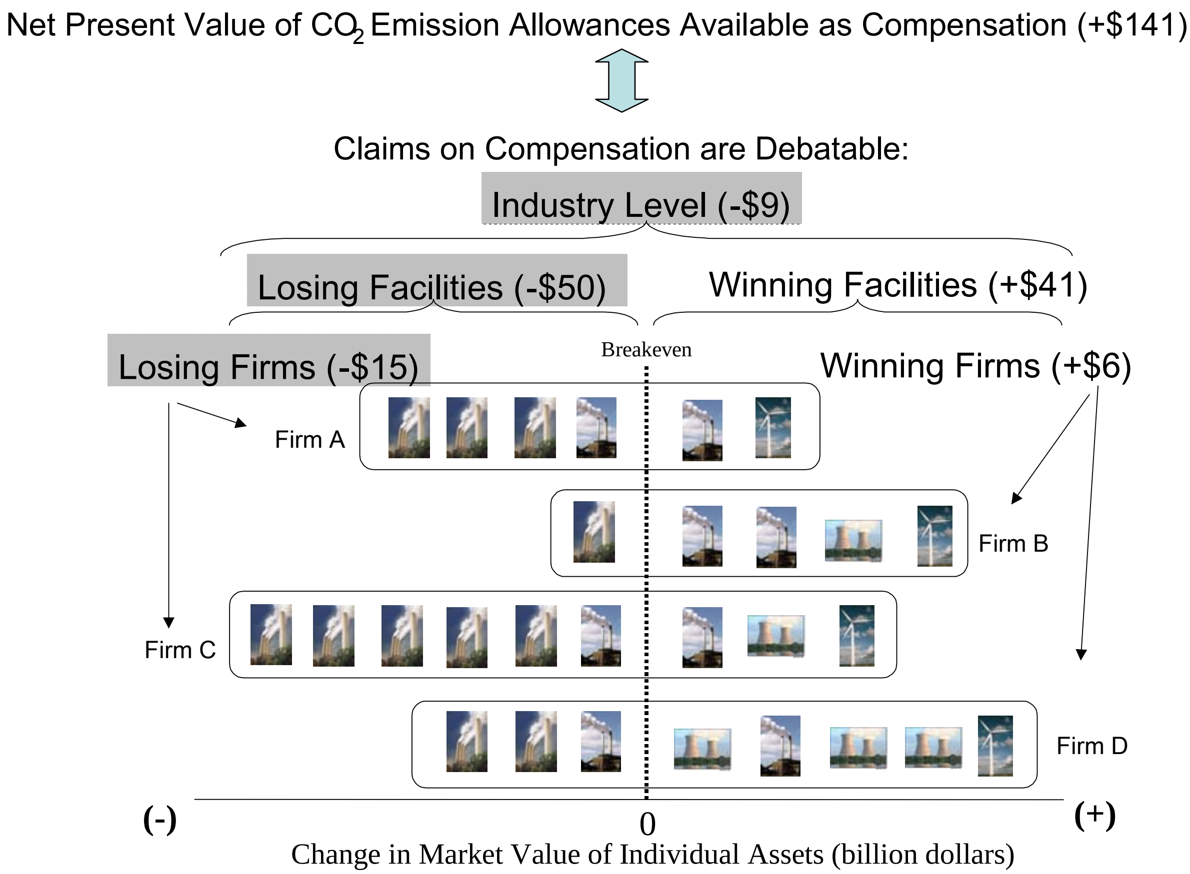


Figure 2. Distribution of change in electricity price sorted by regulated and competitive regions under two approaches to allocation. Panel A represents upstream allocation (no allocation to electricity sector) and Panel B represents free allocation to electricity sector. Only customers in regulated regions benefit from free allocation.

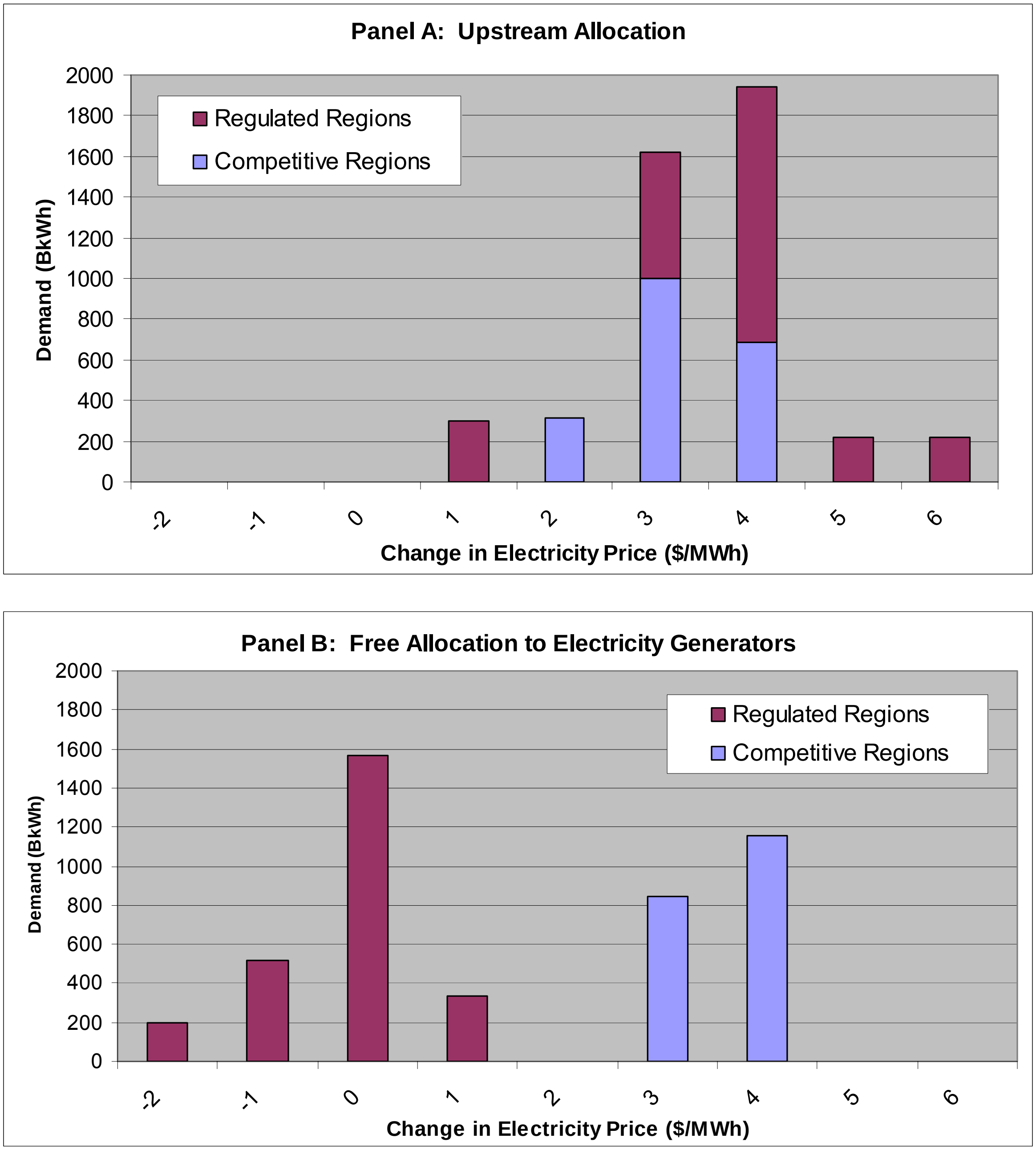


Figure 3. Distribution of costs among generators under upstream allocation (no allocation to electricity sector) and free allocation to electricity sector. The data includes the holdings in competitive regions of 81 firms.

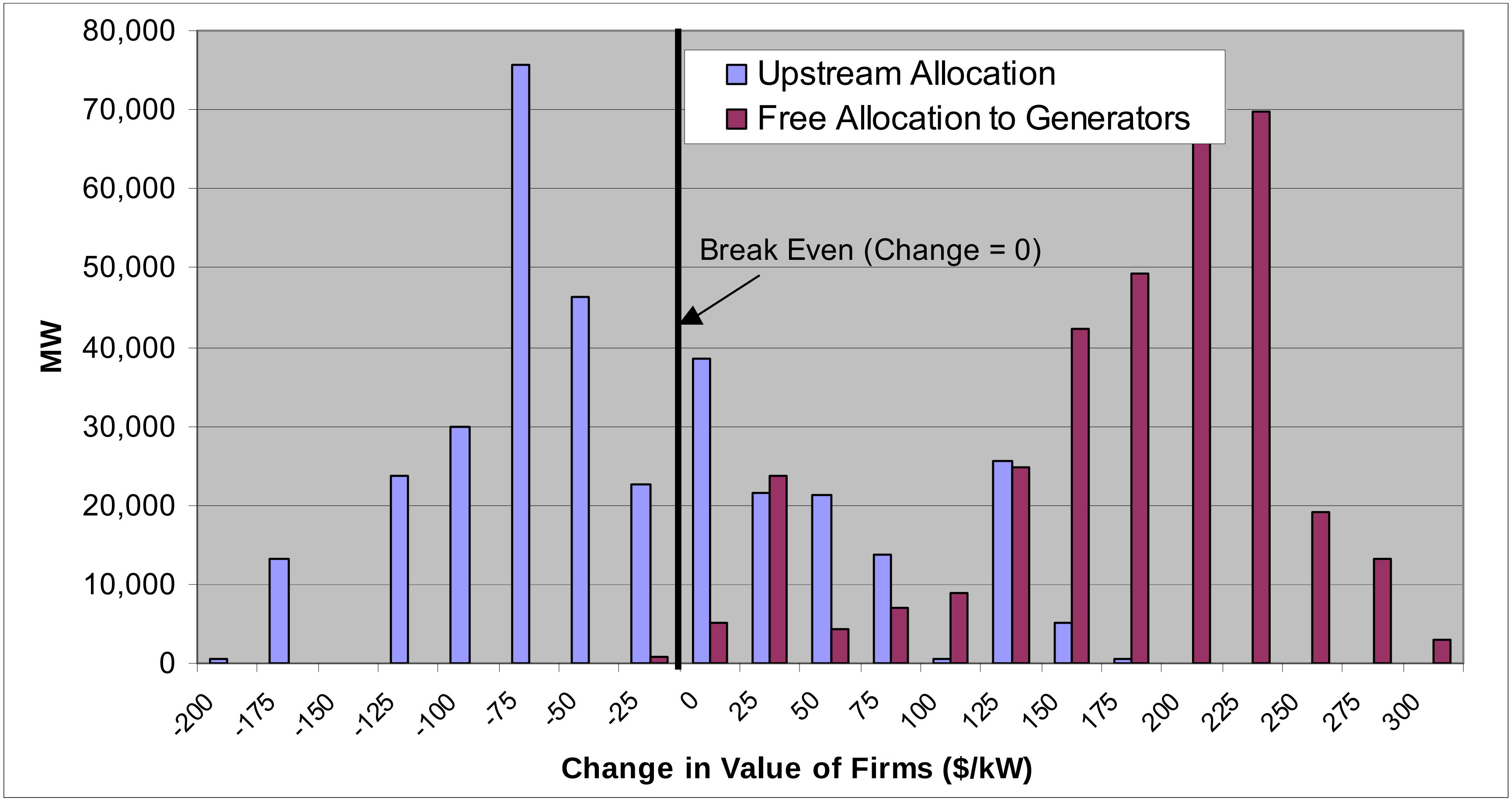
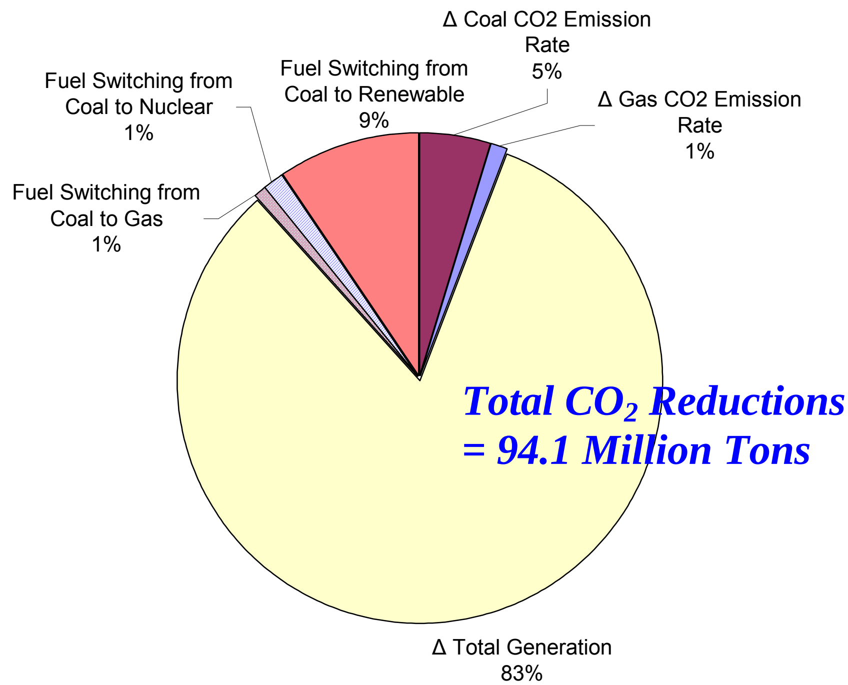


Figure 4. Sources of CO2 Emission Reductions from Electricity Vary with Allocation Approach (results for 2020)

Panel (A) Upstream Allocation



Panel (B) Free Allocation

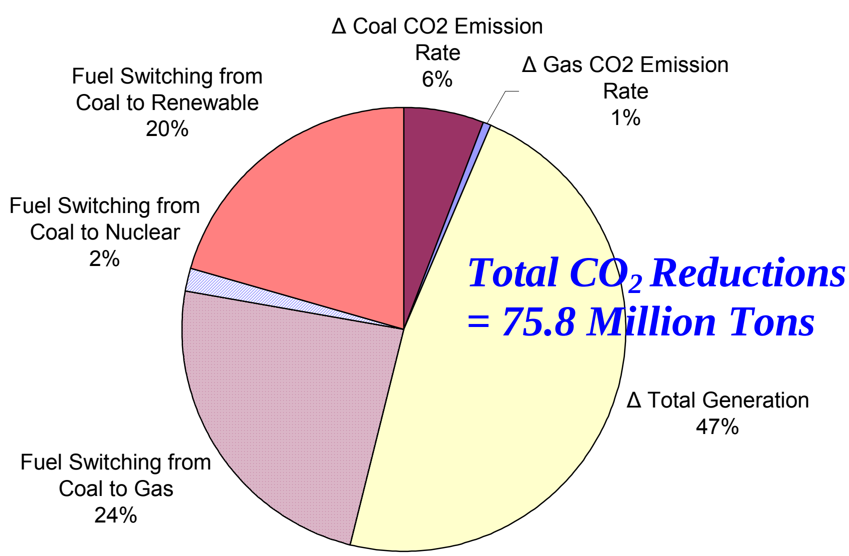
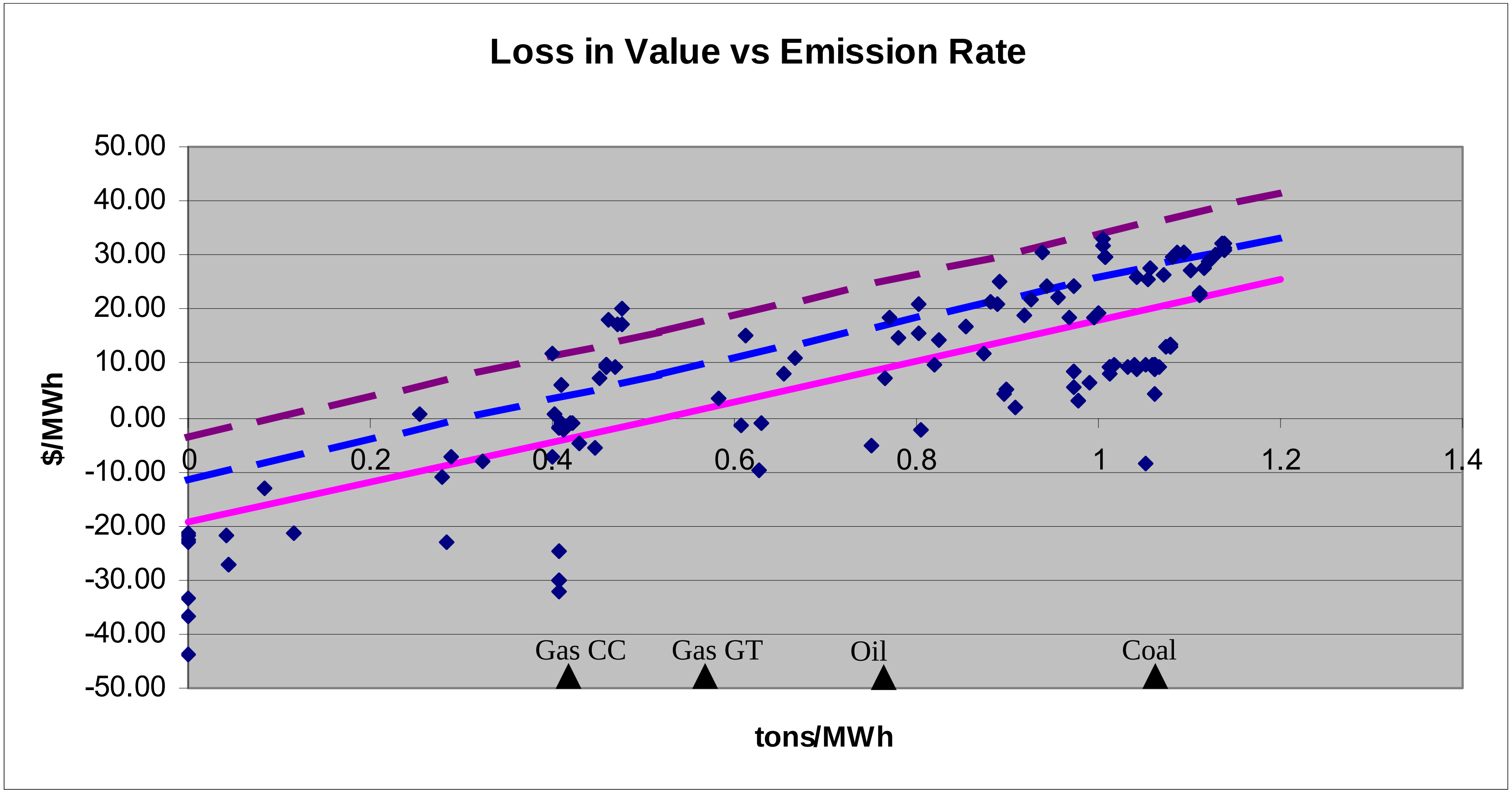


Figure 5. Change in the market value of 182 firms operating in competitive regions under upstream allocation/auction per MWh of operation as forecast in the baseline in 2010, compared to the firms' average emission rate for existing facilities as forecast for 2010. Also indicated are average emission rates in competitive regions for four classes of technology.



Appendix Table A1: Regional approach by regions

	ECAR				
Information:	Complete	Incomplete			
Compensation Metric:	Firm Value	Generation Fuel / Technology: **Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation rate (tons per MWh)					
Coal		13.50	13.50	13.50	13.50
Oil		0	0	0	0
Gas (all)		0	0	--	--
Gas (steam)		--	--	0	0
Gas CC		--	--	0	0
Gas CT		--	--	0	0
# Winners	70	70	70	70	70
Gain (billion $)	1.74	6.29	5.63	6.29	5.63
# Losers	0	0	0	0	0
Loss (billion $)	0	0	0	0	0
Industry Net (billion $)	1.74	6.29	5.63	6.29	5.63
Free Allowances (%)	12%	27%	24%	27%	24%

	ERCOT				
Information:	Complete	Incomplete			
Compensation Metric:	Firm Value	Generation Fuel / Technology: **Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation rate (tons per MWh)					
Coal		32.29	32.29	28.80	28.80
Oil		0	0	0	0
Gas (all)		5.24	5.24	--	--
Gas (steam)		--	--	55.72	55.72
Gas CC		--	--	5.24	5.24
Gas CT		--	--	0	0
# Winners	49	49	47	49	48
Gain (billion $)	0.385	2.56	1.70	2.50	1.65
# Losers	0	0	2	0	1
Loss (billion $)	0	0	0.01	0	0
Industry Net (billion $)	0.385	2.56	1.69	2.50	1.65
Free Allowances (%)	25%	45%	37%	45%	37%

	MAAC				
Information:	Complete	Incomplete			
Compensation Metric:	Firm Value	Generation Fuel / Technology: **Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation rate (tons per MWh)					
Coal		36.87	36.87	36.87	36.87
Oil		0	0	0	0
Gas (all)		571.3	571.3	--	--
Gas (steam)		--	--	0	0
Gas CC		--	--	7.34	7.34
Gas CT		--	--	1,528	1,528
# Winners	35	35	34	35	33
Gain (billion $)	1.09	15.61	13.56	3.97	2.69
# Losers	0	0	1	0	2
Loss (billion $)	0	0	0.004	0	0.004
Industry Net (billion $)	1.09	15.61	13.56	3.97	2.69
Free Allowances (%)	34%	220%	193%	71%	54%

	MAIN				
Information:	Complete	Incomplete			
Compensation Metric:	Firm Value	Generation Fuel / Technology: **Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation rate (tons per MWh)					
Coal		31.97	31.97	31.97	31.97
Oil		0	0	0	0
Gas (all)		360.8	360.8	--	--
Gas (steam)		--	--	0	0
Gas CC		--	--	0	0
Gas CT		--	--	360.8	360.8
# Winners	35	35	35	35	35
Gain (billion $)	3.00	7.44	6.65	4.64	4.00
# Losers	0	0	0	0	0
Loss (billion $)	0	0	0	0	0
Industry Net (billion $)	3.00	7.44	6.65	4.64	4.00
Free Allowances (%)	40%	76%	70%	53%	48%

	NY				
Information:	Complete	Incomplete			
Compensation Metric:	Firm Value	Generation Fuel / Technology: **Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation rate (tons per MWh)					
Coal		27.55	27.55	27.55	27.55
Oil		640.1	640.1	640.1	640.1
Gas (all)		132.6	132.6	--	--
Gas (steam)		--	--	132.6	132.6
Gas CC		--	--	70.72	70.72
Gas CT		--	--	85.90	85.90
# Winners	53	53	51	53	51
Gain (billion $)	1.47	5.96	5.36	4.20	3.85
# Losers	0	0	2	0	2
Loss (billion $)	0	0	0	0	0.001
Industry Net (billion $)	1.47	5.96	5.36	4.20	3.85
Free Allowances (%)	40%	209%	187%	143%	130%

	NE				
Information:	Complete	Incomplete			
Compensation Metric:	Firm Value	Generation Fuel / Technology: **Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation rate (tons per MWh)					
Coal		36.03	36.03	26.03	26.03
Oil		0	0	0	0
Gas (all)		53.34	53.34	--	--
Gas (steam)		--	--	0	0
Gas CC		--	--	19.95	19.95
Gas CT		--	--	53.34	53.34
# Winners	29	29	26	29	26
Gain (billion $)	0.832	3.18	3.02	1.72	1.65
# Losers	0	0	3	0	3
Loss (billion $)	0	0	0.011	0	0.018
Industry Net (billion $)	0.832	3.18	3.01	1.72	1.63
Free Allowances (%)	21%	71%	63%	45%	39%