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Abstract

We investigate the cost-effectiveness and distributional effects of a revenue-raising auction, grandfathering, and a generation performance standard as alternative approaches for distributing carbon emission allowances in the electricity sector. We solve a detailed national electricity market model and find the auction is roughly one-half the societal cost of the other approaches. This result holds under a variety of assumptions about the future state of economic regulation and competition in the electricity sector. The differences in the cost of the approaches flow from the effect of each approach on electricity price. Grandfathering is the best for producers but it imposes a substantial cost on consumers. The generation performance standard yields the lowest electricity price but highest natural gas price. The auction does better than the generation performance standard at protecting households and at preserving asset values for producers. It also yields revenues that can help meet other efficiency and distributional goals.

Key Words: carbon, emission allowance trading, allowance allocations, electricity, restructuring, air pollution, safety valve, auction, grandfathering, generation performance standard, output-based allocation, cost-effectiveness

JEL Classification Numbers: Q2; Q25; Q4; L94

Summary

We investigate the cost-effectiveness and distributional effects of three alternative approaches for distributing carbon emission allowances under an emission-trading program in the electricity sector. One is a revenue-raising "auction." The auction could be coupled with a cap on the maximum price for allowances, also known as a "safety valve," which has become known as the Sky Trust proposal. The second is "grandfathering," patterned after the sulfur dioxide (SO_2) trading program, which would allocate allowances on the basis of historic generation. A third is a "generation performance standard," embodied in current legislative proposals and nitrogen dioxide (NO_x) policy in Sweden, which would update allowance allocations based on shares of current electricity generation. We solve a detailed national electricity market model and measure the economic cost of each allocation scheme, as well as the distributional effects felt by consumers and producers.

Our main finding is that the auction is dramatically more cost-effective than the other approaches—roughly one-half the societal cost of grandfathering or the generation performance standard. This result holds under a variety of assumptions about the future state of economic regulation and competition in the electricity sector. Accounting for changes outside the electricity sector that result from changes in relative fuel costs reinforces the differences among the three approaches.

The differences in the cost of the three approaches flow from the effect of each approach on electricity price. The generation performance standard allocation (on the basis of generation) constitutes an incentive to increase electricity generation. This incentive resembles an output subsidy and mitigates electricity price increases, but it raises economic cost. The way electricity prices are determined in practice departs from economic efficiency, and the output subsidy amplifies the distortion away from efficiency in most electricity markets and time blocks. In contrast, the auction approach increases electricity prices the most, but the efficiency cost of the price changes is less than under the other approaches.

Significant distributional differences exist among the approaches to allocating emission allowances. Consumers face the highest electricity price but they face the lowest natural gas price under the auction approach. Grandfathering falls mid-point between the other two approaches with respect to both electricity and natural gas price changes. The generation performance standard leads to the lowest electricity price and consumers are best off under the generation performance standard when examining just electricity price changes. However, this approach also yields the highest natural gas price.

The auction approach is unique because it raises substantial revenues that, when taken into account, make it preferable for consumers on distributional grounds. How auction revenues are used is important to the societal cost of the auction. Several recent studies argue that an auction or emissions tax can be substantially less costly than other approaches to allocating allowances because auction revenues can be used to reduce the labor income tax or other taxes. We assume revenues are used in the least efficient way that is discussed in the economics literature, which is direct redistribution to households instead of using revenues to reduce pre-existing taxes. Nonetheless we chose to model direct redistribution to households because, even under this approach, the auction is roughly one-half the cost of the other approaches. If auction

revenues are used in a more efficient way, the cost-effectiveness of this approach would increase substantially.

Producers can expect to do the best under grandfathering because it represents a substantial transfer of wealth to producers from consumers. In fact, producer profits and asset values increase substantially compared to the baseline (absent a carbon policy), making producers better off with a carbon policy than without, but leaving consumers substantially worse off. Even though grandfathering appeared to be the intermediate approach with respect to its effect on electricity and natural gas prices, it is the most extreme approach with respect to transfers of wealth. The auction and generation performance standard approaches have much more moderate distributional effects and therefore we focus more attention on a comparison of these two alternatives.

Producers can expect to do at least as well in aggregate under an auction, compared to a generation performance standard, while owners of existing assets can expect to do substantially better under an auction. This finding raises an interesting paradox that producers do better paying for emission allowances (through the auction) than receiving them for free (under the generation performance standard approach). The reason for this is the generation performance standard yields the lowest electricity price, which erodes the value of existing assets. The auction yields the highest electricity price, which preserves or enhances the value of many assets.

Although consumer expenditures increase under the auction approach, substantial revenues also are raised and they serve as compensation to consumers. A portion of revenues could be diverted to compensate producers as well, perhaps through a hybrid program that combined an auction with a generation performance standard during a transition period, culminating in an auction of all allowances in future years. In addition, a portion of revenues under an auction, or direct allocation of some allowances, could be directed to support energy conservation and other benefit programs.

Finally, the auction approach also has institutional features that make it more readily expandable to an economywide approach to regulating carbon emissions, which most economists prefer to an approach focused just on one sector. The focus here on the electricity sector only is of relevance nonetheless, even in the context of an economywide carbon policy. Although the electricity sector is responsible for just over one-third of carbon emissions in the US, it would be expected to contribute two-thirds to three-quarters of the emission reductions under a policy that encompassed the entire economy in a cost-effective way.

The bottom line is that the auction approach weighs in at substantially less economic cost to society than either of the two gratis approaches to allocating allowances. The auction approach also provides policymakers with flexibility through the collection of revenues that can be used to meet distributional goals or to enhance the efficiency of the process even further by reducing pre-existing taxes. Because the auction approach is so cost-effective, a corresponding carbon policy will have less effect on economic growth than under the other two approaches. This attribute provides perhaps the most significant form of distributional benefit.

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1. Introduction

In March 2001 President Bush announced that the United States would not participate in an international agreement to reduce greenhouse gases that conforms to the 1997 Kyoto Protocol guidelines. The announcement ignited a controversy about the form of future climate policy. The preponderance of emerging scientific evidence suggests that emissions of greenhouse gases are leading to warming of the planet (IPCC, 2001). Eventually the United States will have to address the issue of carbon emissions, and the Bush administration has repeatedly acknowledged the severity of the problem. President Bush has ordered a Cabinet-level review of U.S. climate change policy and spoken about the need for market-based approaches to reducing emissions. It remains possible that in designing a carbon policy the president will follow in the footsteps of his father, who initiated the sulfur dioxide (SO_2) emission allowance trading program as part of the 1990 Clean Air Act Amendments.

One of the biggest issues in designing a market-based carbon policy is how to initially allocate the emission allowances. The economics literature typically has recognized allowance allocation primarily as a distributional issue, or simply not recognized it as an issue at all. Coase (1960) demonstrated that as long as property rights are well established and other important conditions are satisfied, the initial allocation of permits would not matter to the attainment of an efficient outcome. However, Coase went further to acknowledge that when individual behavior could affect the magnitude of external cost, then the allocation of property rights could affect efficiency because it influences an individual's incentive to exercise due care to minimize the external cost (Mohring and Boyd, 1971; Shibata and Winrich, 1983). Furthermore, Coase emphasized the importance of the "other conditions" that are unlikely to be satisfied when pre-

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existing distortions away from efficiency characterize the economy (Coase, 1992). In these cases, Coase argued, the design of institutions matter to the efficiency of implementing a policy.

The recent literature on allocating emission allowances has illustrated the efficiency consequences of various schemes that result from interactions with pre-existing distortions away from economic efficiency (Bovenberg and de Mooij, 1994; Parry, 1995; Bovenberg and Goulder, 1996; Goulder et al. 1999). The most apparent of the preexisting distortions are taxes, which cause a divergence between the opportunity cost of goods and services and consumers' willingness to pay. When layered on top of preexisting distortions, the additional cost of regulation can be magnified in the general economy. The magnitude of the "tax interaction effect" is potentially very significant. For example, Parry, Williams, and Goulder (1998) estimate that reducing carbon emissions through grandfathered and tradable carbon permits for the entire economy will be efficiency-reducing unless the marginal benefits from carbon abatement exceed $18 per ton. The allocation of emission allowances matters because of its effect on product prices and because of the potential use of revenues (from taxes or allowance auctions) to decrease preexisting distortions, for example by reducing pre-existing taxes, thereby providing an important remedy. Parry, Williams, and Goulder find an emission tax (or revenue-raising auction) can be efficiency-enhancing at any level of marginal benefits from carbon abatement.

In this paper, we look at a substantially simpler problem, but one that has at least as large an impact on social welfare. The problem is simpler because we focus on the electricity sector, use partial equilibrium analysis, and do not reference the tax-interaction effect. We reason that an extension to general equilibrium analysis and inclusion of the tax-interaction effect would only strengthen the results, but to do so with current modeling technology would require a simplification of the institutional features incorporated in the model that provide the results of interest. The features that are relevant include the characterization of technologies and costs for electricity generation, and the characterization of institutions for determination of electricity price.

Our primary questions are (1) how the method of allocating carbon emission allowances to the electricity sector matters to the efficiency of compliance in achieving an environmental target, and (2) how it matters to the distributional outcome. One method we model is a revenue-raising government "auction," which may be capped by a maximum price for allowances. We also model two policies in which government allocates allowances to industry for free. The first, labeled "grandfathering," distributes allowances to electricity generators on the basis of historic generation. This approach is embodied in the SO_2 emission allowance trading program initiated under the 1990 Clean Air Act Amendments. The second is labeled a "generation performance standard." Under this policy, emission allowance allocations are updated on the basis of current or recent year generation. This approach is embodied in policy in Sweden for taxation of nitrogen oxide (NO_x) emissions, with revenues returned to industry on the basis of generation. It is also embodied in several current legislative and regulatory proposals in the United States.

In brief, the choice of institution for allocating allowances matters tremendously for efficiency. We find that the auction accounts for roughly one-half the cost of either of the free allocation approaches, from a societal perspective. Important costs are incurred outside the electricity sector due to changes in fuel prices in response to fuel demand, and these costs reinforce the main finding. Significant distributional differences exist among the approaches, according to our findings. Electricity consumers lose the most surplus under the auction but they receive most of it back if revenues are redistributed in some fashion. Grandfathering leads to significant gains in producer surplus due to the transfer of wealth implicit in the allowance allocation. The generation performance standard is the worst mechanism from the perspective of producers because it does the most to erode the value of existing assets.

2. Motivation

There are two main reasons why allocation matters to the cost of reducing carbon emissions, and both stem from the effect of each method for allocating emission allowances on the determination of electricity price. The first reason has to do with the special nature of the generation portfolio standard. This approach actually combines two policies. One is a cap and trade program to regulate emissions, and the second is a subsidy for electricity generation embodied in the allocation of allowances. The subsidy for generation results because a firm or facility earns a greater share of the asset value of the emission allowances when it increases its share of total generation (Fischer, 2001). For example, imagine the variable cost of electricity generation is $40 per megawatt-hour (MWh) (4 cents per kilowatt-hour (kWh)) and the marginal generating facility has a below average emission rate. Assume each MWh of generation from that generating facility earns a share of emission allowances worth $2 per MWh – then the opportunity cost of generation is actually $38 per MWh. Consequently, the generation portfolio standard provides incentives that will tend to increase electricity generation and reduce electricity price, compared to a scheme that does not allocate allowances on the basis of electricity generation. Increased generation means that greater reductions in emission rates must be achieved at all generating facilities to achieve the emission target for the sector.

The second reason that allocation matters to the cost of reducing carbon emissions has to do with inefficient pricing of electricity. Roughly half the nation has committed to competitive pricing of electricity by a date certain (however, a considerable dose of regulation remains even in the observed prices in these states). The other half remains committed to regulated pricing that explicitly balances efficiency and equity goals. As a consequence, the marginal cost of electricity supply differs from the marginal willingness to pay of consumers. How allowances are allocated will affect electricity price, potentially amplifying the difference between marginal cost and willingness to pay. Further, the inefficient pricing of electricity may serve to amplify the effect on efficiency of the output subsidy under the generation performance standard in particular.

We model the three approaches for allocating emission allowances that have credibility in the current debate on controlling carbon emissions. First, the SO_2 emission allowance trading program created by Title IV of the 1990 Clean Air Act Amendments has been widely cited as a successful example of an economic approach to environmental regulation (Carlson et al., 2000; Stavins 1998). The amount of emission allowances that are distributed under a specified aggregate cap is roughly half of baseline projections for emissions from the electricity industry as estimated over 10 years ago, when the legislation was designed. Emission allowances are allocated without charge through a variety of rules and special provisions. However, the underlying principle that characterizes the vast majority of allocations is a gratis allocation based on heat input and roughly proportional to historic emissions, the grandfathering approach (Joskow and Schmalensee, 1998).

A second method of allocating allowances is known alternatively as output-based allocation or a generation performance standard though there are some important differences. The output-based approach would allocate a fixed quantity of emission allowances to sources in proportion to their relative share of total electricity generation in a recent year. This proportion would be updated as the generation mix changes over time. The generation performance standard uses electricity generation projections over a specific year and a target quantity of emissions to calculate a targeted average emission rate, and sources are then allocated emission allowances according to this emission rate. Hence, there are two differences between the approaches. One difference is that since the output based allocation is calculated on the basis of generation in a recent year, discounting over the time lag between the recent year and the current year will lessen the magnitude of the incentive to expand generation to earn additional allowances, an incentive we discuss at length later. Second, since the generation performance standard is calculated on the basis of projected generation, total emissions can exceed or fall short of the emission cap target if generation exceeds or falls short of the projected level.

An analogous approach was pioneered in practice in Sweden in the form of a tax on emissions of NO_x from electricity generators that was adopted in 1990 and implemented in 1992 (Hoglund, 2000; Sterner and Hoglund, 2000). The revenues from the tax are refunded to the industry on the basis of electricity generation. The approach has been described as "earmarking" of revenues by Fischer (2001).

In the United States the output-based approach has been included in the Environmental Protection Agency's proposals for allocating NO_x emission permits as part of the regional NO_x trading program known as the NO_x SIP (State Implementation Plan) Call. That program, scheduled to take effect in 2004, would impose a cap-and-trade program on electricity sector emissions in 19 eastern states and the District of Columbia. The generation performance standard is specified (Allen, HR 1335) or suggested (Waxman, HR1256; Jeffords, S556) in legislative proposals before the 107th Congress and in bills in the previous Congress aimed at capping emissions of carbon, NO_x and mercury and achieving further reductions in SO_2 from the electricity sector.

We label the approach we use as the generation performance standard. In our model the allocation of emission allowances is determined simultaneously with the quantity of generation in the current simulation year. Both the allocation and generation are calculated within an iterative convergence process so the emission cap under the generation performance standard is achieved almost exactly.

The third method of allocating emission allowances is a revenue-raising auction. In a world absent uncertainty, with competitive markets, this would be equivalent to a tax set at a level that would achieve a level of emissions equal to the number that are auctioned. In the face of uncertainty, the question of the choice of a quantity instrument (tradable emission allowances) versus a price instrument (emission tax) (Weitzman, 1974) has been re-examined by Pizer (2001) in the specific context of greenhouse gases. Pizer finds that an optimal emission tax policy generates gains that are five times higher than the optimal tradable emission allowance policy. From this, Pizer explores the possibility of a hybrid policy (Roberts and Spence, 1976) that combines an initial distribution of tradable emission allowances with a safety valve that limits the maximum price of an allowance. At the safety valve price, the government issues an unlimited number of additional allowances. The safety valve approach leads to welfare benefits slightly higher than a tax policy, while it preserves the flexibility to distribute emission rights based on equity and or political considerations. Recently, this approach also has attained visibility in debates about federal policy for reducing carbon emissions.[1]

The method of allocation has been important to the previous political debate about emission-trading programs, but the magnitude of the asset value of permits is small compared to the asset value of carbon permits. For example, the "grand experiment" of SO_2 trading created an intangible property right with a total asset value of about $2.7 billion in 2010. EPA's proposed regional trading program for nitrogen oxides from electricity generation that is expected to take effect in 2004 would create assets with a total value of about $1.7 billion per year. In contrast, full compliance with the Kyoto Protocol – through nationwide carbon-trading to achieve more than a 30% reduction in carbon emissions – would create an asset with an annual value of about $450 billion in 2010 (1997 dollars) (US EIA, 1998). The moderate policies we consider in our detailed simulation results would achieve a 6% reduction in emissions from within the electricity sector only, but still would create assets with a total value in the range of $14.8-$23.6 billion per year, depending on the approach that is used and the allowance price that results.

We consider a carbon emission target for just in the electricity sector, which is relevant for several reasons. First, electricity is the most important individual sector to examine. It is currently the source of about one-third of carbon emissions in the economy, but to achieve full compliance with the Kyoto Protocol in a cost-effective manner would require the electricity sector to provide between 68% and 75% of total emission reductions in the U.S. economy (US EIA, 1998). Second, a number of proposed legislative initiatives over the last few years (including those previously listed) would target just the electricity sector. In some cases the electricity sector is identified explicitly as a first step to an economywide approach.

Third, a qualitative criterion to be considered is how each of the proposed approaches to allocating emission allowances could be applied or expanded to an economywide approach in the future. A study by the U.S. Congressional Budget Office provides a qualitative evaluation of different allocation approaches and considers allocation "downstream" at the sector or end-use level where most carbon emissions are actually released to the environment, or "upstream" at the mine-mouth or wellhead, where potential carbon emissions are embodied in fuel (U.S. CBO, 2001). The study does not reach specific conclusions, but suggests that an upstream approach would be preferable according to several criteria, including administrative simplicity and

[1] "Innovative Plan to Regulate Carbon in Fuel gains Momentum," *Inside EPA,* March 9, 2001

consistent pricing of emissions throughout the economy, which would help achieve allocational efficiency.

Under the auction of emission allowances that we model, the costs incurred within the electricity sector are a direct subset of costs that would be born by the sector if an auction approach were used for the entire economy and the electricity sector were to achieve the emission target we specify. For the other two gratis approaches to allocating allowances that we model – grandfathering and the generation performance standard – the analogue between a policy in the electricity sector and one for the entire economy is difficult to imagine; it also would be challenging to achieve a consistent approach throughout the economy. The question of how the two gratis approaches could be expanded beyond the electricity sector also is not easy to answer. The qualitative consideration about the practicality and expandability of the institutions that would be created under each allocation scheme is an important one that we revisit in our concluding discussion.

Two other recent studies have looked at the cost-effectiveness of various approaches to allocating emission allowances in the electricity sector within quantitative analyses but none have compared gratis allocation schemes with an auction. Beamon, Leckey, and Martin (2001) compare a grandfather policy and a generation performance standard policy using the National Energy Modeling System (NEMS) simulation model. The study finds both approaches lead to a substitution of natural gas for coal-fired generation, with a very modest contribution to electricity generation from renewables. However, a generation performance standard leads to lower electricity prices, higher natural gas and carbon allowance prices, and greater total resource costs.

The grandfather policy modeled by Beamon et al. is a mix of the cases we study because they assume that the opportunity cost (market price) of emission allowances used by the marginal electricity generating unit are fully reflected in electricity prices even in regions where electricity is priced according to cost of service. However, in regulated regions of the country, regulators establish electricity prices on the basis of the cost of service and tend to assign a cost of zero to emission allowances that a utility obtains free-of-charge under grandfathering or a generation performance standard. Beamon et al. justify their approach with the observation that the electricity wholesale market is expected to become increasingly competitive and so the cost of purchasing allowances is included in operating costs. In our analysis, this assumption is analogous to the sensitivity case in which we assume nationwide restructuring and pervasive competitive pricing of generation in the electricity industry. Nationwide restructuring is one possible future for the electricity industry but it is not yet reflected in policy.

A second feature of the Beamon et al. analysis is that under the generation performance standard they describe, allowances are allocated to all electricity generators including hydro and nuclear generators, which do not emit carbon. This allocation rule differs from the generation performance standard embodied in most of the proposed legislation, which would allocate allowances only to carbon-emitting units. We compare these two alternative approaches to a generation performance standard in sensitivity analysis and show the difference in which facilities are included in the allocation has an important effect on the results.

Another analysis has considered the generation performance standard allocation mechanism in the context of regional policies to reduce NO_x emissions. ICF Consulting (1999) compared the generation performance standard with a grandfather mechanism and found the generation performance standard yields somewhat higher program costs and less leakage to outside the region/sector covered by the program due to the subsidy to increased electricity generation (Fischer, 2001). The study also found the generation performance standard approach for NO_x allowances would have little effect on the fuel choice for electricity generation. One difference between the ICF study and this one is that the value of carbon allowances are one or more orders of magnitude greater, as has been mentioned. Also, the ICF study examined only nationwide restructuring, which is one case in our sensitivity analysis.

3. Assumptions, Scenarios, and Sensitivities

In this section we describe common assumptions regarding economic and environmental regulations in the electricity sector and each of the allocation mechanisms. We then provide a brief description of the Haiku Electricity Market Model that we use for most of our analysis.[2] We conclude this section with a brief discussion of the alternative assumptions regarding economic regulation that are examined in the sensitivity analysis presented later in the paper.

3.1 Maintained Assumptions

The effect of a carbon allocation mechanism on electricity prices, production costs, and electricity sector profits depends crucially on how the electricity sector is regulated. Regulatory regimes facing electricity generators vary by region across the country. In our central case,

[2] The Haiku model was developed to contribute to integrated assessment with support from EPA, the U.S. Department of Energy, and Resources for the Future.

“limited restructuring,” we assume that marginal-cost pricing of electricity is implemented in those regions and subregions of the North American Electric Reliability Council (NERC) where most of the population resides in states that have made a commitment to implement electricity restructuring by a date certain. The schedule for transition from cost-of-service to competitive (marginal cost) pricing for generation in these regions is reported in Table 1. In the limited restructuring scenario, no other regions adopt competitive pricing for generation over the course of the forecast period, which extends to 2020. All other regions are assumed to have regulated prices for generation set equal to the average cost of service. Transmission and distribution services are priced at the average cost of service in all regions, although the rates for these services differ across regions. Industrial customers pay less for transmission and distribution services.

In all competitive regions, utilities recover 90% of the cost of assets that are “stranded” in the transition from cost of service to competitive pricing. Stranded costs are those investments that will be unable to recover undepreciated book value after the transition. Stranded cost recovery is a charge per kWh that is imposed on all sales, in the same way that distribution system charges are imposed. All regions that have implemented the transition have provided for stranded cost recovery, and this is represented in our model. Second, we assume that the use of time-varying prices of electricity will become more widespread as a result of restructuring. We represent this assumption by assuming industrial customers face time-of-use pricing in any region that has implemented competitive pricing.[3] For all other customer classes in all regions, the retail price is assumed not to vary between peak and off-peak times, but it can vary across seasons.

Another way that prices differ between marginal and average cost regions is the pricing of reserve generation services. In all regions, after energy demand is satisfied, remaining generation capability is ordered according to the going-forward fixed cost (per MW). The going-forward fixed cost includes all capital costs except those for capacity already existing in 1997, fixed operation and maintenance expenses, general and administrative costs, and tax costs. The supply schedule for reserve services is based on the going-forward fixed cost. Reserve requirements are determined as a function of total demand in each region, and the required level

[3] These time-varying prices are analogous to real-time prices in that they reflect the balance between supply and demand during the actual time block for which price is being set and are not specified in advance as are some time-of-day (or time-of-use) rates.

of reserves varies by region.[4] The required reserves are met by working up the reserve supply schedule.

What differs between average- and marginal-cost regions is the way in which the cost of reserve services is reflected in price. In average-cost regions, the fixed costs of the units providing reserve services are added to total cost of service and are automatically recovered in price.[5]

In marginal-cost regions, an equilibrium marginal price for reserve services is determined through an iterative convergence process that will entice services sufficient to meet the reserve requirement. If inadequate reserve services are offered in a particular region and time block, the reserve price in that time block is increased and the model is solved again. In addition, an incentive compatibility constraint requires that, in addition to those units providing reserve services, generating units also receive the marginal reserve price. This constraint guarantees that units have no incentive to switch between generation and reserve services as long as there is no collusion.

Investment and dispatch decisions within the electricity sector also clearly depend on the environmental regulations governing the sector. We assume that there are no changes in the regulation of SO_2 emissions beyond those established under the 1990 Clean Air Act Amendments and no restrictions on mercury emissions. NO_x emissions are governed by a regional cap and trade program for summertime emissions in the eastern states represented by the regions in the Haiku model that are approximately equal to the SIP region.[6] The included regions are identified in the last column of Table 1. The summer (five-month) emissions cap under this

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[4] Reserve services are differentiated to the extent that steam generators are limited to provide only 50% of total reserves.

[5] For the purpose of inter-regional power trading, we calculate a willingness-to-pay in average cost regions by taking the fixed cost (per MW) of the marginal reserve unit and apportioning it across all time blocks in which that unit provides generation or reserve services. This approach yields quite comparable marginal reserve prices as in marginal cost regions, reflecting the marginal scarcity value of reserve services for a given level of generation capacity and electricity demand.

[6] These regions include NE, MAAC, NY, STV, ECAR, and MAIN (see Table 1 for geographic descriptions) but they exclude a small portion of western Missouri, which is one of the 19 states. Small parts of Illinois and Wisconsin are also excluded. These regions include the eastern half of Mississippi, Vermont, New Hampshire, and Maine, which are not part of the region identified by EPA. However, the other New England states—Connecticut, Massachusetts, and Rhode Island—are part of the eastern region covered by the ozone transport region. The reconciliation of these two programs may ultimately involve their participation. For more information on the recent history of the regulation of NO_x emissions from the electric power sector, see Burtraw et al. (2001).

program is based on an average emission rate for NO_x of about 0.15 pounds per million Btu (mmBtu) of heat input at fossil fuel–fired boilers. The emissions cap is 444,300 tons per summer season within the SIP region, compared with an emissions level of 1.529 million tons in 2012.[7] We assume the policy is announced in 2001 and implemented in 2004.

The focus of this research is regulation of CO_2 emissions, which we measure in equivalent metric tons of carbon. We establish a quantity cap on carbon emissions and, in all scenarios, electricity generators are allowed to trade carbon emission allowances to achieve the least cost allocation of emission reductions across electricity generators. The method for allocating emission allowances at the outset varies across the different scenarios and is our primary interest.

3.2 Carbon Emission Target and Allocation Scenarios

We explore a wide range of carbon emission targets to establish the generality of our results. Subsequently we examine a specific and relatively modest target in detail. That target is 35 million metric tons of carbon reduction from emissions that are achieved in a baseline absent any carbon policy. This shift constitutes a 6% reduction from baseline and yields total emissions of 591 million metric tons of carbon (mtC). The target is phased in along a linear schedule and fully implemented in 2008. There is no banking of allowances. Most of the numerical results are for the year 2012, when transition issues would be resolved.

Three approaches to allocating carbon emission allowances are explored. Under the auction (AU), emission allowances are sold by the government to electricity generators. When the aggregate emission cap is set at 591 million mtC, the equilibrium market price of an allowance is $25 per mtC in 2012. A second approach to allocating allowances is grandfathering (GF). In this case allowances are allocated free of charge to existing fossil-fuel fired generators based on their total generation in 1997. Each oil-, gas-, or coal-fired generator receives a share of the total annual carbon cap equal to its share of total fossil-fired generation in 1997, and the equilibrium market price of an allowance is $38 per mtC. A third approach to allocating allowances is the generation performance standard (GPS), in which allowances are allocated free of charge to all electricity generators excluding nuclear and hydro-power facilities based on

[7] This emission cap was determined by applying the emissions rate of 0.15 lb per MMBtu to fossil fuel-fired generation in the baseline for 1997, which is the same methodology applied by EPA.

electricity generation in the current year. As new generators enter, they are entitled to a share of the total allowances that they can either use to cover their own emissions or sell at the going market price. If existing generators increase their share of total generation, they increase their share of allowances. The equilibrium market price for an allowance under GPS is $40 per mtC.

3.3 Sensitivity Analysis

After analyzing the scenarios described above, we perform several sensitivity analyses to examine the effects of our assumptions about economic regulation and competition in the electricity sector, as well as an alternative form of the GPS. We also conduct detailed analysis of a 75 million mtC reduction target to see if specific findings about how compliance is achieved are sensitive to the level of the reduction.

We label an alternative to limited restructuring as "nationwide restructuring." Under this scenario, we assume that restructuring is implemented across the country by 2008. As shown in the nationwide restructuring column in Table 1, three additional regions are assumed to implement restructuring in 2004 and the remaining five regions do so by 2008. There are several parameters in the model that take on different values in the nationwide restructuring scenario than under our standard assumptions of limited restructuring (Table 2). They fall into three categories: productivity change, transmission capability, and renewables policy.

Productivity change is implemented in the model through changes in four parameters: improvements in the maximum capacity factor at existing generators, reductions in the heat rate at existing coal-fired generators, reductions in operating costs, and reductions in general and administrative costs at all existing generators. The rate of change in these four parameters is a function of the proportion of the country that has committed to marginal cost pricing. A single value applies to the entire country, reflecting the common availability of technology and the common investment climate shared by firms in different regions, as well as the expectation that marginal cost pricing and competition could spread to all regions in the future. As the number of regions committing to marginal cost pricing grows, the rate of improvement in these four parameters grows.[8] Table 2 is a summary of the ratios of the values in 2008 to the values in 1997 (the year of our data) for each of these variables under the two economic restructuring scenarios.

We also include different assumptions about transmission capability and renewables policy. In the baseline absent any carbon policy, we assume that inter-regional transmission capability does not grow over time. In the nationwide restructuring scenario, we assume that by 2008 transmission capability is 10% higher than in the baseline scenario. Also, we assume that a renewable portfolio standard (RPS) is implemented in 2008 in the nationwide restructuring case, which mirrors recent proposals by setting a goal for penetration of renewables while setting a cap on the subsidy that can be earned by renewables. The cap is set at $17 per megawatt-hour, slightly inflated from the $15 cap included in the Clinton administration proposal. In every example we describe, the subsidy cap is binding, yielding renewables-based electricity generation of less than 3.5% of total generation. The nonhydroelectric renewables-based technologies that qualify for the RPS in our model are wind, solar, dedicated biomass, municipal solid waste, and geothermal.[9]

In another sensitivity case, we assume that all regions of the country price electricity at average cost. Under this scenario, electricity prices charged to consumers can vary by season. Productivity growth is assumed to continue at historic rates. Inter-regional transmission capability is fixed at current levels and there is no RPS.

As an alternative to the GPS in our central case, we also consider a sensitivity analysis that allocates emission allowances to all generators including nuclear and hydro. We also consider the benefits, where possible, of identifying cost-effective ways to reduce demand in order to help meet emission goals, using a portion of allowances allocated through the GPS as an incentive or as compensation for doing so.

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[8] Specifically, the rate of change in the three productivity change parameters is a weighted sum. The sum is the proportion of megawatt hours sold in marginal cost pricing regions times an optimistic rate of change, plus the proportion of megawatt hours sold in average cost pricing regions times the historical rate of change (under average cost pricing) in each parameter. The weights are constructed using electricity sales data from 2000, prior to the implementation of restructuring in most states.

[9] We assume that any electricity generated by co-firing a coal-fired generator with a minimal percentage of biomass fuel would not be allowed to be counted against an RPS.

4. Models

The Haiku electricity market model calculates equilibria in regional electricity markets with interregional electricity trade.[10] The model includes integrated algorithms for investment and retirement of generation capacity, selection of NO_x emissions control technology, and SO_2 compliance. The model simulates electricity demand, electricity prices, the composition of electricity supply, and emissions of major pollutants, including NO_x, SO_2, mercury, and carbon. Generator dispatch in the model is based on minimization of short-run variable costs of generation. Adjustments to capacity are based on net revenues accounting for all going-forward costs including new capital investments.

Two important components of the Haiku model are the intraregional electricity market component and the interregional power trading component. The intraregional electricity market component solves for a market equilibrium identified by the intersection of price-sensitive electricity demand for three customer classes (residential, industrial, and commercial) and supply curves for four time periods (peak, shoulder, middle, and base load hours) in three seasons (summer, winter, and spring-fall) within the 13 NERC regions and subregions.[11] Parameters for each regional supply curve are established using cost estimates and capacity information for up to 45 aggregate "model plants" defined by technology, fuel, and vintage. The interregional power trading component solves for the level of interregional power trading necessary to achieve equilibrium in regional electricity prices (gross of transmission costs and power losses). These interregional transactions are constrained by the assumed level of available interregional transmission capability as reported by NERC.

We provide an analysis of the impact on other sectors of the economy by linking results from the Haiku model with an Industrial Sector Model (INSECT) developed by Resources for the Future. INSECT, which is based on the Energy Information Administration's National Energy Modeling System model of energy demand in the industrial sector, distinguishes 15 industry groups, for which it forecasts the demand for 13 main fuels in 4 geographic regions. The model generates the quantity consumed of each fuel along with industrial sector electricity

[10] The Haiku model has been evaluated under comparable assumptions and policy scenarios in comparison with the EIA's National Energy Modeling System, the DOE's Policy Office Electricity Model, and other participants of the Stanford Energy Modeling Forum (Energy Modeling Forum 2001, 1998).

[11] The electricity demand functions include customer class specific elasticities of demand that vary by season and to a lesser degree by time block.

generation and corresponding steam production. While the model does allow for shifts in the geographic location of production in response to relative fuel costs, it does not allow for changes in total production. The model also calculates carbon emissions in the industrial sector based on the carbon contents of the fuels used.

5. Results

In this section we report our main results under the assumption of limited restructuring in the electricity sector. Subsequently, we present sensitivity analysis, including the case of nationwide restructuring.

5.1 Comparison of policies over range of emission targets

The main finding from our research is that allocation through the AU approach is roughly one-half the cost to society of allocation through GF or GPS when viewed over a range of emission targets. This finding is illustrated in Figure 1 in a snapshot for the year 2012. The horizontal axis indicates reductions from the baseline emissions absent any carbon policy in 2012, which are estimated to be 626 million mtC. The vertical dotted line anchors a point equivalent to 1990 emissions in the electricity sector, which were about 150 million mtC less than in the baseline for 2012. The vertical axis reports the average social cost in 1997 dollars per mtC of emission reduction.

Average social cost is calculated as the ratio of economic cost divided by tons of emission reduction. Economic cost is measured as the sum of the changes in consumer and producer surplus in the electricity sector. Consumer surplus is the difference between consumers' willingness to pay for electricity and the price consumers actually pay. We measure this as the area under the Marshalian demand curve and above electricity price. Producer surplus is the difference between revenues and costs, or equivalently producer profits. A critical issue, as we will see below, is how revenues collected under the AU are used. In the results illustrated in Figure 1, we assume revenues are redistributed to households.

For more moderate emission reduction targets, the ratio of cost under the AU approach is closer to one-third the cost of GF and GPS, and it is somewhat greater than one-half for more ambitious reduction targets. However, the comparison of social cost and the relative cost-effectiveness of AU is of increasing importance under the more ambitious targets because the overall level of costs incurred and the absolute value of the cost savings under AU grow substantially.

Figure 2 provides a partial explanation for why social cost differs among the allocation methods by illustrating the price of an emission allowance commensurate with achieving various specified quantity targets for emission reductions from the 2012 baseline. Over the range of emission targets we examine, AU generates the most emission reductions for a given allowance price. Although GF and GPS achieve comparable reductions at lower permit prices (i.e., less than $60 per mtC), GF results in more reductions at higher permit prices.

5.2 How reductions are achieved

To examine how emission reductions are achieved, we focus on a relatively moderate policy that reduces carbon emissions by 35 million mtC or 6% from the 2012 baseline. The reductions are reached with a permit price of $25 under the AU, $38 under GF, and $40 under GPS.

Carbon reductions in the electricity sector can be achieved in two ways. One is by reducing consumption (or generation). As shown by Table 3, the annual national electricity generation falls by 1.8% (77 billion kWh) under the AU approach, 1.0% under GF, and less than 0.4% under GPS. Changes in output follow directly from changes in electricity price, which is discussed below.

The second and more important way in which carbon reductions are achieved is through switching to fuels with a lower carbon content (for example, switching from coal to natural gas). The decrease in coal-fired generation is relatively similar under the three policies. Under the AU approach, coal-fired generation decreases by about 8.5% (152 billion kWh), while it decreases by about 9.2% under GF, and 10.2% under GPS. The difference among the approaches is much greater in the effect on gas-fired generation. Generation with natural gas increases by nearly 4.5% (63 billion kWh) under AU, and by nearly 7.4% under GF. However, it increases by 11.1% under GPS, or 2.5 times the increase under AU. The decrease in coal-fired generation is almost entirely made up by an increase in gas-fired generation under GPS, indicating that the adoption of lower carbon content fuels is most accelerated under GPS.

Generation from non-hydro renewable sources, for example wind, in the baseline is 30 billion kWh or about 1.7% that of coal. Wind generation increases under all three allocation approaches with the maximum increase of 33% coming under GF and a modest increase of 20% under both AU and GPS. The increase in wind generation is constrained primarily by the interaction of new capacity on electricity price and the degree to which new wind investments are profitable.

Changes in the installed generation capacity are less in relative terms than changes in generation. One reason is that existing capacity can shift from providing generation to providing reserve services. Coal-fired capacity falls under every approach, but very slightly. Natural gas-fired capacity falls slightly under AU but increases under GF and GPS. Perhaps surprisingly, the increase is the greatest under GF because combustion turbines, which typically provide intermediate-to-peaking generation services, play a larger role in generation. The increase in combustion turbines follows from the time profile of changes in demand. Under GPS, the least reduction in total generation occurs in the base time period and the greatest reduction occurs in the peak period. Under GF the reduction in generation is spread more evenly relative to other policies. For example, in the MAIN subregion (Illinois and Wisconsin), the reduction in generation in the intermediate time period (about 20% of the hours in a day) under GPS is greater than under GF by about 6.6 million MWh.

5.3 Changes in price and expenditures

Since change in electricity price plays the critical role in determining the changes in consumption and in the calculation of consumer surplus and producer surplus it is useful to examine how electricity prices are determined. Table 4 provides a brief summary. Total cost is the sum of capital, fixed operation and maintenance (O&M), fuel and variable O&M under all three approaches. In addition, total cost is affected by what a firm pays to obtain emission allowances. By ignoring allowances acquired through trading among firms and focusing only on the original allocation, total cost is affected only under the AU, as indicated in Table 4.

In regulated regions, we assume regulators provide an incentive or otherwise require firms to utilize their facilities in order to minimize costs according to the ordering of variable costs of generation. In competitive regions, we assume the market provides the discipline to insure facilities are used according to the ordering of variable costs. Variable cost under the three approaches is the sum of fuel, variable O&M, and allowances used for compliance. Allowances are expected to affect the variable-cost ordering of generation capacity since there is an opportunity cost to using allowances that is equivalent to their market value. In addition, under the GPS there is a rebate to firms in the form of the allowance allocation per unit of electricity generation. Since the rebate is uniform for each unit of generation, it reduces the variable cost of every kWh produced by all facilities except nuclear and hydro. Since nuclear and hydro have very low variable costs, they appear early in the variable cost ordering and are utilized to equal degree with or without the GPS allocation. Hence, the GPS does not alter the utilization of units.

Finally, Table 4 indicates how the price of generation services is determined. (This price is independent of cost of transmission and distribution service. Also, it ignores important details about calculating reserve capacity costs, the role of time-of-day pricing, stranded cost recovery, etc.) Under the limited restructuring scenario, about half of the nation has regulated electricity prices set to equal average cost-of-service. In regulated regions the price of generation services is determined by average cost per unit of generation. Since total cost is greatest under AU, then electricity price would be greatest under AU. Other things equal, the price under GF and GPS would be the same.

In competitive regions, electricity price is determined by the variable cost of the marginal generation facility. In this case, the price under AU and GF would be the same. However, the price of GPS would be less because of the rebate or output subsidy associated with the allocation of allowances.

In the political debate, the two variables that will attract the most attention are the expected increases in both electricity and natural gas prices. Figure 3 illustrates these changes simultaneously and Table 3 reports the data for the numerical example of a 35 million mtC reduction under the three approaches. The AU approach results in the largest increase in electricity price of 6.1% ($3.7/MWh) from the baseline level of $61/MWh (6.1 cents/kWh). GF is intermediate with a 3.3% increase in electricity price, and GPS yields the smallest increase of 0.7% in electricity price.

The increase in natural gas price occurs in response to changes in the demand for fuels for electricity generation. The ordering of the magnitude of the change is the converse of that for electricity price. The least increase in natural gas price is 3.2% ($0.12/mmBtu) under AU. Gas price increases by 5.5% under GF, and by 6% under GPS. Finally, there is a slight decrease in the national average delivered cost of coal in the electricity sector, a result of the decreased use of coal in electricity generation.

The changes in price and commensurate change in consumption lead to noticeable changes in expenditures. The AU approach yields an increase of $10.6 billion in expenditures on electricity from a baseline level of $243.4 billion. GF yields an increase of $6.0 billion, and GPS yields an increase of $1.1 billion.

To illustrate the potential importance of fuel price changes, consider the change in expenditures for natural gas consumption outside the electricity sector. These expenditures are expected to total 19.56 billion mmBtu in 2012, according the Energy Information Administration (US EIA 2000). Were there no response in demand due to changes in price, the AU approach would impose additional expenditures of $2.3 billion for natural gas outside the electricity sector, GF would impose additional expenditures of $3.9 billion, and GPS would impose changes of $4.3 billion.

However, one would expect demand response to changes in price, which could be accomplished through conservation or through substitution to other fuels. To estimate such changes for the residential sector, we use a long-run demand elasticity estimate of –0.67 from Dahl (1993).[12] Incorporating demand response in this way leads to a $220 million dollar increase in residential expenditures on gas under the AU approach, a $320 million dollar increase in gas expenditures under GF, and a $360 million increase under GPS, as indicated in Table 5. Note that these estimates of changes in revenue may understate the changes in expenditures because we are not including any increase in natural gas demand in the residential and commercial sectors that could be brought about in response to the increase in electricity prices under these different policies.

We examine the response in demand for primary fuels in the industrial sector using the INSECT model, which is based on the National Energy Modeling System. Table 5 shows that the change in expenditures for coal and oil is positive for all policies, and the change for natural gas is negative for all policies. The model accounts for changes in a dozen other special fuel types, but the changes are trivial or nonexistent. We also find that emissions of carbon associated with industrial fuel consumption increase slightly, in the vicinity of 1 million mtC, as a result of the policies.

Under the AU approach, the total increase in expenditures on primary fuels outside the electricity sector totals $1.4 billion, under GF the increase is $1.2 billion, and under GPS the increase is $1.6 billion. These additional expenditures are added to changes in expenditures for electricity to estimate total changes in expenditures under each approach. The distribution of increased expenditures is fairly even over customer classes under AU and GF. Under AU, residential customers bear 34% of this increase ($4.0 billion), commercial customers bear 26%, and industrial customers bear 40%. Under GF, residential customers bear 34% ($2.1 billion) of the increase in expenditures, commercial customers bear 29%, and industrial customers bear 37%. However, under GPS, industrial customers bear most of the increase in expenditures.

[12] For the commercial sector the long-run price elasticity of demand for natural gas is approximately –1, so even though demand drops in response to change in price, the change in revenues associated with that demand reduction is zero.

Residential customers bear 26% ($0.7 billion) of the increase, commercial customers bear 3% of the increase, and industrial customers bear 71%.

5.4 Economic cost

The change in expenditures is a component of the economic cost of the carbon policy. To estimate economic cost, we measure changes in consumer and producer surplus. We focus on the electricity sector where most of the costs are incurred. Table 5 indicates that, based on the relative magnitude of changes in expenditures, the costs in other sectors may be important but they are likely to be an order of magnitude less than changes in the electricity sector and they are not likely to change the ordering of approaches to allocating allowances in terms of overall social cost, which is our primary interest. Other sources of cost stemming from interactions with pre-existing distortions in factor markets such as the personal income tax may be important but they are not addressed here.

Table 6 examines the change in consumer and producer surplus for 2012 for the 35 million mtC reduction. The decline in consumer surplus is the largest under the AU approach, totaling almost $14 billion. This decline occurs because under AU producers are able to pass on almost all compliance costs of implementing the carbon policy to the electricity consumers. Compliance costs include the cost of capital investments and fuel expenditures relative to the baseline, and the value of emission allowances used in electricity generation. Under AU, firms incur cost in obtaining all of their allowances. In regions with competitive pricing, the cost is reflected in electricity price when the marginal generating unit that determines electricity price has a carbon emissions and associated permit costs. In regions with regulated prices, the firm's payment to obtain emission allowances in the auction is automatically passed through in electricity price.

Under GF, the decline in consumer surplus is $8 billion. As in the AU case, in regions with competitive electricity prices, the allowance value is reflected in electricity price. However, in regions with regulated electricity prices the emission allowances are valued at the original cost to the firm, which is zero for the portion of allowances obtained through GF, so the opportunity cost of that portion of allowances that are used is not reflected in price.

Table 6 shows that under GPS the decline in consumer surplus is only $1.4 billion. This follows directly from the fact that the change in price is the least under GPS, as indicated in Table 3.

The change in producer surplus for 2012 is also reported in Table 6. Noteworthy is the substantial increase of $4.9 billion in producer surplus generated under GF. This increase results because, on average, across the industry there is no cost associated with obtaining emission allowances under GF. In average-cost regions, the value of permits is not reflected in electricity price, which is why the change in electricity price is less than under AU. However, in competitive regions, producers can pass along the opportunity cost of emission allowances used at the marginal generation facility even though the allowances were obtained at zero cost. The result is a substantial increase in producer surplus, at the expense of consumers.

Producer surplus declines by comparable amounts of $1.7 billion under the AU approach and $1.6 billion under GPS, suggesting that, in the one-year snapshot for 2012, producers should have the same attitude toward these two approaches. It is especially interesting to note that producer surplus is comparable even though producers have to pay $14.8 billion for emission allowances under AU, while in the GPS case they obtain them for free.

It is instructive to study why the change in producer surplus could be so small under the AU approach when the costs incurred by industry are so large. We illustrate this with an example for the base time period (approximately 70% of the day) in summer in the ERCOT region (Texas) as shown in Figure 4. The figure illustrates two policy scenarios. The upward-sloping solid line represents the ordering of variable costs in the region in the baseline, absent a carbon policy. The downward step function illustrated by a solid line represents blocks of revenue per MWh of generation (not including transmission and distribution costs). Revenue blocks are ordered by customer class, as indicated at the bottom of the figure. The price of electricity generation for industrial consumers differs from other (i.e., residential and commercial combined) consumers because in the deregulated electricity market of Texas, industrial consumers pay the real-time price (equal to marginal cost) while everyone else pays an average price (i.e., marginal cost averaged over a day). In the baseline, areas E+D represent the approximate difference between revenues and variable costs. Producer surplus will equal the difference between revenues and all costs, including capital costs, which are not represented in the figure.[13]

[13] The numbers we report are pre-tax producer surplus. The Haiku model accounts for local, state, and federal taxes in an aggregate way based on historic tax payments in each region. There is no adjustment made in tax payments in response to the change in producer surplus.

The broken increasing line in Figure 4 represents the variable cost ordering under the AU approach. The ordering differs from the baseline because of the value of emission allowances used by carbon-emitting plants, and because of changes in generation capacity. The broken, decreasing step function represents blocks of revenue under AU. In this case, areas A+B+E represent the approximate difference between revenues and variable costs. The possibility for AU to increase producer surplus is illustrated by the possibility that area A+B is greater than area D. In other words, the increase in revenues is greater than the increase in costs (changes in capital cost are not represented in the figure). In the ERCOT example, the increase in revenues minus variable costs is $122 million**.**

A simple story that may clarify this example is to imagine that there is a region that has only two technologies, with 50% of its electricity generation from a non-emitting nuclear power facility and 50% with a natural gas facility. Since gas generation has greater variable costs, it will be the marginal generating facility. A carbon policy imposes costs on the natural gas facility only. Since the gas facility determines electricity price, revenue goes up for those units, but revenue also goes up for electricity from the nuclear units even though they have no associated increase in cost. So in this case the change in revenues would be greater than the change in costs by a factor of two, causing producer profits to rise due to the imposition of the policy.

In contrast, under the GPS approach, there are two off-setting factors affecting producer surplus. The allocation of allowances at zero cost represents a cost saving relative to AU that is similar to GF. However, under GPS the allowances are allocated on the basis of generation, so firms are forced to compete for allowances by increasing generation at the margin. The subsidy implicit in the allowance allocation is netted against marginal cost, causing electricity prices and producer surplus to fall in competitive regions. In an analogy to the picture for the AU approach in Figure 4, under GPS, producer surplus in the ERCOT region in 2012 falls by $65 million. Under GF, producer surplus increases by $263 million. Similar calculations are made in each of the inter-related 136 electricity markets that are solved for each simulation year in the model, and the calculations are summed to obtain the aggregate estimate for the nation.

The changes in producer surplus and consumer surplus are combined in the third row of Table 6, and they are significantly greater for AU than for the other approaches. However, AU is also distinguished from the other approaches because it is the only one that yields revenue, totaling $14.8 billion. The economic value of this revenue can be measured in a variety of ways and depends on one’s assumption about how the revenue is used. A substantial body of recent literature suggests that if government uses the revenue to decrease pre-existing distortionary taxes, it may have an economic value that is greater than the value from direct redistribution to households (Bovenberg and de Mooij, 1994; Bovenberg and Goulder, 1996; Goulder et al., 1999; Parry, 1995; Parry, Williams and Goulder, 1998). We use a cautious assumption that revenues are returned lump-sum to consumers, the least valuable option identified in the economics literature, in order to provide a lower bound on the value of the revenue. In this case, the revenue redistribution has no positive incentive properties and individual welfare goes up by the face value of the revenue. It is also possible that revenue is wasted, an option we do not entertain.

The fifth row of Table 4 reports the net direct change in welfare summing the changes in the electricity sector and the value of government revenue. The bottom row of the table represents the direct cost-effectiveness of the three policies, which is calculated by dividing the net direct change in welfare by the tons reduced to estimate a welfare cost per ton reduced. The measure of cost-effectiveness described here for the 35 million mtC reduction example is a snapshot of our main finding illustrated previously in Figure 1 for a wide variety of emission targets. From this perspective, the superior performance of AU is striking. With a $25 marginal allowance price, the estimated average societal cost per ton reduced is $26.5 per ton under AU, less than one-third the cost of GF and GPS.

The advantage of the AU approach provides an important illustration of the role that market structure plays in the cost of environmental policy (Oates and Strassman, 1984). In the linked markets solved for in the model, during most hours of the year, marginal generation costs are greater than average generation costs. The difference implies that the value of resources to electricity generation, at the margin, is greater than the willingness to pay of consumers, at least in regulated regions. In this context, an environmental policy that raises electricity price can have economic costs that are less than compliance costs.

5.5 Asset values

In the context of public policy and achieving political consensus for a carbon policy, an important variable is the change in the value of generating assets and the effect on producers. To analyze this, we calculate the net present value of profits over a 20-year horizon from 2001 to 2020 under the baseline, and the change under each approach. The net present value calculation provides a more comprehensive perspective on the effect of a carbon policy on producers than the change in producer surplus for a single year. The change in net present value directly indicates how the value of a firm would be affected under the three approaches.

Figure 5 reports the change in asset value for each major type and vintage of generation capacity. Value is indicated as dollars per MW of capacity. The baseline for existing capacity is generation capacity in 1997. In the middle of the figure is the comparison of change in asset value for all existing capacity under each approach. It is not surprising that producers benefit greatly under GF (as shown by the middle bar for each region) because under this approach existing facilities are given a share of the allowance asset value and there is no offsetting influence of the output subsidy that appears under GPS. Under GF the asset value of allowances totals nearly $22.5 billion. Under the GPS the asset value totals $23.6 billion.

What is surprising is the performance of the AU and GPS approaches. The asset value of existing generation assets is the smallest under GPS. Further, in several regions the value of existing assets actually increases under AU.

The effect of allocation on the profits in the electricity industry produces an apparent paradox: producers can be at least as well off and usually producers are better off paying for emission allowances (under AU) rather than receiving them for free (under GPS). All policies impose a cost through changes in generation capacity that are necessary to reduce emissions—these changes in cost are passed along in the same way under each approach to allocating allowances. More important in differentiating the effect of a policy on electricity price is the cost of obtaining allowances. The AU approach imposes a cost on the firm through payments for allowances. However, AU also leads to the greatest increase in electricity price, which provides a source of revenue that compensates for the increase in cost. GPS, on average, does not impose a cost in the acquisition of allowances. However, it does provide the smallest increase in average electricity price, which erodes the value of assets by reducing the revenue from sales compared to AU. Therefore AU does a better job of preserving asset values because the increase in revenues goes further to offset the increase in cost.

Figure 6 illustrates the change in asset value for all existing generation capacity organized by the NERC subregions in the model. The variation among regions is due to the mix of generation technologies, to interrelationships through transmission sales in the wholesale power market, and especially to the regulatory status and way in which prices are determined in each region. It is also noteworthy that the five regions with the largest increase under GF are those regions that are assumed to have competitive prices in the limited-restructuring scenario.

We examine the importance of regulation and the determination of prices in Figures 7 and 8. These figures disaggregate the national values in Figure 5 into two groups, one for regulated regions (Figure 7) and one for competitive regions (Figure 8). In reviewing the values of existing assets under the two regulatory regimes, the AU approach preserves asset values better than GPS in most cases, as it did in the aggregate in Figure 5. In competitive regions, AU does a noticeably better job at preserving asset values than GPS for existing non-emitting technologies. In this case, the effect of AU on asset values is due strictly to the price effect. One can see that GPS erodes the value of non-emitting assets, even though they have no compliance costs, because it leads to a decline in electricity price in the region.

However, there is a large difference in the performance of the GF approach when comparing the nature of regulation. In regulated regions, grandfathered allowances are valued at zero for cost-recovery purposes while in competitive regions their market value is reflected in price. In competitive regions, for all technology categories except new coal, asset values increase under GF. For existing sources, this is due in part to the allocation of allowances and to the effect of the program on price; for new sources, it is entirely due to the price effect. One category of interest is the non-emitting sources including nuclear, hydroelectric, and renewable generators. These non-emitting sources receive no allowance allocation but also have no costs associated with compliance, so the price effect under GF is plainly evident and the value of the non-emitting assets increases.

We return to Figure 5 to consider the effect on asset values for new facilities. In the aggregate, the change in asset value is negative under the GF approach because new facilities do not receive allowances. The change is positive and it is the greatest under GPS. It is also positive under AU. However, the effect on asset values varies greatly according to the regulatory setting. Figure 7 indicates that in regulated regions the change is positive for both GPS and AU, but Figure 8 indicates that, in competitive regions, the change is positive for all three approaches.

5.6 Sensitivity Analysis

In order to identify the most important factors driving the results, we have investigated the behavior of the three allocation approaches in a variety of special cases. First, we consider an alternative to the GPS approach, labeled “GPS All,” in which emission allowances are allocated to all generators, including nuclear and hydro facilities that were excluded in the previous discussion of GPS. EIA has studied this approach (Beamon, Leckey and Martin, 2001). Compared to GPS, the GPS All approach leads to a dramatic increase in asset values for nuclear and hydro, as would be expected. The effect on each category of asset aggregated at the national level is illustrated in Figure 9.

The increase in asset values for non-emitting sources comes at the expense of values for fossil generation, which receives a smaller portion of the allowance allocation. Nonetheless, there is an increase in asset values when aggregating effects across all existing facilities, compared to GPS. The asset values aggregated across new sources under GPS All is less than in the GPS case because a larger portion of the allowances are allocated to existing sources. Also, GPS All leads to a higher electricity price relative to GPS because the magnitude of the output subsidy per kilowatt hour of production is reduced since the asset value of allowances is spread more widely.

A second sensitivity analysis examined the role of actions on the demand side in meeting emission targets. One proposal from the Progressive Policy Institute (Naimon and Knopman, 1999) would allocate a portion of allowances as a pass through to companies, property owners, and others as a reward for investments in energy-efficient products and processes. We label this case the demand-conservation incentive (DCI) and couple it with GPS for allocation to electricity generators on the supply side. DCI provides an additional demand opportunity cost because each kWh of demand incurs a cost in the forgone opportunity of a share of the allowance asset. Consequently, there is a demand reduction comparable to AU that is not realized in the GPS case otherwise, and the average social cost of DCI falls to almost the level of AU.

The lesson we draw from the DCI approach is that there exist important efficiency gains from achieving reductions on the demand side. Substantial opportunities may exist for energy savings through conservation and demand side efficiency improvements (Interlaboratory Working Group, 2000). To the extent these opportunities exist, the DCI approach achieves emission targets in a more cost-effective way than the AU approach, and does very well compared to GPS.

However, we emphasize there is no existing institution that can replicate in practice the omniscience of our model in identifying and realizing cost-effective investments on the demand side. Previous experience with allocation of emission allowances to reward conservation under the sulfur dioxide trading program were limited and the transaction costs were high because each investment had to validated. Further, to the extent opportunities for demand-side investments exist, we expect the AU approach would already capture them because the increase in price provides a comparable incentive to improve efficiency in demand-side energy use.

In a third sensitivity analysis, we address the assumption of limited restructuring that underlies all the previous results. As an alternative, we consider an accelerated path to nationwide restructuring with competition achieved in all regions by 2008. Again, we look at results for 2012.

Table 4, which describes how prices are determined, suggests that in competitive regions there should be little difference in the price of electricity between the social cost of the AU and

GF approaches. The reason for this similarity is that the opportunity cost of allowances at marginal generation facilities is added to marginal production costs in equal fashion for AU, GF, and GPS. However, in the GPS approach there is an additional factor—stemming from the output subsidy implicit in the allocation of allowances—that sets that policy apart. Figure 10 illustrates the change in electricity price with nationwide restructuring. The change is almost the same for the AU and GF approaches while the change under GPS is negative—that is, the output subsidy outweighs the greater compliance costs under GPS and electricity price falls by almost 3%.

Figure 11 illustrates the average social cost under nationwide restructuring. One may reason the marginal cost would be the same for AU and GF, since electricity price is similar. This assumption would seem to follow from the fact the asset value of the allowance allocation under GF goes to firms and affects producer surplus, but does not affect marginal cost. We find the conjecture is approximately true but it does not hold to be precisely true for three reasons.

One reason is in the baseline: carbon emissions are 665 million mtC under nationwide restructuring compared to 626 million mtC under limited restructuring. The difference in emissions in the baseline is because there is less generation from new gas-fired facilities and more generation from existing coal-fired facilities under nationwide restructuring. The results in Figure 11 illustrate reductions to 591 million mtC under each approach, which is the emission target achieved in the previous numerical analysis. Hence, the emission reduction required is much greater.

A second reason the AU and GF approaches do not have identical social costs under nationwide restructuring has to do with stranded cost recovery. The allocation of allowances under GF is a large transfer of wealth that directly offsets, to a large degree, the measure of stranded costs to be recovered. Consequently, electricity price and consumption will vary by region and timeblock compared to AU; fuel use will vary as well, with the GF policy leading to slightly more gas-fired generation. The total quantity of electricity consumption is similar between AU and GF. In contrast, the output subsidy implicit in GPS leads to more gas-fired generation than the other approaches and total generation is almost equal to baseline generation.

To better understand the role of pricing, we analyzed a fictional case in which the entire nation remained under regulated pricing. According to Table 4, one would conjecture that under regulated pricing, the change in electricity price is equal for GPS and GF. The reason for this is because the ordering of variable costs under each policy is identical—both approaches include the opportunity cost of allowances as part of production costs. Total cost also will include production costs and will account for the value of allowances that are distributed to firms. Under the GPS and GF approaches, the value of allowances reduces total cost in each case.

We find the conjecture is approximately true but it does not hold to be precisely true due to changes in the geography of electricity generation over time. The GF approach allocates allowances based on historic generation, while GPS updates the allocation of allowances based on generation in the future. There is no reason that the current geographic pattern of electricity generation will match the pattern in the future. Hence, the allocation of allowances to regions of the country varies under the two policies, and so does the calculation of total cost (net of allowance allocations). Subject to this subtlety, however, our intuition about the approaches is borne out in the model.

6. Conclusion

Many previous analysts assume that the method of emission allowance allocation is not important to the performance of a trading system, often characterizing it simply as a wealth transfer. Indeed, the potential wealth transfer in a carbon emission-trading program is enormous. However, this paper demonstrates that the means of allocating allowances is extremely important to the efficiency and cost of achieving carbon reductions. We investigate the cost-effectiveness and distributional effects of three alternative approaches for distributing carbon emission allowances under an emission-trading program in the electricity sector. A somewhat qualitative characterization of the relative performance of each allocation approach is presented in Table 7. The table has four scores that are used to illustrate the performance of each approach, relative to the best and worst performance under each criteria.

When viewing the merits of alternative policies for allocating emission allowances, the two highly visible and politically important variables of electricity price and natural gas price move in opposite directions. The AU approach leads to the highest electricity price and lowest natural gas price among the policies considered. GPS leads to the lowest electricity price and highest gas price. GF is an intermediate case in both measures.

However, when we view the policies from a perspective of social cost, the AU approach is dramatically more cost-effective—roughly one-half the economic cost of the other two. We measure the change in cost as the change in consumer and producer surplus in the electricity sector plus the benefits of lump-sum redistribution of government revenues. AU's relative cost-effectiveness holds up over a wide range of emission reduction targets and under a variety of assumptions about the nature of future regulation and competition in the electricity sector.

Viewed under the assumption of an accelerated transition to competition in the electricity sector, the GF approach converges to the AU approach in terms of cost-effectiveness. However, the GPS approach remains substantially more expensive.

Differences in the cost of the three approaches flow from the effect of each approach on electricity price. GPS allocation (on the basis of generation) constitutes an incentive to increase electricity generation. This incentive resembles an output subsidy and mitigates electricity price increases, but it raises economic cost. The way electricity prices are determined in practice departs from economic efficiency, and the output subsidy amplifies the distortion away from efficiency in most electricity markets and time blocks. In contrast, AU serves to increase electricity prices the most, but the efficiency cost of the changes in prices is less than the cost of price changes under the other approaches.

Consumers are benefit the most under GPS when examining just the change in electricity price. However, AU is unique because it raises substantial revenues that, when taken into account, make this approach preferable for households. How auction revenues are used is important to the societal cost of the AU approach. We assume revenues are used in the least efficient way that is discussed in the economics literature, which is direct redistribution to households instead of reducing pre-existing taxes. Nonetheless we chose to model direct redistribution to households because it is the most cautious representation of the benefits of recycling auction revenues. Even under this approach, AU is roughly one-half the cost of the other approaches. If the AU revenues are used in a more efficient way, for example to reduce pre-existing taxes, AU's cost-effectiveness would increase substantially further. However, the way revenues are used to reduce pre-existing taxes could affect producer or consumer surplus rankings shown in Table 7.

Producers can expect to do the best under GF because this approach represents a substantial transfer of wealth to producers from consumers. In fact, producer profits and asset values increase substantially compared to the baseline (absent a carbon policy), making producers better off with a carbon policy than without, but leaving consumers substantially worse off. Even though GF appeared to be the intermediate approach with respect to its effect on electricity and natural gas prices, it is the most extreme approach with respect to transfers of wealth. The AU and GPS approaches have much more moderate distributional effects and therefore we focus more attention on a comparison of these two alternatives.

Producers can expect to do at least as well in aggregate under AU, compared to GPS, while owners of existing assets can expect to do substantially better under AU. This finding raises an interesting paradox: producers do better paying for emission allowances (through the AU approach) than receiving them for free (under the GPS approach). The reason for this is that GPS yields the lowest electricity price, which erodes the value of existing assets. AU yields the highest electricity price, which preserves or enhances the value of many assets. Although consumer expenditures increase under AU, substantial revenues also are raised and serve as compensation to consumers. A portion of revenues could be diverted to compensate producers as well, perhaps through a hybrid program that combined AU with GPS during a transition period, culminating in an auction of all allowances in future years. In addition, a portion of revenues under AU, or direct allocation of some allowances, could be directed to support energy conservation and other benefit programs.

Finally, AU also has institutional features that make it more readily expandable to an economywide approach to regulating carbon emissions, which most economists prefer to an approach focused just on one sector. The focus here on the electricity sector only is of relevance nonetheless, even in the context of an economywide carbon policy. Although the electricity sector is responsible for just over one-third of carbon emissions in the US, it would be expected to contribute two-thirds to three-quarters of the emission reductions under a policy that encompassed the entire economy in a cost-effective way. For the AU, the effects we model correspond directly to an economywide policy that encouraged the specified amount of emission reduction in the electricity sector.

The bottom line is that the AU approach weighs in at substantially less economic cost to society than either of the two gratis approaches to allocating allowances. From an economic perspective, this is the most important criteria listed in Table 7. AU also provides policymakers with flexibility, through the collection of revenues that can be used to meet distributional goals or to enhance the efficiency of the AU even further by reducing pre-existing taxes. Because the AU approach is so cost-effective, a corresponding a carbon policy will have less effect on economic growth than under the other approaches. This attribute provides perhaps the most significant form of distributional benefit.

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Table 1. Listing of NERC subregions, the year marginal cost pricing begins, and subregions covered by cap and trade NO_X policies under modeled scenarios.

NERC Subregion	Geographic Area	*Year Marginal Cost Pricing Regime Begins* — Restructuring Scenario		SIP NO_X Trading Region
		Limited	*Nationwide*	
ECAR	MI, IN, OH, WV; part of KY, VA, PA	-	2004	ECAR
ERCOT	Most of TX	2002	2002	
MAAC	MD, DC, DE, NJ; most of PA	2000	2000	MAAC
MAIN	Most of IL, WI; part of MO	-	2004	MAIN
MAPP	MN, IA, NE, SD, ND; part of WI, IL	-	2008	
NE	VT, NH, ME, MA, CT, RI	2000	2000	NE
NY	NY	1999	1999	NY
FRCC	Most of FL	-	2008	
STV	TN, AL, GA, SC, NC; part of VA, MS, KY, FL	-	2008	STV
SPP	KS, MO, OK, AR, LA; part of MS, TX	-	2008	
NWP	WA, OR, ID, UT, MT, part of WY, NV	-	2008	
RA	AZ, NM, CO, part of WY	-	2004	
CNV	CA, part of NV	1998	1998	

Table 2. Distinguishing Features of Economic Regulation Scenarios in 2008.

	Economic Regulation	
	Limited Restructuring	**Nationwide Restructuring**
Ratio of Technical Parameter Values 2008 to 1997		
Maximum Availability Factor	1.0205	1.0411
Heat Rate	0.9864	0.9730
General and Administrative Cost	0.7500	0.6741
Non-Fuel O&M Cost	0.7642	0.7001
Renewables Portfolio Standard	None	RPS with $17 per MWh price cap on tradable renewable credits (target 2% above base)
Transmission Capability	-------	10% more in 2008 than under baseline

Table 3. Changes from limited restructuring baseline for generation, capacity, electricity price, fuel prices, and carbon emission allowance price in 2012 (35 million mtC reduction).

	Baseline	Au	GF	GPS
Generation (billion kWh)				
Coal	1,799	-152	-165	-183
Gas	1,405	+63	+104	+156
Wind	30	+6	+10	+6
Other	980	+6	+9	+4
Total	4,214	-77	-42	-17
Capacity (thousand MW)				
Coal	322	-2	-14	-2
Gas	332	-12	+9	+2
Wind	10	+2	+4	+2
Other	246	-2	-1	-3
Total	911	-14	-	-1
Prices (1997 dollars)				
Electricity Price ($/MWh)	61.0	+3.7	+2.1	+0.4
Fuel Cost ($/mmBtu)				
Coal	0.93	-0.03	-0.03	-0.04
Gas	3.66	+0.12	+0.19	+0.22
Carbon Allowance ($/ton)	0	+25	+38	+40

Table 4. Stylized characterizatoin of how the price for generation is determined.

Total Cost ($):

capital + FOM + fuel + VOM + emission allowances [**Au**]

Variable Cost Ordering ($/MWh):

fuel + VOM + emission allowances - subsidy [**GPS**]

Price ($/MWh):

Regulated Price **=** Average Cost = (Total Cost ÷ Production)

=> Price [**Au**] **>** Price [**GF, GPS**]

Competitive Price = Variable Cost

=> Price [**Au, GF**] > Price [**GPS**]

Table 5. Changes from baseline in expendutures for electricity and primary fuels by customer class in 2012 (35 million mtC reduction).

(billion 1997 dollars)	**Au**	**GF**	**GPS**
Residential			
Electricity	+3.8	+2.1	+0.3
Gas	+0.2	+0.3	+0.4
Total	+4.0	+2.4	+0.7
Commercial			
Electricity	+3.1	+2.1	+0.1
Gas	-0.0	-0.0	-0.0
Total	+3.1	+2.1	+0.1
Industrial			
Electricity	+3.7	+1.8	+0.6
Coal	+0.0	+0.0	+0.0
Oil	+1.1	+0.9	+1.2
Gas	-0.0	-0.0	-0.0
Total	+4.8	+2.7	+1.9

Table 6. Change in economic surplus, and cost-effectiveness of policies in 2012. (billion 1997 $; 35 million mtC reduction)

	Au	GF	GPS
Consumer Surplus	-13.9	-8.0	-1.4
Producer Surplus	-1.7	+4.9	-1.6
Sum	*-15.6*	*-3.1*	*-3.0*
Revenue to Government	+14.8	0.0	0.0
Net Direct Surplus	*-0.9*	*-3.1*	*-3.0*
Cost-Effectiveness ($/ton of Carbon)	26.5	88.7	87.2

Table 7. Qualitative comparison of criteria for evaluating allocation approaches.

Best ● ◓ ◒ ○ *Worst*	**Auction**	**Grandfathering**	**GPS**
Electricity Sector:			
Societal Cost	●	○	○
Consumers	●	○	◒
Producers (All)	◒	●	○
Electricity Price	○	◒	●
Outside Electricity Sector:			
Gas Price	●	◒	○
Can address tax interaction effects?	●	○	◓
Expandable outside electricity sector?	●	◒	○

Figure 1. Social cost of allocation approaches over a range of emission targets.

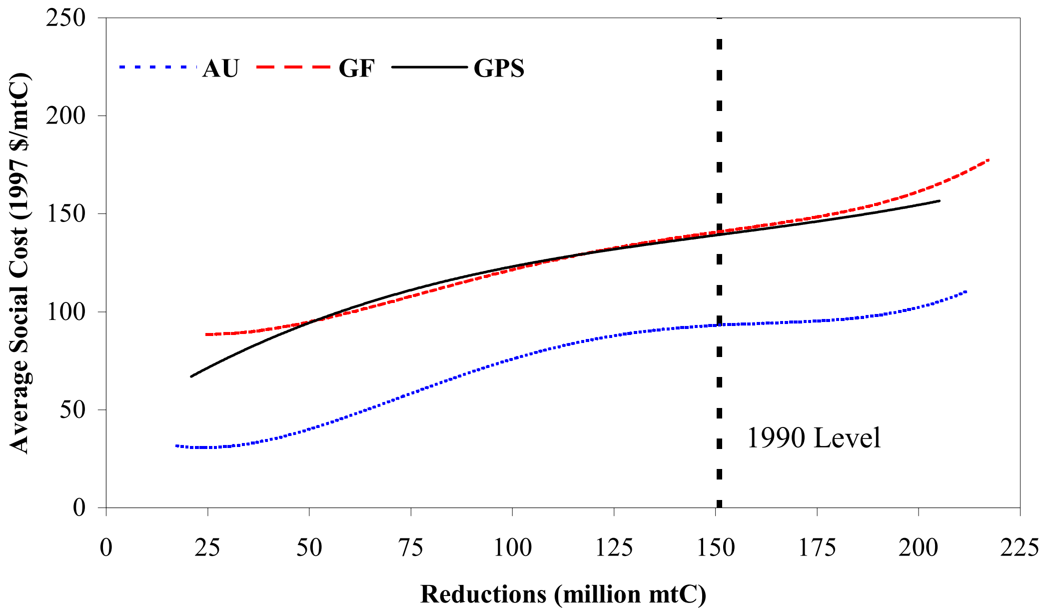

Figure 2. Allowance price for different allocation approaches over a range of emission targets.

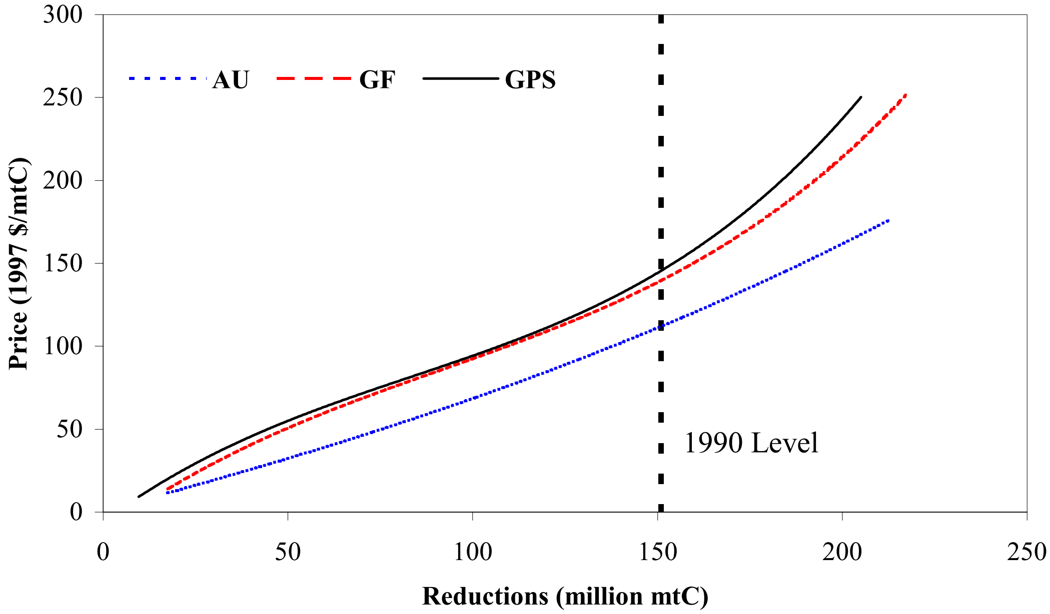

Figure 3. Percent change in electricity and natural gas prices from baseline in 2012 due to a 35 million metric ton reduction in carbon emissions.

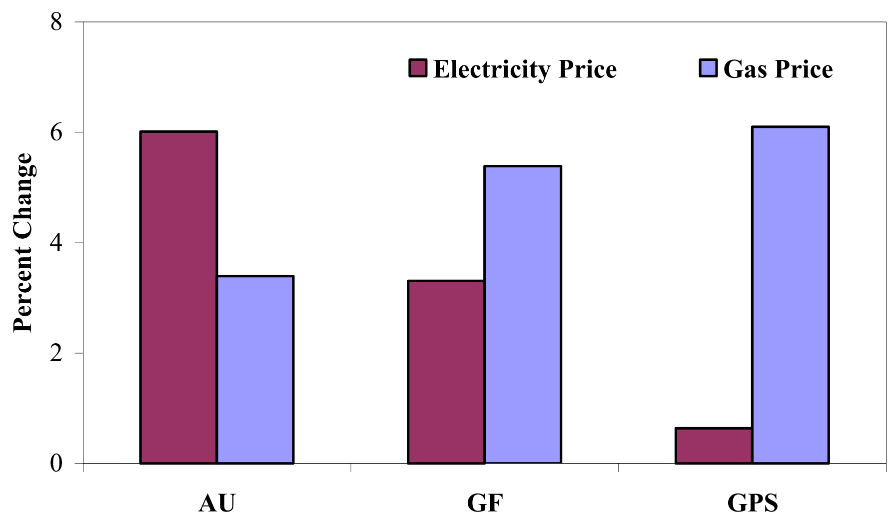

Figure 4. Producer costs and revenues for base time period in summer baseload timeblock in ERCOT (Texas) in 2012.

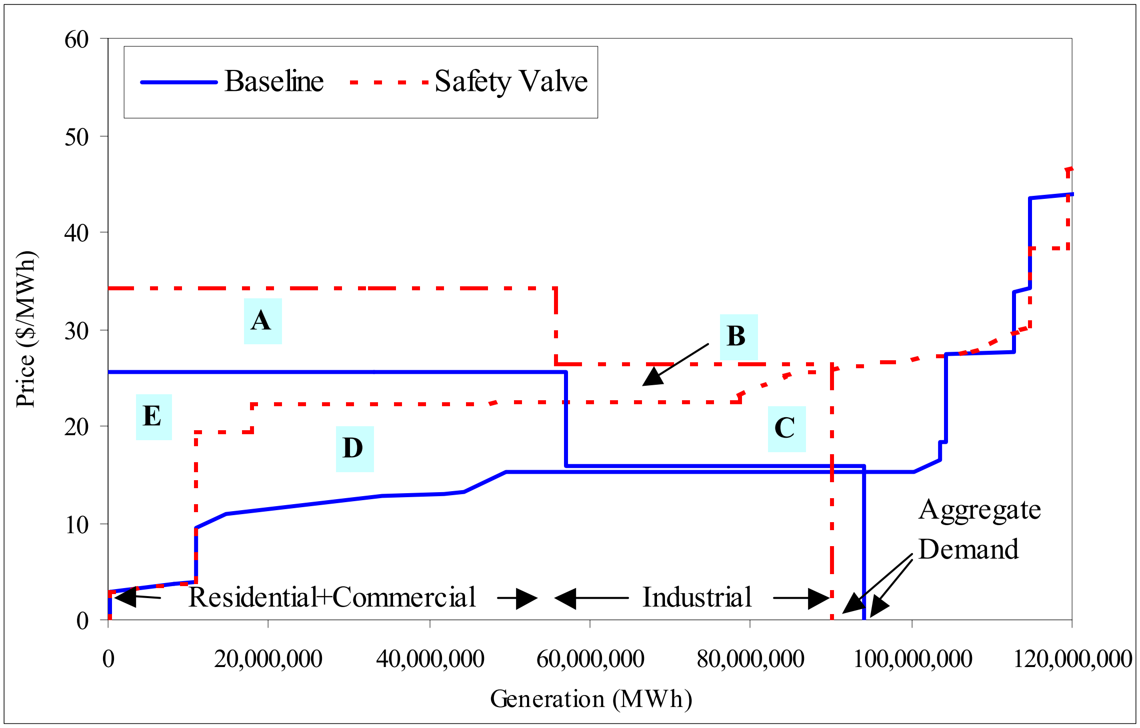

Figure 5. National aggregate changes in asset values by technology and vintage (1997 $/MW in 2001; 35 million mtC reduction).

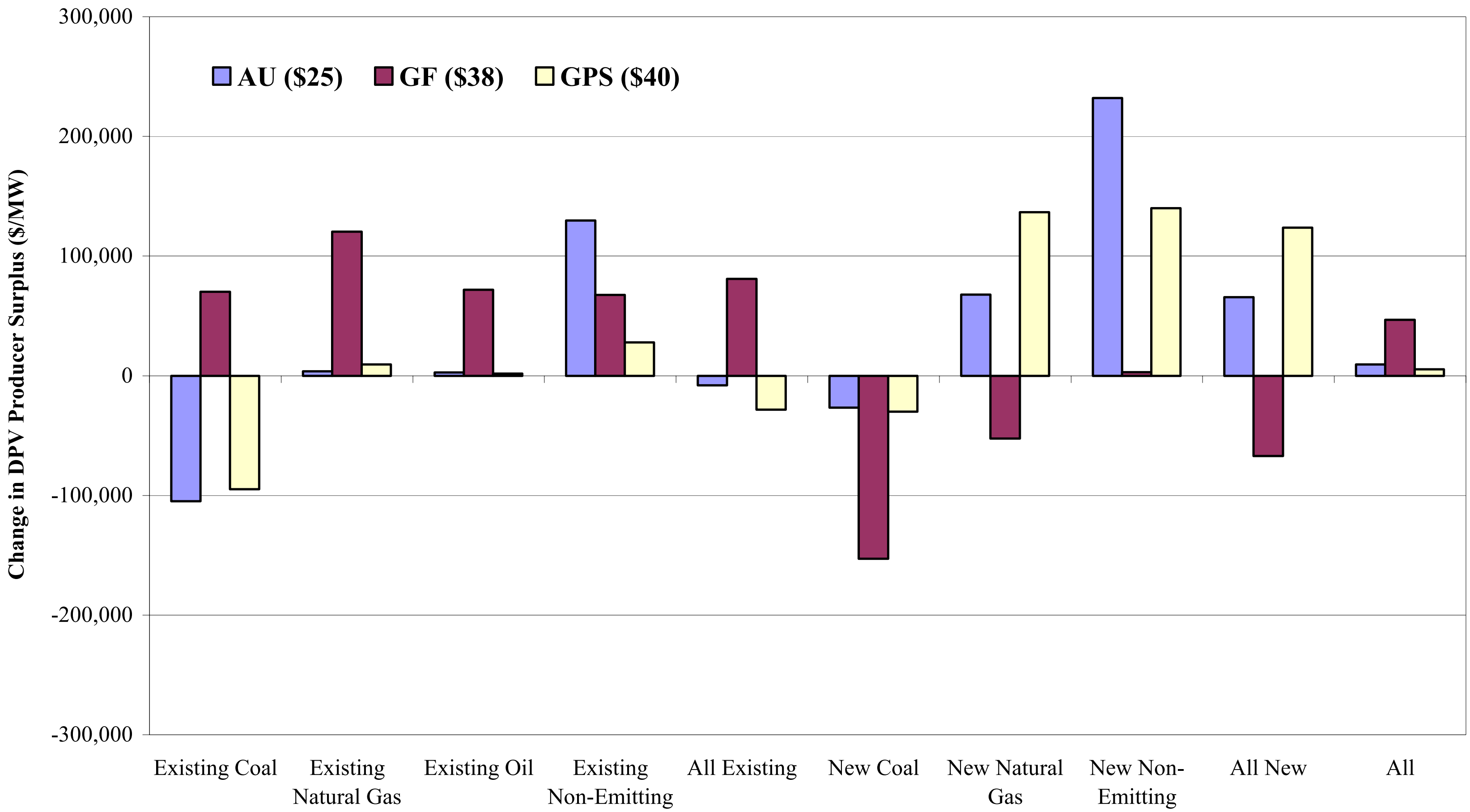

Figure 6. Change in the value of assets existing in 1997, by region (1997 $/MW in 2001; 35 million mtC reduction).

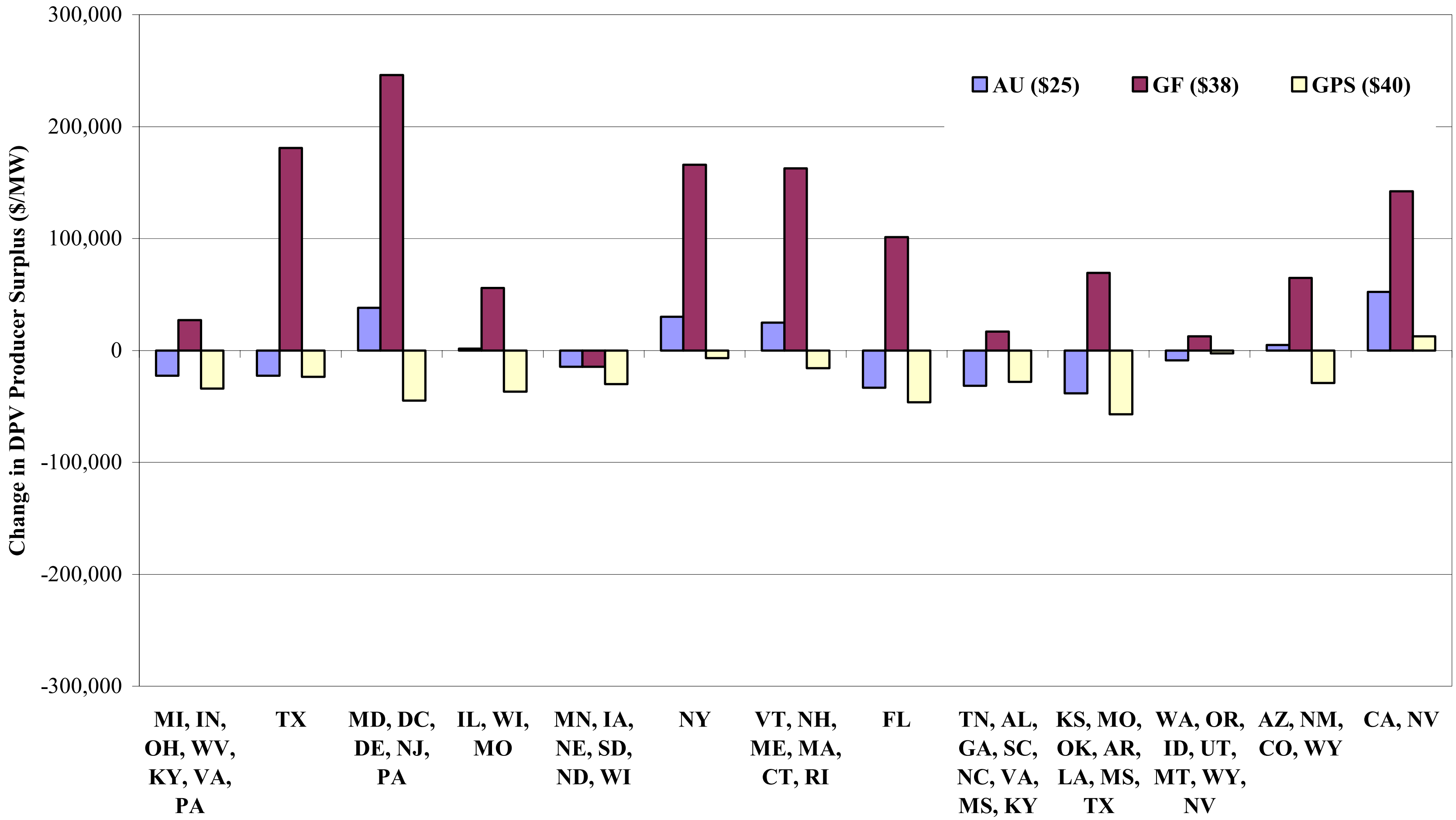

Figure 7. Aggregate changes in asset values by technology and vintage for regions with regulated prices (1997 $/MW in 2001; 35 million mtC reduction).

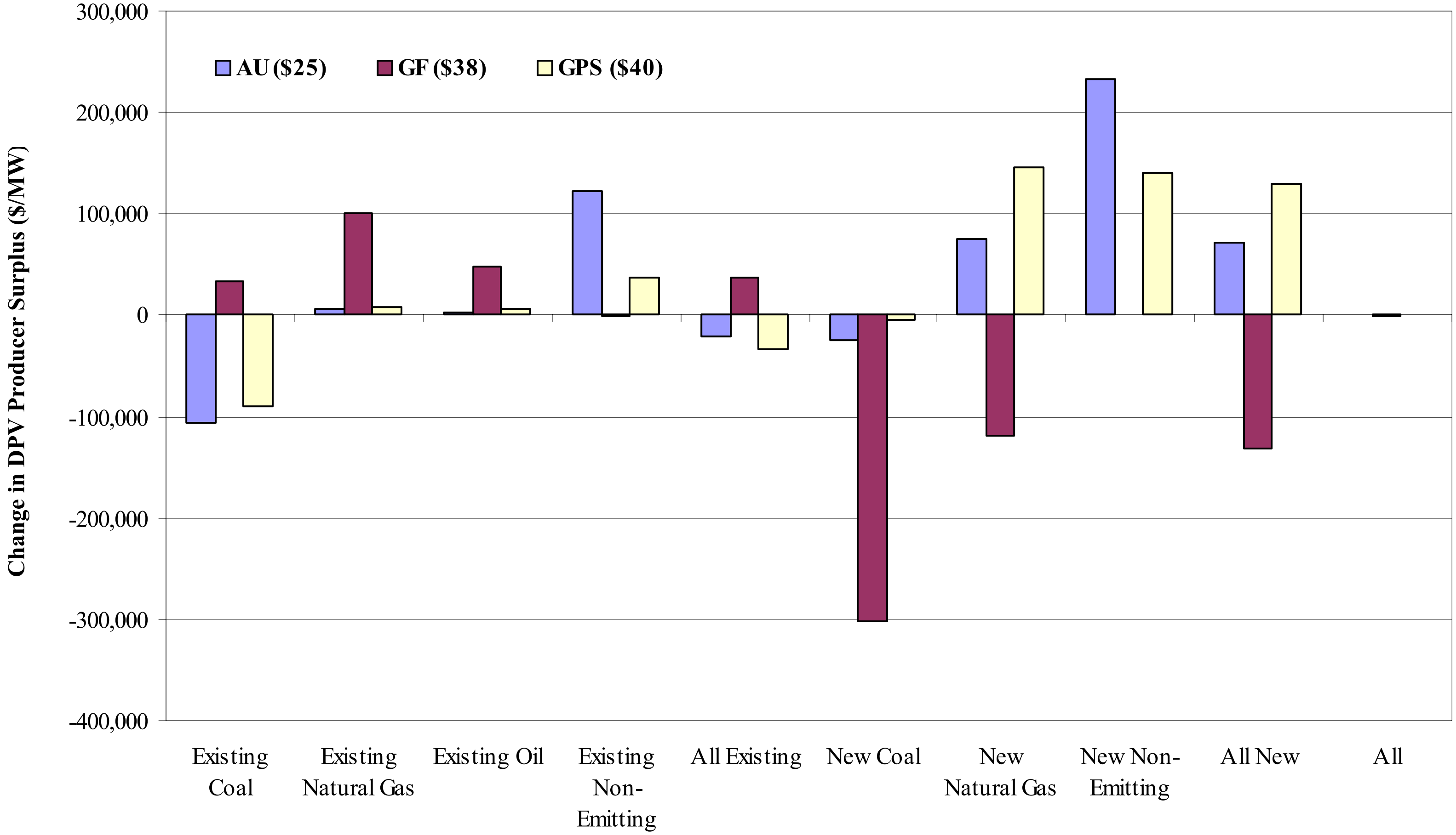

Figure 8. Aggregate changes in asset values by technology and vintage for regions with competitive prices (1997 $/MW in 2001; 35 million mtC reduction).

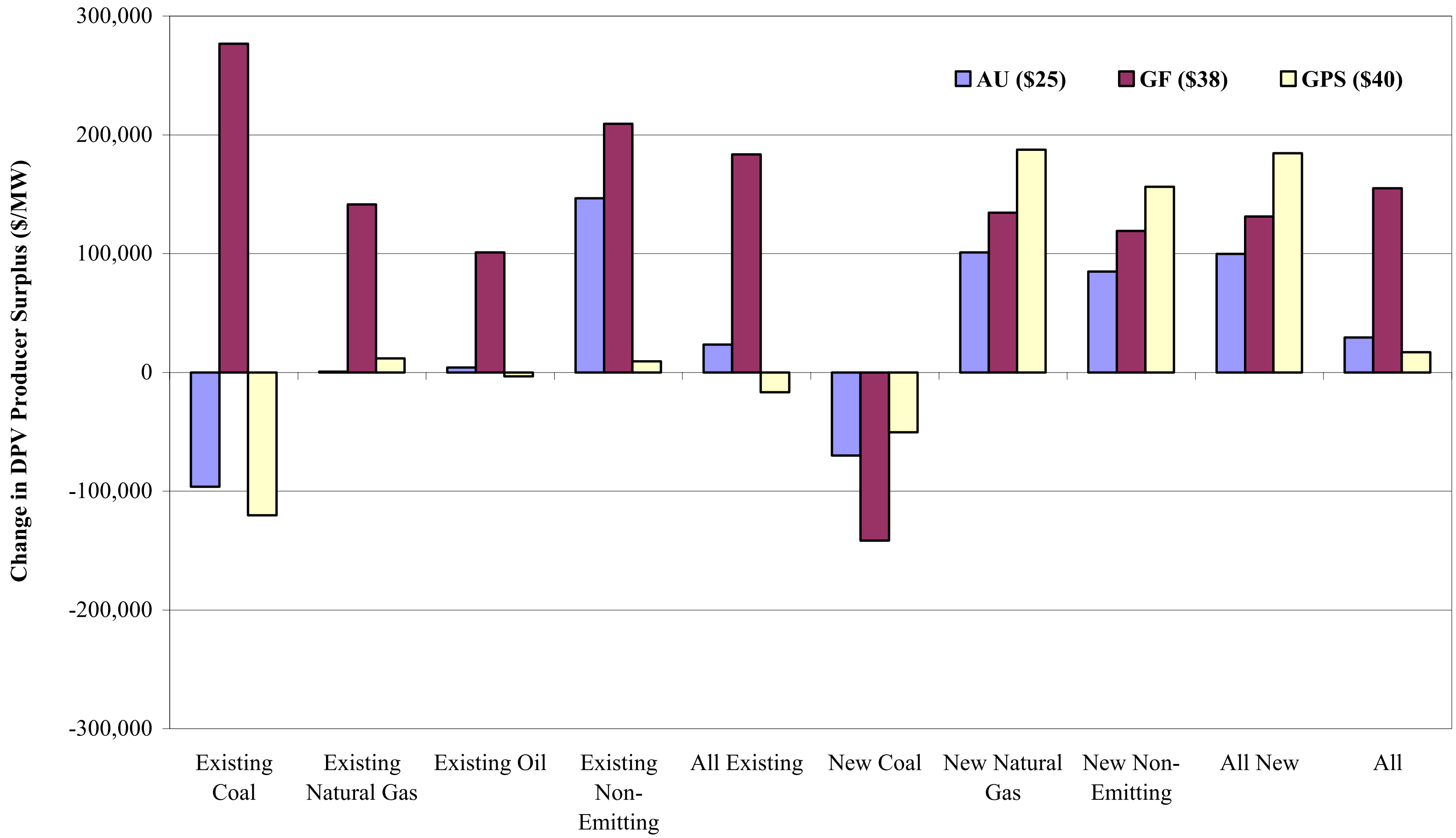

Figure 9. Aggregate changes in asset values at the national level, including the GPS All approach (1997 $/MW in 2001; 35 million mtC reduction).

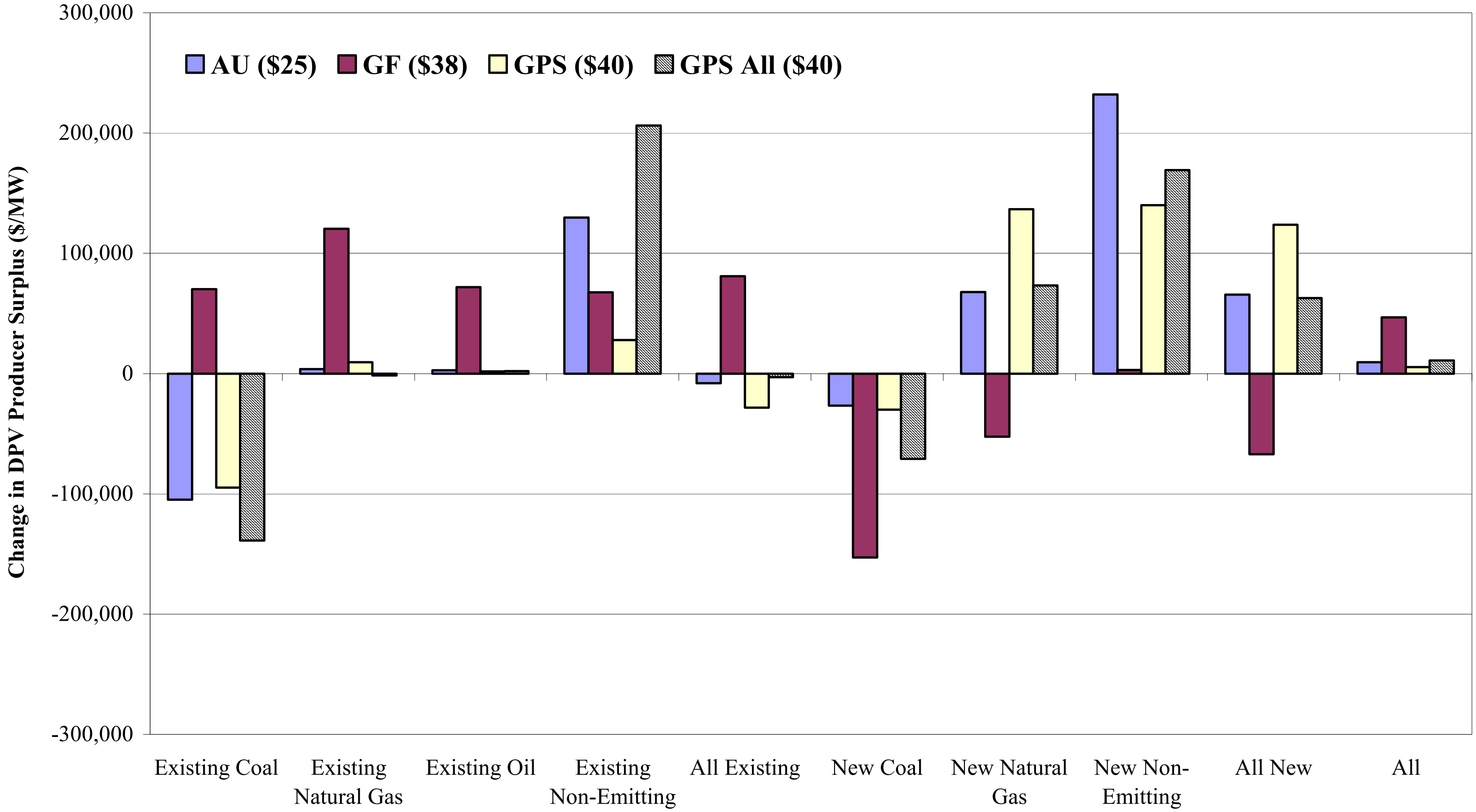

Figure 10. The change in electricity price with limited restructuring compared to nationwide restructuring. Emission reductions vary in order to achieve a common emission target.

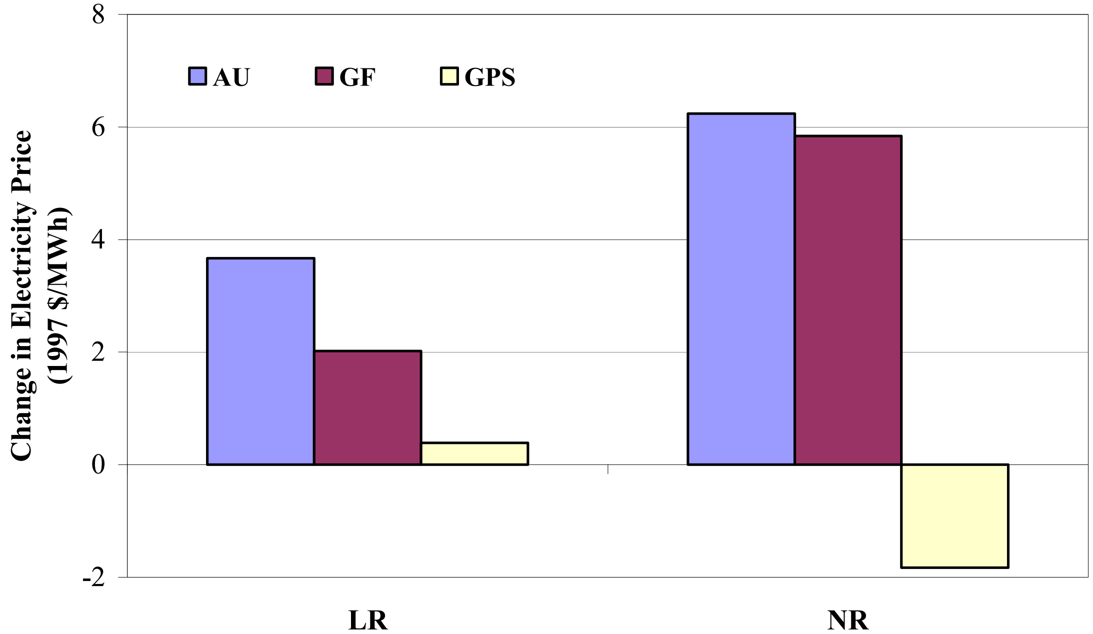

Figure 11. Average social cost under limited restructuring compared to nationwide restructuring.