ANALYSIS OF THE ELECTRICITY PRICE IMPACTS OF ALTERNATIVE CARBON EMISSION CAP-AND-TRADE PROGRAMS IN THE MIDWEST

prepared on behalf of

Indiana Municipal Power Agency, Madison Gas and Electric Company, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, and WPPI Energy

prepared by

Bruce Edelston
Energy Policy Group, LLC

Dave Armstrong
Laurence D. Kirsch
Mathew J. Morey
Christensen Associates Energy Consulting LLC

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EXECUTIVE SUMMARY

Indiana Municipal Power Agency, Madison Gas and Electric Company, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, and WPPI Energy (hereinafter "the Midwest Consumer Utilities") sought estimates of the electricity cost and rate impacts of various means of allocating or auctioning greenhouse gas (GHG) emissions allowances under a cap-and-trade system. The interest in this matter arises, at least in part, from the progress of the Midwestern Greenhouse Gas Reduction Accord and the likely issuance of a model cap-and-trade rule in 2010. It also arises from the several cap-and-trade proposals that were offered in the 110th Congress and that may serve as the basis for legislation that comes before the present Congress. To that end, the Midwest Consumer Utilities asked the Energy Policy Group and Christensen Associates Energy Consulting to quantify the cost and rate impacts. The quantification methodology consequently developed in this study allows the Midwest Consumer Utilities to project the potential rate impact of various legislative approaches on their customers, including business and industry, with implications for the economies in their respective states. Estimates of rate impacts under cap-and-trade designs will also be useful in informing policymakers of the relative costs to consumers of various approaches to implementing any cap-and-trade regime.

The study analyzed three cases representing low, moderate, and high GHG allowance prices. We did not attempt to forecast allowance prices, but rather relied on forecasts developed by others – most notably the Energy Information Administration, the Environmental Protection Agency, and the Massachusetts Institute of Technology. We reviewed these studies and used averages of selected model runs. In following this procedure, we do not endorse any particular set of assumptions or results, but we do derive rate and cost impacts that are consistent with mainstream published studies of the economic impacts of GHG proposals. Because of the uncertainties inherent in any forecast of allowance prices, actual allowance prices may differ from those of the forecasts we used. In particular, if new technologies to reduce the GHG emissions of electricity production do not become available at sufficiently low cost or are delayed, then the costs of GHG compliance may be extremely high and rate impacts could exceed those forecast in this study.

For each of the three cases representing low, moderate and high GHG allowance prices, we looked at six scenarios representing different treatment of the revenues raised by the cap-and-trade program. The six scenarios are as follows:

- Scenario 1. Auction of allowances with no revenues recycled to load-serving entities (LSEs) for rate relief
- Scenario 2. Auction of allowances with 50% of revenues recycled to LSEs for rate relief on the basis of GHG emissions shares
- Scenario 3. Auction of allowances with 50% of revenues recycled to LSEs for rate relief on the basis of retail load shares.

Scenario 4.	No-cost allocation to LSEs based on GHG emissions shares.
Scenario 5.	No-cost allocation to LSEs based on retail load shares.
Scenario 6.	No-cost allocation of allowances to LSEs, with 50% based on GHG emissions shares and 50% based on retail load shares.

The analysis definitively shows that alternative policies regarding GHG limits and auction revenue allocation have major cost and rate impacts. In particular, the method chosen to distribute allowances and recycle any auction revenues will dramatically affect the cost of compliance and therefore costs to consumers and impacts to the economy, particularly in coal intensive states in the Midwest. Table ES-1 shows average price increases relative to retail prices in 2005 over the 2012-2030 period for each of the allowance price cases (low, moderate or high), each of the scenarios, and each of the seven states included in this study. The rightmost "All" column presents a weighted average (based on 2005 loads) of the price increases for the seven states. For the seven states in aggregate, average price increases range up to 79% for the full auction (no revenue recycling) scenario.

TABLE ES- 1
AVERAGE PRICE INCREASES 2012 – 2030
BY CASE, SCENARIO AND STATE

	IN	IA	MN	MO	ND	SD	WI	ALL
Low								
Scenario 1	30%	23%	20%	23%	32%	14%	19%	24%
Scenario 2	18%	13%	11%	12%	19%	8%	11%	14%
Scenario 3	21%	15%	11%	13%	23%	6%	11%	15%
Scenario 4	5%	3%	3%	1%	6%	1%	3%	3%
Scenario 5	11%	6%	3%	4%	14%	-3%	4%	6%
Scenario 6	8%	5%	3%	3%	10%	-1%	3%	5%
Moderate								
Scenario 1	74%	57%	48%	56%	79%	35%	46%	58%
Scenario 2	49%	37%	32%	35%	53%	22%	30%	38%
Scenario 3	55%	40%	31%	37%	61%	18%	31%	40%
Scenario 4	24%	17%	15%	13%	26%	10%	15%	17%
Scenario 5	36%	23%	14%	19%	43%	1%	16%	23%
Scenario 6	30%	20%	15%	16%	35%	5%	15%	20%
High								
Scenario 1	101%	77%	65%	76%	108%	48%	63%	79%
Scenario 2	71%	53%	45%	50%	76%	32%	44%	54%
Scenario 3	78%	57%	45%	54%	86%	27%	45%	58%
Scenario 4	41%	30%	26%	24%	44%	17%	25%	30%
Scenario 5	55%	37%	25%	31%	64%	6%	27%	37%
Scenario 6	48%	33%	25%	28%	54%	12%	26%	34%

Table ES-2 shows the annual net cost to ratepayers in the last year of the study (2030) in each of the states under each of the allowance price and scenario combinations.

TABLE ES- 2
ANNUAL NET COST TO RATEPAYERS IN 2030
(IN MILLIONS OF 2005 DOLLARS)

	IN	IA	MN	MO	ND	SD	WI	TOTAL
Low								
Scenario 1	$3,407	$1,229	$1,593	$2,009	$ 394	$166	$1,848	$10,646
Scenario 2	$2,282	$ 818	$1,073	$1,252	$ 266	$108	$1,239	$ 7,038
Scenario 3	$2,541	$ 882	$1,057	$1,351	$ 306	$87	$1,276	$ 7,500
Scenario 4	$1,156	$ 407	$ 554	$ 496	$ 139	$49	$ 631	$ 3,432
Scenario 5	$1,675	$ 534	$ 520	$ 694	$ 218	$7	$ 705	$ 4,353
Scenario 6	$1,416	$ 471	$ 537	$ 595	$ 178	$28	$ 668	$ 3,893
Moderate								
Scenario 1	$8,164	$2,945	$3,818	$4,815	$ 944	$399	$4,428	$25,513
Scenario 2	$6,004	$2,157	$2,820	$3,362	$ 699	$286	$3,260	$18,588
Scenario 3	$6,502	$2,279	$2,788	$3,552	$ 774	$246	$3,331	$19,742
Scenario 4	$3,845	$1,368	$1,823	$1,909	$ 454	$173	$2,092	$11,664
Scenario 5	$4,840	$1,612	$1,759	$2,289	$ 605	$92	$2,234	$13,431
Scenario 6	$4,342	$1,490	$1,791	$2,099	$ 530	$133	$2,163	$12,548
High								
Scenario 1	$10,575	$3,815	$4,946	$6,236	$1,222	$516	$5,736	$33,046
Scenario 2	$8,511	$3,062	$3,992	$4,848	$ 988	$409	$4,620	$26,430
Scenario 3	$8,987	$3,178	$3,962	$5,030	$1,060	$370	$4,688	$27,275
Scenario 4	$6,448	$2,308	$3,039	$3,461	$ 754	$301	$3,504	$19.815
Scenario 5	$7,399	$2,541	$2,978	$3,824	$ 899	$224	$3,640	$21,505
Scenario 6	$6,923	$2,425	$3,009	$3,642	$ 826	$262	$3,572	$20,659

Tables ES-1 and ES-2 demonstrate that billions of dollars of electric consumer payments are contingent upon the particular approach chosen to distribute allowances and recycle the auction revenues of a cap-and-trade regime. Allocating emissions allowances to LSEs or otherwise recycling auction revenues to consumers substantially mitigates the cost impacts of GHG limits upon consumers and thereby mitigates the massive redistribution of wealth that would otherwise accompany the imposition of GHG limits. Regardless of the handling of auction revenues, however, GHG limits will still lead to substantial rate increases.

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1. INTRODUCTION

Indiana Municipal Power Agency, Madison Gas and Electric Company, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, and WPPI Energy (hereinafter "the Midwest Consumer Utilities") seek estimates of the electricity cost and rate impacts of various means of allocating or auctioning greenhouse gas (GHG) emissions rights under a cap-and-trade system. The Midwest Consumer Utilities' interest in this matter plainly arises, at least in part, from the progress of the Midwestern Greenhouse Gas Reduction Accord and the likely issuance of a model cap-and-trade rule by early 2010. It also arises from the several cap-and-trade proposals that were offered in the 110th Congress and that may serve as the basis for legislation that comes before the present Congress. The cost and rate impact estimates developed in this study will be important to the Midwest Consumer Utilities in determining any positions that they may wish to take in the on-going policy debate at the regional and federal levels, and in anticipating how they may best respond to whatever policy eventually becomes law.

This report is organized as follows. First, we provide background on the features of cap-and-trade programs. We then discuss the methods by which we develop our cost and rate impact estimates. This includes descriptions of required emission reductions "cases" (i.e., low, moderate, and high) and of the "scenarios" for selling or allocating allowances to load-serving entities. In Section 4 we discuss data sources and related assumptions. Section 5 presents a summary of the results for the states that were included in our analysis (Indiana, Iowa, Minnesota, Missouri, North Dakota, South Dakota and Wisconsin.) Appendix A provides details on data sources for the allowance prices.

2. BACKGROUND

Cap-and-trade programs place limits on the amounts of pollutant emissions produced by some or all sectors of the national economy. For a greenhouse gas (GHG) program, the cap is the total amount of GHG emissions that will be allowed across all regulated sectors. That total cap is then assigned among the various sectors of the economy to give each covered sector a limit on emissions. Allowable emissions may be allocated among sectors according to their relative contributions to total emissions in a selected historical year (the "Base Year"), and can remain constant through time or be updated periodically. Emission allowances are likely to be created in units that are convenient for trading purposes, such as each allowance representing a single metric ton of emissions. These allowances, which are also called "emission permits," become a tradable commodity that can be bought, sold, or even retired (to prevent emissions associated with the allowance). Parties who can reduce their emissions relatively cheaply will tend to sell their emissions allowances to parties who can only reduce their emissions at high expense.

Cap-and-trade programs are not new. They have been used for SO_2 and NO_x emissions regulation in the United States, and for GHG regulation in Europe. GHG cap-and-trade systems are also currently operating in the Northeast U.S., are being planned for California, and are currently under consideration in the Midwest in response to an initiative by the Midwest Governors Association. Relative to taxing emissions, cap-and-trade programs have the advantages of "assuring" that emissions targets are met and possibly providing a means of mitigating the substantial wealth transfers than can accompany the introduction of GHG markets. But these programs also have the relative disadvantages of creating substantial financial risks for emitters and their customers because of uncertain GHG allowance prices, of creating new opportunities for market manipulation, and of rent-seeking manipulation of the processes by which Congress or government agencies determine the distribution of either auction revenues or no-cost allowances.

In any cap-and trade program, there are numerous issues that must be addressed. Among the most critical are the following:

- What is the timetable for reductions? By how much must emissions be reduced, and how soon? Are there technological solutions for reduction and when can they be deployed?
- To what extent will allowances be auctioned to the highest bidders or allocated at no cost to affected parties? If they are auctioned, what parties will receive the auction revenues and for what purposes?
- May emitters meet reduction requirements by buying offsets?[1] Must they buy offsets only from domestic sources, or can they also acquire offsets internationally? Are the amounts of allowable offsets capped?
- What sectors of the economy are covered by the caps? Will the cap-and trade program cover all emitting sectors of the economy or only some sectors?
- Is there a "safety valve"? That is, will the government issue additional GHG emissions allowances to prevent the allowance price from rising above some safety valve level and so avoid the economic disruptions that might accompany high emissions prices?

As demonstrated by the results of this and other studies, the magnitude and timetable for reductions is the biggest issue in terms of overall dollar impact of a cap-and-trade program, but running a close second in importance is whether allowances are auctioned or allocated at no cost, which is the focus of the current study. Auctioning allowances of course would have the same result as allocating allowances at no charge *if* auction revenues were distributed in the same manner as allowances would have been allocated. But such a result is unlikely. The temptation to use auction revenues for social purposes or for reducing government budget deficits will be strong. And if allowances are allocated at no cost, there are still substantial questions about who gets them and how they are used.

For purposes of this study, we assume that retail customers ultimately receive the value of any allowances that are allocated at no cost or of any allowance auction revenues that are recycled. To the extent that this assumption is not realized, the actual results under any allocation scenario will be similar to the results of the full auction with no recycling of revenues, with potentially severe impacts on consumers.

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[1] Offsets reduce greenhouse gasses by means that are generally unrelated to the buyer's business. For example, an electric utility could offset some of its own emissions by investing in reforestation (which absorbs GHGs) by

3. METHODOLOGY

This analysis uses the following units of measurement. First, although some studies measure GHG emissions in short tons (2000 pounds, which is the U.S. unit of measurement) while others use metric tons (= 2204.6 pounds), we have chosen to use metric tons and have converted short tons to metric tons when necessary. Second, following common practice in many of the GHG impact studies to date, we have chosen 2005 as the base year of our study, and so express all costs, prices, and rates in 2005 dollars. The Energy Information Administration's assumptions about dollar inflation were used to convert results to 2005 dollars when necessary.

Estimating the rate impacts of national or regional GHG cap-and-trade programs involves the following four major steps:

a. Identify emission reduction scenarios (i.e., what limits are placed on GHG emissions in the federal or regional program to be analyzed).

b. Estimate the allowance prices that are implied by each of the emission reduction scenarios.

c. Define alternative frameworks for the allocation of allowances.

d. Estimate the rate impacts of the different potential allocation schemes for each of the emission reduction scenarios.

We use this four-step process in estimating rate impacts for customers in each state in the study area, for each of the years 2012 through 2030.

As noted above, the estimates are subject to significant uncertainties in the future government-imposed limits on GHG emissions, GHG trading schemes, the allocation of GHG allowances, emissions mitigation costs, the pace at which new technology will become available, and future fuel prices. Because of these uncertainties, we examine the relative impacts of alternative proposals under a range of future conditions, GHG reduction requirements, and allowance auction allocation schemes. Thus, our analysis provides a range of plausible impacts based on a high-price case (stringent emission reductions and accompanying high allowance prices), a low-price case (with less stringent reductions and thus lower allowance prices), and a moderate cost case that will be somewhere in the middle. These three cases are each analyzed in conjunction with alternative allowance auction or allocation scenarios.

In the following sections, we discuss how each of the four steps described above has been applied.

3.1. Identify Emission Reductions Cases

Allowance prices depend upon the GHG reductions required in the chosen scenarios; upon mitigation costs, which depend upon uncertain technological progress; upon fuel prices; and upon the magnitude of load growth. The first step in estimating rate impacts of GHG limitations is therefore to determine the level and timetable of reductions that will be required. The level and timing of reductions is the most crucial information needed in determining how much compliance will cost, which in turn sets the price at which allowances will be traded in a cap-and-trade market.

At the federal level, there have been numerous legislative proposals in Congress for GHG emissions limitations including, for example, Lieberman-Warner[2], the Boxer substitute to Lieberman-Warner[3], Bingaman-Spector[4], Sanders-Boxer[5], and Feinstein-Carper[6]. All of these proposals have different starting points and different trajectories for GHG reduction over time. While most current proposals call for GHG reductions by all sectors of the economy, there are some proposals that suggest reductions only by the electric sector. There is no way to know which of these proposals, if any, will pick up steam and ultimately be enacted by the 111th Congress.

This report looks at three emissions reductions cases: a high-price case (from a customer rate impact standpoint), a low-price case, and a middle-of-the-road or "moderate" case. The allowance prices applicable to these cases were based on three legislative proposals that have received serious consideration and have been the subjects of several economic impact studies. The three legislative proposals are Boxer-Sanders, Bingaman-Spector, and the Boxer substitute to Lieberman-Warner (hereafter "Lieberman-Warner"). Based on a review of analyses performed on the price impacts of these bills, Boxer-Sanders was chosen to represent the high-price case, Lieberman-Warner the moderate price case, and Bingaman-Spector as the low-price case

Figure 1 shows the emissions caps for the three cases.

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[2] S. 2191, *The Climate Security Act*, introduced December 2007.

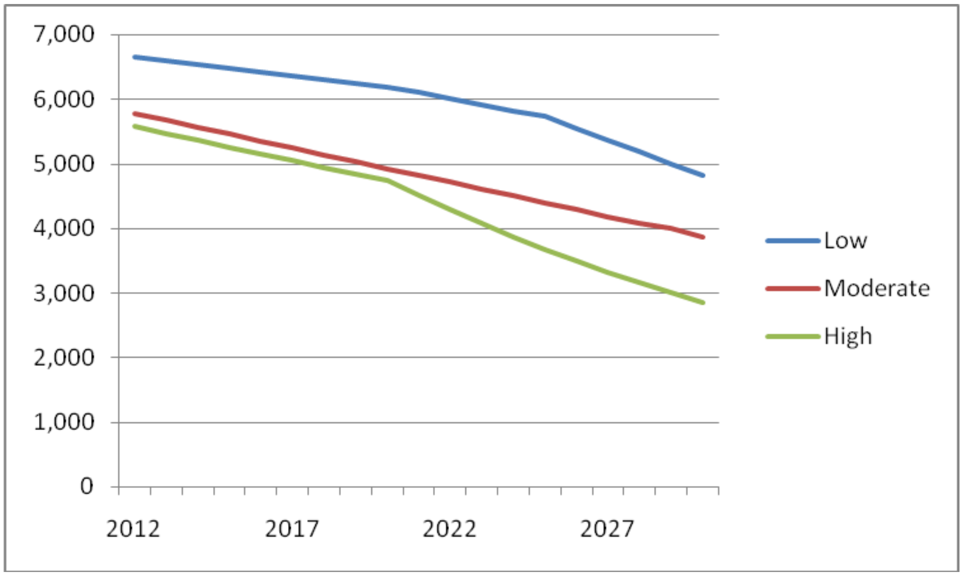
[3] S. 3036, *Substitute Amendment to S. 2192*, Considered by full Senate in June 2008.

[4] S. 1766, *Low Carbon Economy Act*, introduced July 2007.

[5] S. 309, *Global Warming Pollution Reduction Act*, introduced January 2007.

[6] S. 317, *The Electric Utility Cap and Trade Act*, introduced January 2007.

FIGURE 1
EMISSION CAPS FOR THE THREE STUDY CASES
(IN MILLIONS OF METRIC TONS)



3.2. Estimate Allowance Prices

Individual emitters will compare their own costs of reducing GHG emissions with the market price of allowances. If an emitter can buy an allowance for less than the cost of reducing its own emissions, it will be better off buying the allowance. If an emitter can sell an allowance for more than the cost of reducing its own emissions, it will reduce its emissions more than necessary to meet its own emissions targets and thereby be able to sell allowances. The trading process should result in the market price in any period of time tending to equilibrate at the market's current marginal cost of compliance – either by demand reductions, changes in generation used, or deployment of new technologies. If the market as a whole lacks inexpensive compliance options, allowance prices could go very high; but if some emitters have inexpensive compliance options, their emissions reductions can result in low allowance prices. Because of the possibility that compliance costs may be high, some parties advocate a "safety valve" to set a maximum price for allowances: such a safety valve would avoid or mitigate the economic disruptions that can accompany high allowance prices.

Marginal costs of compliance will partly depend upon technological progress: development of new technologies for carbon capture and sequestration, for example, could play a major role in holding down future emissions prices. However, if new technologies to reduce the GHG emissions of electricity production do not become available at sufficiently low cost or are delayed, then marginal costs may be extremely high and rate impacts could exceed those forecast in this study.

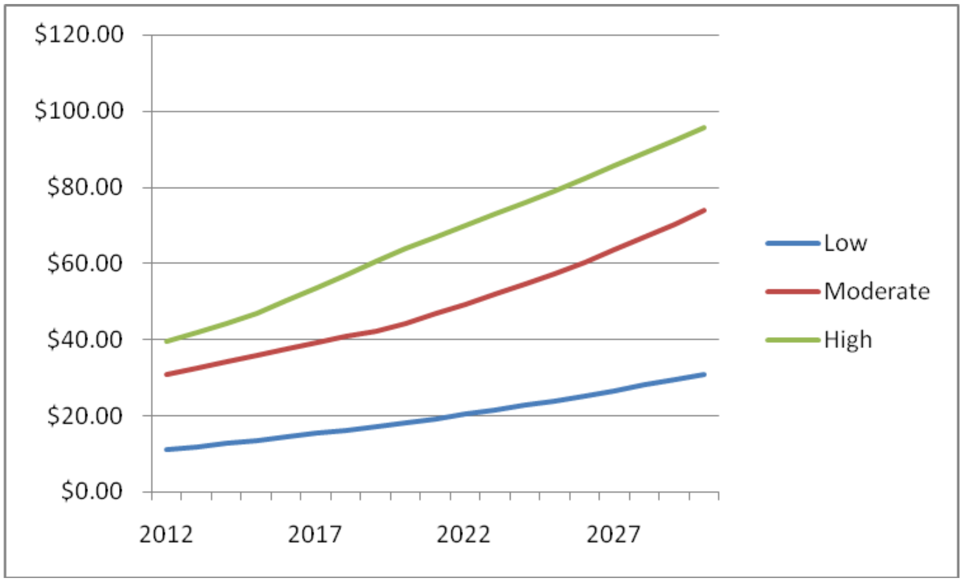
Marginal costs will also partly depend upon the availability of offsets. Offsets allow emitters the ability to pay someone else to reduce emissions or sequester GHGs – possibly anywhere in the world – in lieu of reducing emissions themselves or buying allowances. The availability of offsets will reduce allowance prices if they reduce emitters' compliance costs. For purposes of this study, we only looked at estimated allowance prices resulting from modeling runs where allowed offsets were 15% or less of total GHG reduction requirements.

Each of the emission reduction proposals will have an associated allowance price. In many cases, there may be differing forecasts of prices for the same emissions reduction scheme. For example, there have probably been over a dozen studies done to estimate the allowance prices that would result from Lieberman-Warner, all with somewhat different results. All of these estimates are dependent on input assumptions, including assumptions about future fuel prices and especially technological progress. History has shown that forecasts of these parameters rarely get it right. The possibility of a safety valve will also affect allowance costs. The Bingaman-Spector bill, for example, includes such a safety valve. For purposes of this study, we did not assume that there would be a safety valve in final legislation.

The presence of a national GHG emissions reduction program will likely mean that there will be a single national price for allowances because there will be no significant barriers to trades among entities in different parts of the U.S. Thus, it is not necessary to estimate regional or state-level prices for allowances: the national forecasts of allowance prices will be sufficient. Furthermore, although the allocation of allowances can have major financial impacts on individual persons and firms, it will not affect the *price* of allowances. Rather, prices for allowances will be set by the supply and demand for allowances in any particular time period. The demand for allowances depends on the level of reduction required and the supply depends on the opportunities and technologies for emission reductions – neither of which depend on how allocations are distributed. Thus, once an allowance price is determined, it can be used as the relevant price for all of the studied states under all allocation scenarios.

We did not attempt to forecast allowance prices for our three cases. Rather, we relied on published forecasts made by others. Several organizations, both governmental and non-governmental, have analyzed the impacts of the Warner-Lieberman, Bingaman-Spector, and Sanders-Boxer bills under various assumptions about the future. In choosing the published forecasts that would serve as the basis for our study, we excluded: a) studies that had unrealistic assumptions about the future (e.g., all new generation is nuclear); b) studies wherein more than 15% offsets were allowed; c) studies in which a safety valve affected the final price; and d) studies with prices that were extraordinarily high or low relative to the norm of the other studies. Our selection of studies for this report does not represent an endorsement or rejection of any particular set of assumptions or study results, but it does allow us to derive rate and cost impacts that are consistent with mainstream published studies of the economic impacts of GHG proposals. To develop prices for our three allowance reduction cases, we took a simple average of the pricing results of the remaining studies. Figure 2 below presents the resulting price cases.

FIGURE 2
FORECAST ALLOWANCE PRICES USED IN STUDY
(IN 2005 DOLLARS PER METRIC TON)



Section 3 describes our models and data sources. Numerous such sources were available that relate prices to different levels of required reductions, several being specific to particular legislation and others positing allowance prices as a function of the reduction required, independent of specific proposals.

3.3. Define Alternative Scenarios for Allowance Allocation

In any cap-and-trade regime, there are two basic options for dealing with allowances – they can be auctioned to the highest bidder or simply given ("allocated") to someone at a fixed cost or at no cost. If the number of available allowances is the same in both an auction and an allocation regime, however, then prices will be the same in both systems because price will be set by the same marginal sources of emissions reductions. This identity of prices simplifies the analytic possibilities. For example, if all allowances were allocated to LSEs according to their relative emissions, the resulting distribution of wealth would be equivalent to what it would be if all allowances were auctioned and the auction revenues were then distributed among LSEs according to their relative emissions.[7] In other words, allocating auction revenues to a particular

[7] The reasonableness of this equivalence is subject to a number of quibbles related to financing issues (e.g., it is financially easier to simply receive allowances than to buy them first and get money back later) and differences between willingness to pay and willingness to receive.

combination of parties according to a particular allocation scheme is essentially equivalent to directly allocating allowances to those same parties under the same scheme.

The key differences among allocation scenarios therefore lies not in whether allowances are auctioned or not but in how the market value of the allowances is allocated among parties. Our analysis considers three possibilities for allocating the market value of GHG emissions allowances for the electricity sector:

- The market value can be captured by government, which can use this value to reduce taxes or finance government programs.
- The market value can be returned to customers (via their LSEs) based on each LSE's share of total electric sector emissions.
- The market value can be returned to customers (via their LSEs) based on each LSE's share of total electric sector retail sales to consumers.

We looked at the latter two allocation methods because they are the two primary methods that have been debated for allocating no-cost allowances to LSEs, assuming that government does not capture the value. The choice between these two allocation measures has been controversial. First, auction revenues (or no-cost allowances) could be distributed based on the emissions share of an LSE ("input-based" allocations). In such a case, LSEs with a larger share of emissions in the base year will get a greater number of allowances in the future, while lower-emitting utilities (such as LSEs heavily reliant on nuclear power) would get relatively few allowances. Second, auction revenues (or no-cost allowances) could be distributed based on relative retail sales ("output-based" allocations). In this case, all LSEs would get at least some no-cost allowances, so LSEs with higher retail sales would receive a greater share of allowances than LSEs with lower retail sales, regardless of their past or current emission levels. We do not make a choice for this study between the three alternatives for allocating the value of allowances described above. Instead, we look at various combinations of these alternatives, with the assumption that the values of any auction revenues or no-cost allowances ultimately goes entirely to customers. Thus, we estimate ratepayer impacts under six different scenarios for allowance distribution:

Scenario 1. Auction of allowances with no revenues recycled to LSEs for rate relief.

Scenario 2. Auction of allowances with 50% of revenues recycled to LSEs on the basis of GHG emissions shares.

Scenario 3. Auction of allowances with 50% of revenues recycled to LSEs on the basis of retail load shares.

Scenario 4. No-cost allocation to LSEs based on GHG emissions shares.

Scenario 5. No-cost allocation to LSEs based on retail load shares.

Scenario 6. No-cost allocation of allowances to LSEs, with 50% based on emissions shares and 50% based on retail load shares.

For the emissions scenarios, we use an entity's relative contribution to total electric sector emissions in 2005 (the base year) as the basis for allocations, and for the retail load scenarios, we use an entity's relative share of total electric retail sales in 2005. These ratios are assumed to remain constant for the study period, consistent with most proposals for allocating no-cost allowances. Changing ratios based on changes in relative emissions or retail load could give entities perverse incentives to increase sales or emissions over time.

Note that we did not look at a scenario where 100% of auction revenues are recycled to LSEs, because this would be exactly the same as the fourth, fifth and sixth scenarios – because allowances have the same value whether they are auctioned or allocated at no cost, the benefit to LSEs from returning auction revenues to them is exactly the same as the benefit of giving them allowances to sell (or use) themselves. Table 1 identifies the parties who capture the market value of allowances under each scenario.

TABLE 1
DIVISION OF THE MARKET VALUES OF ALLOWANCES, BY SCENARIO

	Recipient of Value		
Scenario	**Government**	**Customers Based on Emissions**	**Customers Based on Loads**
1	100%		
2	50%	50%	
3	50%		50%
4		100%	
5			100%
6		50%	50%

Some of the legislative proposals use both auctions and no cost allocations in different time periods. Although our scenarios have fixed allocations of allowances, our results can be extended to indicate economic impacts for allocation schemes that change over time. This can be accomplished by mixing the results from the scenarios we used to interpolate results of at least some of the possible mixed schemes. For example, if a proposal has 100% allocation at no cost from 2012 to 2020 and then switches to 100% auctions, looking at the results of Scenarios 4, 5, or 6 for the first period and the results of Scenario 1 for the second period will give an indication of the results for such a mixed approach.

Finally, for each of these six scenarios for allocating allowances, we look at the three cases of allowance prices based on alternative trajectories of required allowance reductions. Thus, a total of 18 cases of ratepayer impacts are analyzed for each state in the study region.

3.4. Estimate Ratepayer Impacts

Our estimates of ratepayer impacts are based upon the following assumptions and procedures.

3.4.1. Assumptions

To make the analytic problem tractable, some simplifying assumptions were made.

First, we assumed that, in cases wherein allowances are allocated, the allocation is based on data from a prior year, and that once a proportional allocation is set, it does not change over time.

Most observers believe that adjusting allocations over time will produce perverse incentives, and thus fixed allocations are usually preferred. For the purposes of this study, we used the most recent year for which a full set of data was available for setting the base year allocation proportions, which is 2005.

Second, we assumed that where allocations are made to LSEs, the full value of the allocation will be used to mitigate ratepayer impacts. We expect that regulators or self-regulated consumer-owned entities will require such a result.

Third, we assumed that the cost of allowances will be reflected in the price for power purchased by LSEs. While some LSEs may have long-term contracts for the purchase of power that prevent the inclusion of allowance costs in the short-term, it is likely that by the time GHG regulation is implemented, these contracts will have substantially expired and been replaced by contracts somehow reflecting allowance costs. Thus, we assume that whatever impacts the seller faces due to GHG regulation will be reflected in wholesale power prices paid by the LSE. We also assume that any GHG reduction program covers all emitting sectors, and that allocation of allowances to the electric sector will be 40% of total allowances available in any year, given that the electric sector produced 40% of total GHG emissions in the nation in the selected base year of 2005.[8]

3.4.2. Generators' Marginal Costs

In principle, a generator's marginal costs will depend upon its carbon intensity – that is, the quantity of CO_2 it emits per MWh generated. In most scenarios, GHG emissions restrictions raise each generator's marginal cost by the price of allowances times its carbon intensity. In scenarios wherein emissions serve as the basis for allowance allocations or for auction revenue recycling, GHG emissions restrictions raise each generator's marginal cost by: a) the price of allowances; times b) its carbon intensity net of the allowances allocated according to the carbon intensity.

Because different generators have different carbon intensities, the dispatch order among different generation technologies could change as a result of GHG emissions allowance requirements. For example, because the carbon intensity of coal-fired generation is nearly double that of gas-fired generation, it is possible that their relative dispatch could change. In organized markets, the impacts of allowance requirements on marginal costs will be directly reflected in electricity offer prices, which could change generation dispatch, the identities of marginal generators, and the market prices of electricity. In traditional markets, the impacts of allowance requirements on marginal costs will also change the least-cost dispatch of generation. Thus, although market structure affects the ways that costs impact customer prices, it should have little or no impact on how costs impact generation dispatch.

To determine whether dispatch might change as a result of GHG emissions limits, we examined the allowance prices at which gas-fired generation, including allowance costs, becomes cheaper than existing coal-fired generation and cleaner new coal generation.. Based on our analyses, gas generation only became cheaper than coal at high allowance prices that are not reached until very

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[8] This is consistent with U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006*, Report #430-R-08-005, April 2008.

late in the study period. Thus, we believe it reasonable to treat dispatch as fixed for the study period, and that more accurate treatment of dispatch would have little effect on our results.

3.4.3. Emissions of Each LSE

For an LSE that produces just enough power to meet its retail needs, it would be relatively straightforward to determine what emissions are associated with the utility's sales to its retail load. Such a utility would only need to look at the emissions of the generation that was dispatched to serve retail load in the time period of interest.

In reality, of course, LSEs virtually always generate either more power or less power than is required to serve their own loads. This makes the calculation of emissions a bit more difficult.

LSEs that generate more power than required to meet their own needs are net sellers. For such LSEs, the emissions associated with the LSE's own retail load equals a fraction of the emissions of its own generation. We assume that this fraction is the ratio of its retail sales to its total generation. In mathematical terms:

$$Emissions_{J,Y} \quad = \quad GenerationEmissions_{J,Y} * \frac{MWh\,Retail\,Sales_{J,Y}}{MWh\,Generated_{J,Y}}$$

where $Emissions_{J,Y}$ is the emissions ascribed to LSE J in year Y, $Generation\ Emissions_{J,Y}$ is the emissions of J's generation in Y, $MWh\ Retail\ Sales_{J,Y}$ is the volume of retail sales by J in Y, and $MWh\ Generated_{J,Y}$ is the total amount of energy generated by J in Y.

LSEs that generate less power than required to meet their own needs are net buyers. For such LSEs, the calculation of the emissions attributable to their loads is made difficult by the fact that the GHG content of the power being purchased cannot be precisely determined in most cases. Thus, some way of estimating the carbon content of the wholesale energy purchased by net buyers must be developed. There are several ways of doing so. For example, one could look at the GHG emission factors of every seller from whom the LSE is buying power. As a simpler alternative, however, one could assume that the LSE is buying power that results in emissions somewhere around the average emissions factor for its local geographic area (e.g., its control area, state, or region). This alternative is reasonable because the designers of cap-and-trade programs are not likely to embrace schemes that require looking at purchases and sales of all LSEs in the country.

For purposes of this study, we therefore use state average emission intensities for wholesale purchases by the LSEs located within a state. Thus, for each LSE that is a net buyer, the emissions associated with its retail load equals the emissions of its own generation plus the state-average emissions associated with its purchases. In mathematical terms:

$$Emissions_{J,Y} \quad = \quad GenerationEmissions_{J,Y} + (MWh\,Retail\,Sales_{J,Y} - MWh\,Generated_{J,Y})\frac{GenerationEmissions_{S,Y}}{MWh\,Generated_{S,Y}}$$

where $Generation\ Emissions_{S,Y}$ is the emissions in Y of the whole generation fleet of the state S in which the LSE is located in year Y and $MWh\ Generated_{S,Y}$ is the total amount of energy generated in state S in year Y. In the extreme case of LSEs that generate none of their own power, the emissions associated with the LSE's retail load would equal the state-average emissions associated with its purchases. In such a case, the preceding equation simplifies to the following:

$$Emissions_{J,Y} \quad = \quad MWh\,Retail\,Sales_{J,Y} * \frac{GenerationEmissions_{S,Y}}{MWh\,Generated_{S,Y}}$$

3.4.4. Ratepayer Impacts

We estimate ratepayer impacts for a variety of auction and allocation approaches. For all scenarios, the net costs to the LSE of a GHG cap-and-trade program will equal the forecasted allowance price times its emissions, minus the value of the allowances that it is allocated:

$$Net\ Cost\ Impact_{J,Y} \quad = \quad (Emissions_{J,Y} * Allowance\,\mathrm{Pr}ice_{Y}) - (Value\,of\ \ Allowances_{J,Y})$$

For all scenarios, rate impacts are determined by dividing the net cost impacts of the GHG reduction case and scenario by the quantity of retail sales:

$$Rate\ impact_{J,Y} = \frac{Net\ Cost\ impact_{J,Y}}{\mathrm{Re}tail\ Sales_{J,Y}}$$

For all scenarios, the percentage rate increases over the 2005 base year are calculated by comparing the rate impact to 2005 rates:

$$\%\ Rate\ Increase_{J,Y} = \frac{Rate\ impact_{J,Y}}{2005\,\mathrm{Re}tail\ Rate_{J}}$$

The scenarios therefore differ from one another only in their differing values of allowances.

Scenario 1. Auctions with No Revenue Recycling

In this scenario, no allowances are allocated, so the value of allowances to the LSE is zero:

$$Value\,of\ \ Allowances_{J,Y} \quad = \quad 0$$

Scenario 2. Auctions with 50% Recycling Based on Emissions

When allowances are allocated or auction revenues are recycled to LSEs based on emissions, the allowances or revenues received by any LSE will be proportional to its emissions relative to total electric sector emissions. With 50% recycling, the factor 0.5 appears in the calculation, as follows:

$$Value\,of\ \ Allowances_{J,Y} = \quad (0.5)(Allowances_{ES,Y} * Allowance\,\mathrm{Pr}ice_{Y}) * \frac{Emissions_{J,2005}}{Emissions_{ES,2005}}$$

where $Allowances_{ES,Y}$ is the total allowances available for the electric sector in year Y and $Emissions_{ES,2005}$ is total electric sector emissions in the base year, 2005.

Scenario 3. Auctions with 50% Revenue Recycling Based on Load Share

When allowances are allocated or auction revenues are recycled back to LSEs based on their relative retail sales, the allowances or revenues received by any LSE will be proportional to its retail sales relative to total electric sector retail sales. With 50% recycling, the factor 0.5 appears in the calculation, as follows:

$$Value\ of\ Allowances_{J,Y} = (0.5)(Allowances_{ES,Y} * Allowance\ Price_{Y}) * \frac{Retail\ Sales_{J,2005}}{Retail\ Sales_{ES,2005}}$$

where $Retail\ Sales_{ES,2005}$ is the total electric sector retail sales in the base year, 2005.

Scenario 4. Allocations to LSEs Based on Emissions

When allowances are allocated or auction revenues are recycled to LSEs based on emissions, the value of allowances received by any LSE will be as expressed for scenario 2, without the 0.5 factor:

$$Value\ of\ Allowances_{J,Y} = (Allowances_{ES,Y} * Allowance\ Price_{Y}) * \frac{Emissions_{J,2005}}{Emissions_{ES,2005}}$$

Scenario 5. Allocations to LSEs Based on Load

When allowances are allocated or auction revenues are recycled to LSEs based on retail load, the value of allowances or revenues received by any LSE will be as expressed for scenario 3, without the 0.5 factor:

$$Value\ of\ Allowances_{J,Y} = (Allowances_{ES,Y} * Allowance\ Price_{Y}) * \frac{Retail\ Sales_{J,2005}}{Retail\ Sales_{ES,2005}}$$

Scenario 6. Allocations to LSEs Based on a Combination of Load and Emissions

In this case, the value of allowances will be the sum of the values shown for scenarios 2 and 3:

$$Value\ of\ Allowances_{J,Y} = (0.5) * (Allowances_{ES,Y} * Allowance\ Price_{Y}) * \left(\frac{Emissions_{J,2005}}{Emissions_{ES,2005}} + \frac{Retail\ Sales_{J,2005}}{Retail\ Sales_{ES,2005}} \right)$$

4. DATA

This section describes the data that we used in our analysis.

4.1. Emission Reduction Cases

The overall emission caps in effect (and thus the number of allowances available) under the three cases (low, moderate and high) were derived directly from the legislation associated with each case. They are the Bingaman-Spector bill (S. 1766), the Lieberman-Warner Bill (S. 3036), and the Sanders-Boxer bill (S. 309). Bingaman-Spector and Lieberman-Warner specify the yearly emission caps, while Sanders-Boxer specifies only a starting and ending point. For Sanders-Boxer, we assumed that the cap would move linearly between these two points to get the annual emissions caps.

4.2. Allowance Prices

As discussed in Section 2.2, we did not attempt to forecast allowance prices, but rather relied on existing studies that in turn analyzed the emission cap effects in each of our three cases. In choosing the published forecasts that would serve as the basis for our study, we excluded: a) studies that had unrealistic assumptions about the future (e.g., all new generation is nuclear); studies wherein more than 15% offsets were allowed; c) studies in which a safety valve affected the final price; and d) studies with prices that were extraordinarily high or low relative to the norm of the other studies. Each of these existing studies ran their models multiple times to look at allowance prices under alternative views of the future. Instead of trying to normalize these studies around their assumptions or place a probability on their likelihood, we took a simple average of the allowance prices that were estimated in each study to come up with our estimated value of allowance prices. In some of the studies used to obtain our estimate, results were specified in five-year increments. In those cases, we assumed that there would be a linear increase between each five year data point. The following are the data sources used for each of our cases. Appendix B lists the specific modeling runs that were used to obtain an average that was used as the basis for the forecasts in this study.

4.2.1. Low Case (Bingaman-Spector)

The price forecasts for the Low Case were derived from two sources: the Energy Information Administration AEO (Annual Energy Outlook) NEMS (National Energy Modeling System) model and the EPA ADAGE (Applied Dynamic Analysis of the Global Economy) model. The EIA modeling results are contained in a special report analyzing the bill.[9] The EPA ADAGE model results were taken from another EPA special report.[10]

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[9] U.S. Energy Information Administration, *Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007*, Washington, D.C., January 2008 at http://www.eia.doe.gov/oiaf/1605/climate.html.

[10] U.S. Environmental Protection Agency, *Part 2 of The United States Environmental Protection Agency's Analysis of Senate Bill S.1766 in the 110th Congress, the Low Carbon Economy Act of 2007*, Washington, D.C., January 2008 at http://www.epa.gov/climatechange/economics/pdfs/DataAnnex.zip.

4.2.2. Moderate Case (Lieberman-Warner)

The price forecasts for the Moderate Case were derived from three sources: the Energy Information Administration AEO (Annual Energy Outlook) NEMS (National Energy Modeling System) model, the EPA ADAGE (Applied Dynamic Analysis of the Global Economy) model, and the MIT Emissions Prediction and Policy Analysis Model (EPPM). The EIA AEO Modeling Results came from a special report.[11] The EPA ADAGE results were from another special report.[12] And the MIT EPPM results are from their report.[13] The MIT report was drafted before the Lieberman-Warner proposal was introduced, so it instead analyzes the Lieberman-McCain Bill introduced in 2007, which is very similar to and was used as a proxy for Lieberman-Warner in this study.

4.2.3. High Case (Sanders-Boxer)

There have been very few analyses conducted of the Sanders-Boxer legislation. Neither EIA nor EPA has examined it directly. MIT did not examine the Sanders-Boxer bill, but did have a series of model runs that require a 167 bmt (billion metric tons) reduction in GHG by 2050, which has almost the same reduction trajectory as the Sanders-Boxer bill, so the MIT 167 bmt scenario from the MIT Report[14] was used in this study.

4.3. State Load, Generation, Emissions, Wholesale Purchases, & Wholesale Sales

For the Base Year (2005) data, the Energy Information Administration's *Electric Power Annual* provides state data on retail load and generation. For this study, we used the State Data Tables.[15] The base year wholesale purchases and wholesale sales data were estimated based on generation and retail sales.[16] For 2005 emissions by state, we relied on EPA's eGRID2007 analysis.[17] For 2005 average retail prices, we again used EIA's *Electric Power Annual*.[18]

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[11] U.S. Energy Information Administration, *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007*, Washington D.C.; April 2008 at http://www.eia.doe.gov/oiaf/1605/climate.html.

[12] U.S. Environmental Protection Agency, *The United States Environmental Protection Agency's Analysis of Senate Bill S.2191 in the 110th Congress, the Lieberman-Warner Climate Security Act of 2008*, Washington, D.C., January 2008 at http://www.epa.gov/climatechange/economics/economicanalyses.html#s2191.

[13] Paltsev *et. al*., *Assessment of U.S. Cap and Trade Proposals*, MIT Joint Program on the Science and Policy of Global Change, Report 146, Cambridge, MA; 2007.

[14] *Ibid*.

[15] U.S. Energy Information Administration, *Electric Power Annual 2007 - State Data Tables*, Washington, D.C., January 26, 2009, at www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html.

[16] We did not account for transmission and distribution losses in analyzing the state data.

[17] U.S. Environmental Protection Agency, *eGRID2007 Version 1.1*, Washington, D.C., January 2009 at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

[18] U.S. Energy Information Administration, *Electric Power Annual 2007; 1990 - 2007 Average Price by State by Provider*, Washington, D.C. January 2009 at www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html.

For forecasts to 2030 of state retail load, generation, and emissions, we did not have state level forecasts to rely on, but in its *Annual Energy Outlook* the EIA does make forecasts at the Reliability Council level. Thus, for purposes of this study, we assumed that state retail load, generation, and emissions and wholesale purchases would grow at the same rate as the reliability council in which it is located. For states that have more than one reliability council within their borders, we took an average of the growth rates for those reliability councils. The source of the forecast data for retail load, generation and emissions at the Reliability Council level was the *Annual Energy Outlook* for 2009.[19] Wholesale sales were estimated based on the other data.

5. RESULTS

In this section, we discuss the study results for the seven states in the study area – Indiana, Iowa, Minnesota, Missouri, North Dakota, South Dakota, and Wisconsin. For each of these entities, we summarize GHG limitation impacts on total costs, rates, and rate increases (relative to 2005) for the study period for each of the three cases and six scenarios.

5.1. Indiana

The net cost of the six different methods for allocating either auction revenues or allowances under the three alternative cap-and-trade emission restriction cases are shown in Table 2.[20] The costs presented in this and subsequent tables are net of any recycled revenues or the value of allocated allowances.

As would be expected, Scenario 1, wherein all allowances are auctioned and there is no revenue recycling to LSEs, has the highest costs to electricity customers in every case. This adverse result for Scenario 1 is shared by all states. If 50% of auction revenues are recycled, there is not a significant difference whether they are recycled based on emissions (Scenario 2) or retail load (Scenario 3). But if allowances are allocated at no cost, Indiana ratepayers do considerably better if they are allocated based on emissions (Scenario 4) rather than retail load (Scenario 5). This is not unexpected because Indiana relies heavily on coal, so it will receive a higher proportion of allowances when the allocations are based on emissions rather than load. As required emissions reductions increase (over time, and moving from the low to the moderate to the high cases,) the differences between emission-based and load-based allocations are reduced.

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[19] U.S. Energy Information Administration, *Supplemental Tables to Annual Energy Outlook 2009*. Washington, D.C., December 2008, at http://www.eia.doe.gov/oiaf/aeo/supplement/sup_elec.xls.

[20] As a reminder, the low case is Bingaman-Spector, the moderate case is Lieberman Warner, the high case is Sanders-Boxer, and the six scenarios are:

Scenario 1. Auction of allowances with no revenues recycled to LSEs for rate relief.

Scenario 2. Auction of allowances with 50% of revenues recycled to LSEs on the basis of GHG emissions shares.

Scenario 3. Auction of allowances with 50% of revenues recycled to LSEs on the basis of retail load shares.

Scenario 4. No-cost allocation to LSEs based on GHG emissions shares.

Scenario 5. No-cost allocation to LSEs based on retail load shares.

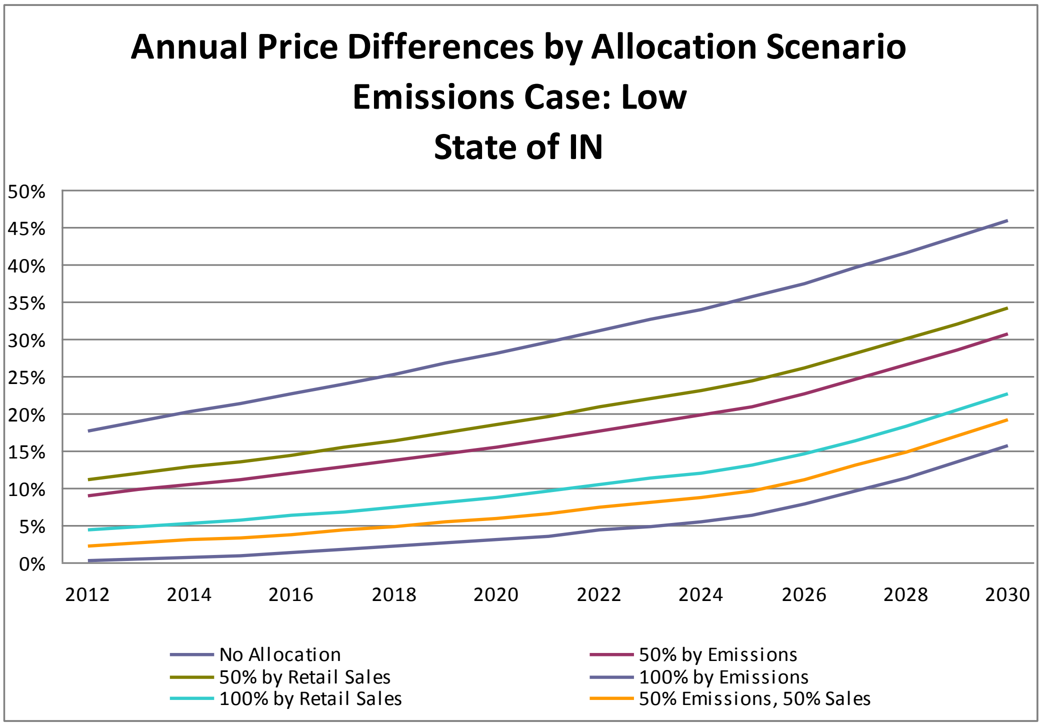
Scenario 6. No-cost allocation of allowances to LSEs, with 50% based on emissions shares and 50% based on retail load shares.

TABLE 2
ANNUAL NET COST TO INDIANA RATEPAYERS
(IN THOUSANDS OF 2005 DOLLARS)

	2012	*2015*	*2020*	*2025*	*2030*
Low					
Scenario 1	$1,148,283	$1,404,597	$1,915,866	$2,524,706	$3,406,759
Scenario 2	$581,359	$731,568	$1,059,749	$1,484,856	$2,281,582
Scenario 3	$712,016	$886,678	$1,257,055	$1,724,506	$2,540,897
Scenario 4	$14,435	$58,538	$203,633	$445,006	$1,156,404
Scenario 5	$275,748	$368,759	$598,245	$924,306	$1,675,034
Scenario 6	$145,092	$213,649	$400,939	$684,656	$1,415,719
Moderate					
Scenario 1	$3,143,153	$3,672,480	$4,647,907	$6,019,442	$8,164,240
Scenario 2	$1,795,925	$2,189,473	$2,995,212	$4,119,797	$6,004,379
Scenario 3	$2,106,415	$2,531,256	$3,376,102	$4,557,601	$6,502,153
Scenario 4	$448,696	$706,465	$1,342,516	$2,220,153	$3,844,518
Scenario 5	$1,069,677	$1,390,031	$2,104,297	$3,095,760	$4,840,067
Scenario 6	$759,186	$1,048,248	$1,723,407	$2,657,956	$4,342,293
High					
Scenario 1	$4,014,370	$4,766,806	$6,685,420	$8,326,269	$10,574,650
Scenario 2	$2,349,136	$2,911,042	$4,389,818	$6,125,198	$8,511,285
Scenario 3	$2,732,916	$3,338,733	$4,918,876	$6,632,470	$8,986,820
Scenario 4	$683,902	$1,055,278	$2,094,216	$3,924,127	$6,447,919
Scenario 5	$1,451,462	$1,910,659	$3,152,333	$4,938,671	$7,398,990
Scenario 6	$1,067,682	$1,482,968	$2,623,275	$4,431,399	$6,923,455

In Figure 3 through Figure 5, we present the percentage rate increases for Indiana Ratepayers (compared to 2005) of the six scenarios for allowance auctions or allocations under the three reduction cases. For 2030, the rate increases range approximately from 15% to 45% in the Low Case, 50% to 110% in the Moderate Case, and 85% to 140% in the High Case.

FIGURE 3[21]



[21] In this and subsequent figures, "Annual Price Differences" are the percentage increases in retail rates due to GHG limits relative to the Base Year, 2005.

FIGURE 4

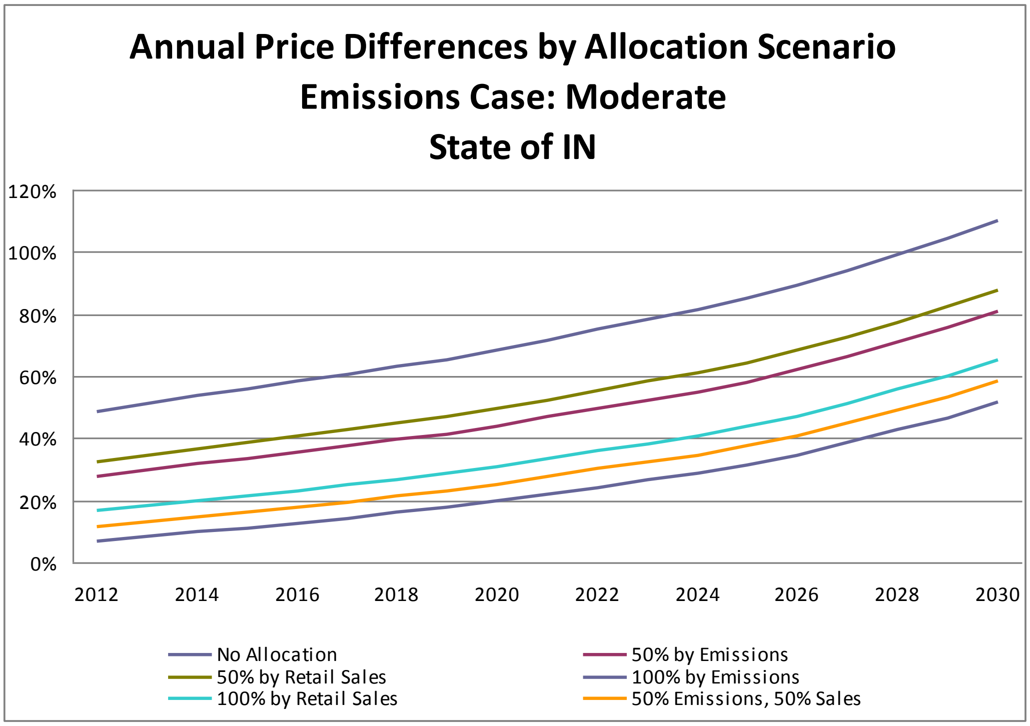
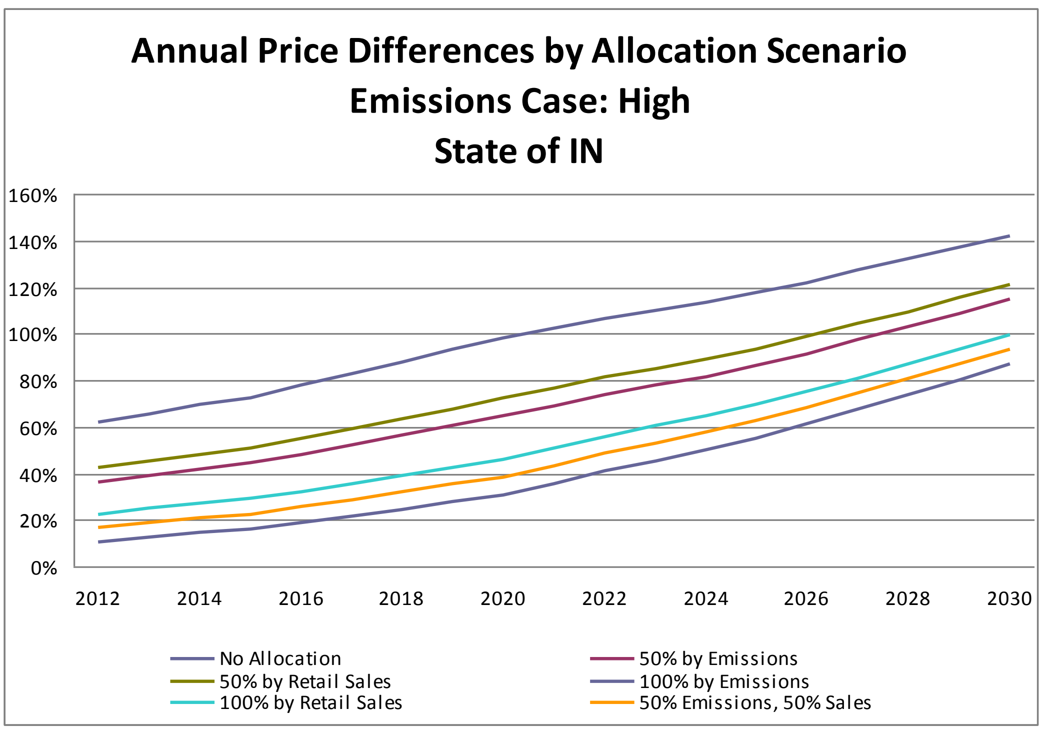


FIGURE 5



5.2. Iowa

The net cost of the six different methods for allocating either auction revenues or allowances for Iowa ratepayers under the three alternative cap-and-trade emission restriction cases are shown in Table 3. The results for Iowa are generally similar to those for Indiana. Again, Scenario 1, wherein all allowances are auctioned and there is no recycling to load-serving entities, is the most costly scenario in each case. If 50% of auction revenues are recycled, there is not a significant difference whether they are recycled based on emissions or retail load, but if allowances are allocated at no cost, Iowa ratepayers also do considerably better if they are allocated based on emissions rather than retail load.

TABLE 3
ANNUAL NET COST TO IOWA RATEPAYERS
(IN THOUSANDS OF 2005 DOLLARS)

	2012	*2015*	*2020*	*2025*	*2030*
Low					
Scenario 1	$409,739	$503,238	$671,186	$897,639	$1,229,186
Scenario 2	$202,657	$257,398	$358,470	$517,809	$818,188
Scenario 3	$234,670	$295,403	$406,813	$576,529	$881,725
Scenario 4	-$4,426	$11,558	$45,753	$137,980	$407,190
Scenario 5	$59,602	$87,568	$142,441	$255,418	$534,265
Scenario 6	$27,588	$49,563	$94,097	$196,699	$470,728
Moderate					
Scenario 1	$1,121,564	$1,315,773	$1,628,304	$2,140,165	$2,945,722
Scenario 2	$629,457	$774,070	$1,024,618	$1,446,275	$2,156,782
Scenario 3	$705,534	$857,813	$1,117,944	$1,553,546	$2,278,747
Scenario 4	$137,350	$232,366	$420,932	$752,385	$1,367,842
Scenario 5	$289,503	$399,853	$607,583	$966,927	$1,611,771
Scenario 6	$213,427	$316,110	$514,257	$859,656	$1,489,806
High					
Scenario 1	$1,432,439	$1,707,847	$2,342,107	$2,960,340	$3,815,417
Scenario 2	$824,173	$1,029,986	$1,503,584	$2,156,347	$3,061,724
Scenario 3	$918,207	$1,134,778	$1,633,214	$2,280,638	$3,178,240
Scenario 4	$215,907	$352,124	$665,061	$1,352,353	$2,308,031
Scenario 5	$403,974	$561,710	$924,321	$1,600,937	$2,541,063
Scenario 6	$309,941	$456,917	$794,691	$1,476,645	$2,424,547

Figure 6 through Figure 8 show the percent rate increases (relative to 2005) for Iowa ratepayers for each of the three emission reduction cases and the six allocation scenarios within each case. The relationships are fairly linear through time. For 2030, the rate increases range from about 12% to 35% in the Low Case, 40% to 85% in the Moderate Case, and 65% to 110% in the High

Case. These results suggest a very high variation between auctions and allowance allocations at no cost.

FIGURE 6

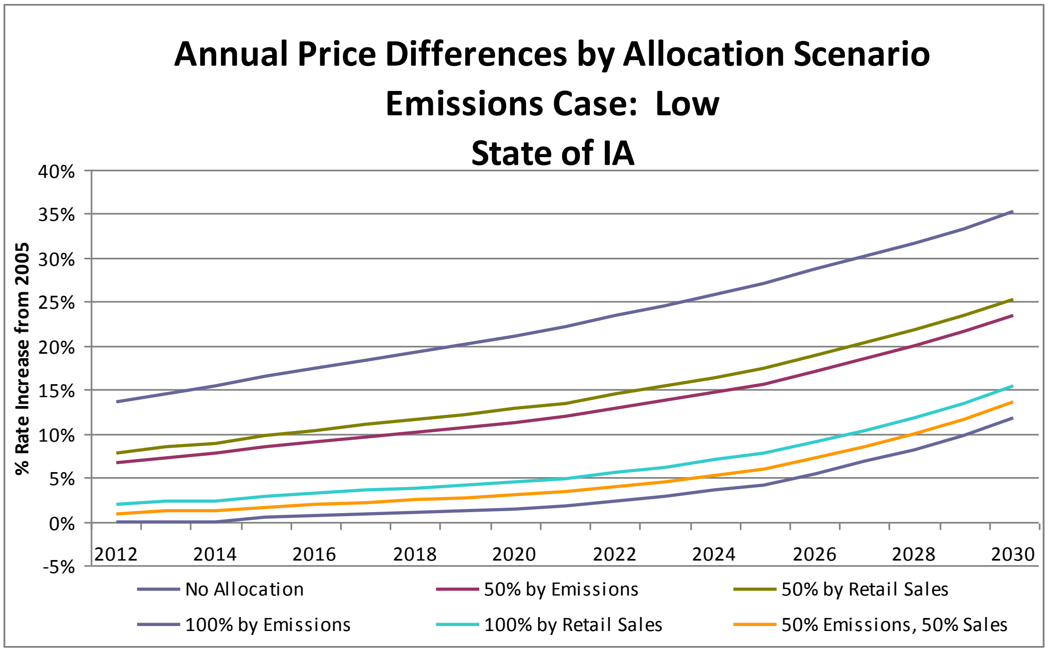


FIGURE 7

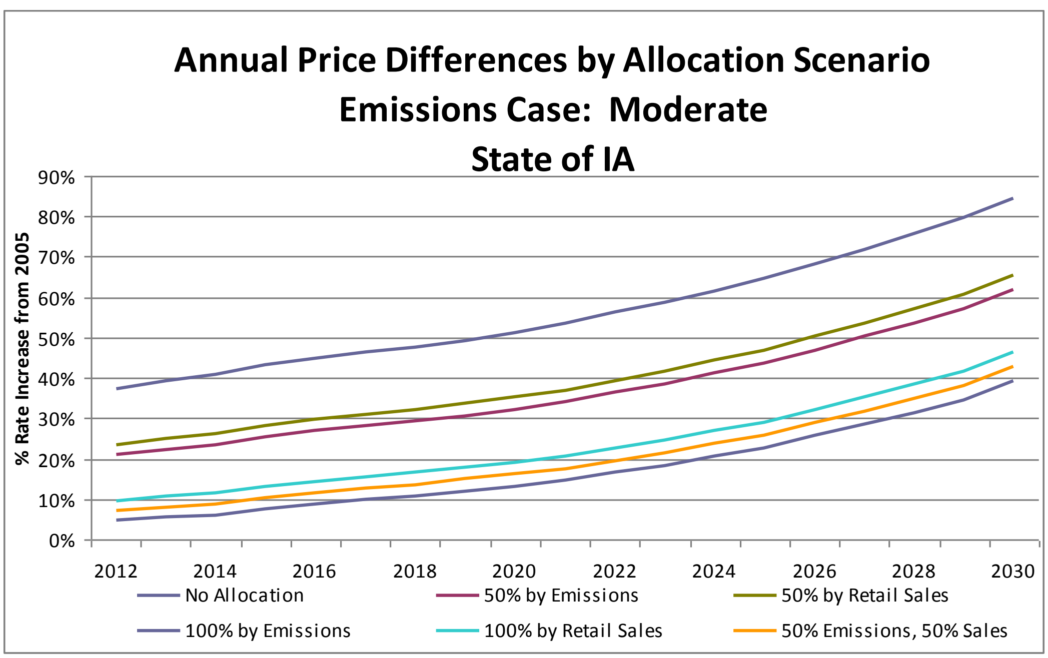
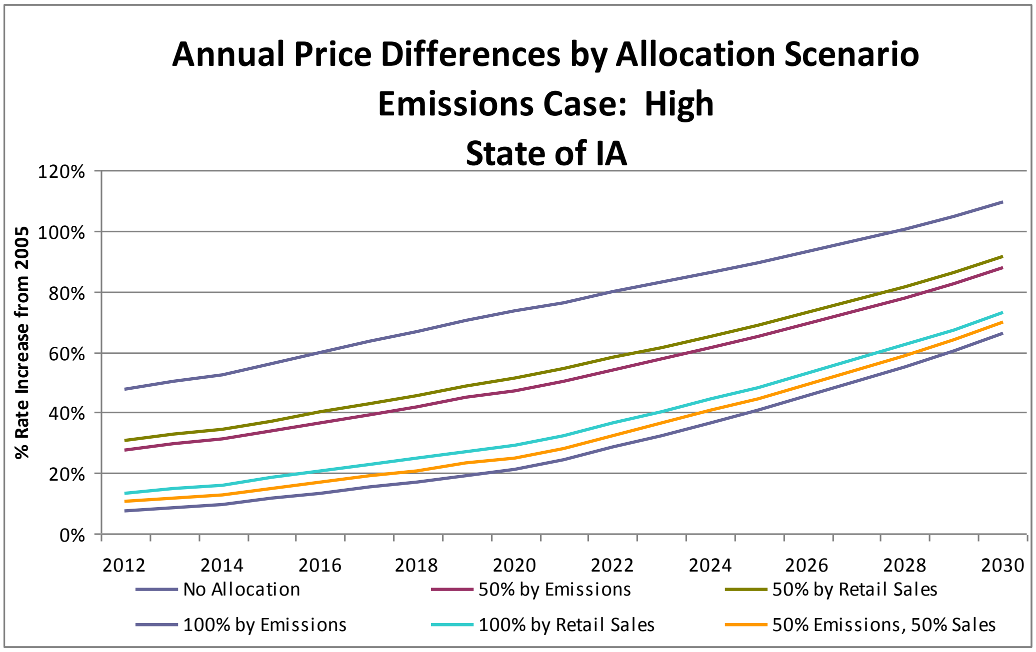


FIGURE 8



5.3. Minnesota

Table 4 shows the net cost impacts to Minnesota ratepayers under the three reduction cases and six allocation scenarios. If 50% of auction revenues are recycled, then there is very little difference whether they are recycled based on emissions or retail load. And in Minnesota's case, there also is only a small difference between load-based and emissions-based no–cost allocations.

TABLE 4
ANNUAL NET COST TO MINNESOTA RATEPAYERS
(IN THOUSANDS OF 2005 DOLLARS)

	2012	*2015*	*2020*	*2025*	*2030*
Low					
Scenario 1	$522,787	$643,063	$864,719	$1,164,036	$1,593,261
Scenario 2	$260,898	$332,159	$469,238	$683,680	$1,073,488
Scenario 3	$252,470	$322,154	$456,511	$668,222	$1,056,762
Scenario 4	-$992	$21,255	$73,758	$203,324	$553,716
Scenario 5	-$17,847	$1,245	$48,304	$172,408	$520,262
Scenario 6	-$9,419	$11,250	$61,031	$187,866	$536,989
Moderate					
Scenario 1	$1,431,004	$1,681,363	$2,097,816	$2,775,312	$3,818,223
Scenario 2	$808,656	$996,292	$1,334,357	$1,897,776	$2,820,481
Scenario 3	$788,628	$974,246	$1,309,789	$1,869,537	$2,788,373
Scenario 4	$186,307	$311,221	$570,899	$1,020,241	$1,822,739
Scenario 5	$146,252	$267,129	$521,762	$963,762	$1,758,523
Scenario 6	$166,280	$289,175	$546,331	$992,001	$1,790,631
High					
Scenario 1	$1,827,649	$2,182,376	$3,017,439	$3,838,893	$4,945,515
Scenario 2	$1,058,399	$1,325,111	$1,956,992	$2,822,114	$3,992,349
Scenario 3	$1,033,644	$1,297,524	$1,922,867	$2,789,394	$3,961,675
Scenario 4	$289,148	$467,846	$896,545	$1,805,336	$3,039,182
Scenario 5	$239,639	$412,671	$828,294	$1,739,895	$2,977,836
Scenario 6	$264,394	$440,258	$862,419	$1,772,615	$3,008,509

Figure 9 through Figure 11 show the percent rate increases (relative to 2005) for Minnesota ratepayers for each of the three emission reduction cases and the six allocation scenarios within each case. For 2030, the rate increases range from about 10% to 30% in the Low Case, 35% to 70% in the Moderate Case, and 60% to 90% in the High Case. The percentage rate impacts also confirm that Minnesota appears to be indifferent between load-based and emissions-based auction recycling and no-cost allocations. But there is a great difference between auctions and no-cost allocations for Minnesota's power consumers.

FIGURE 9

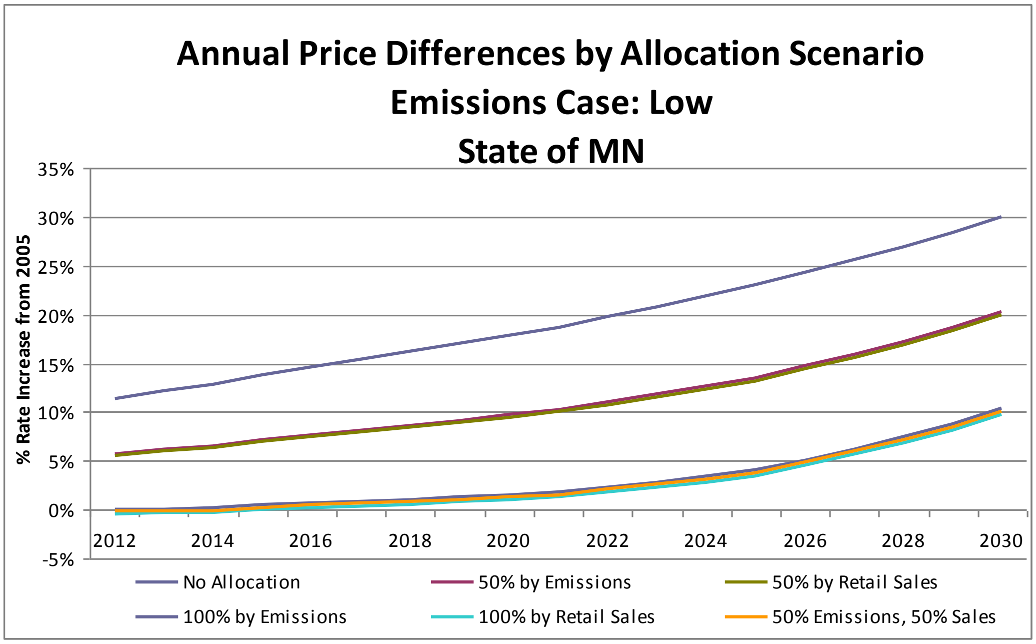


FIGURE 10

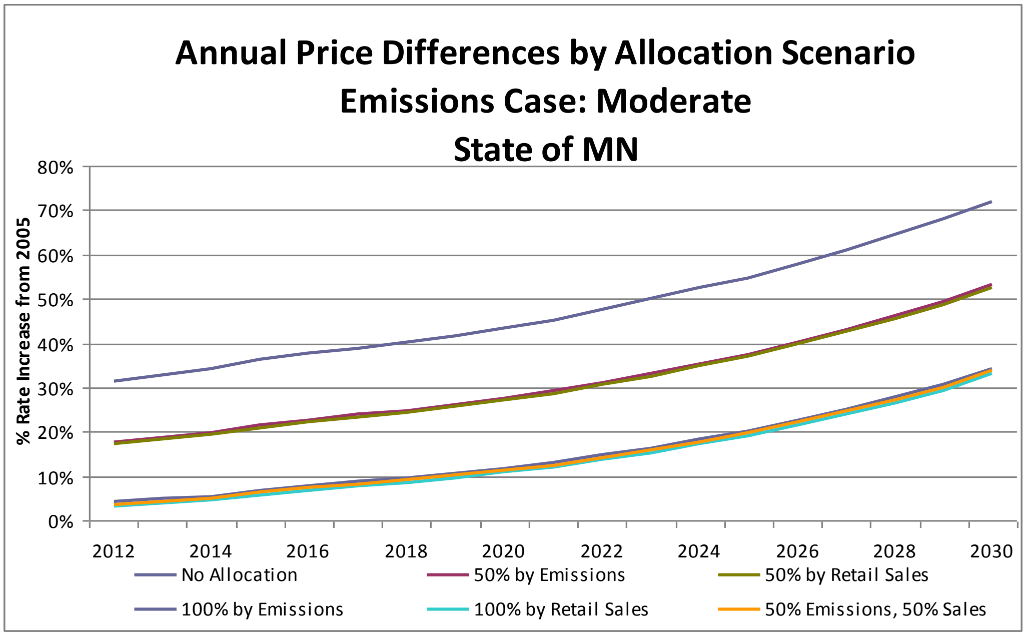
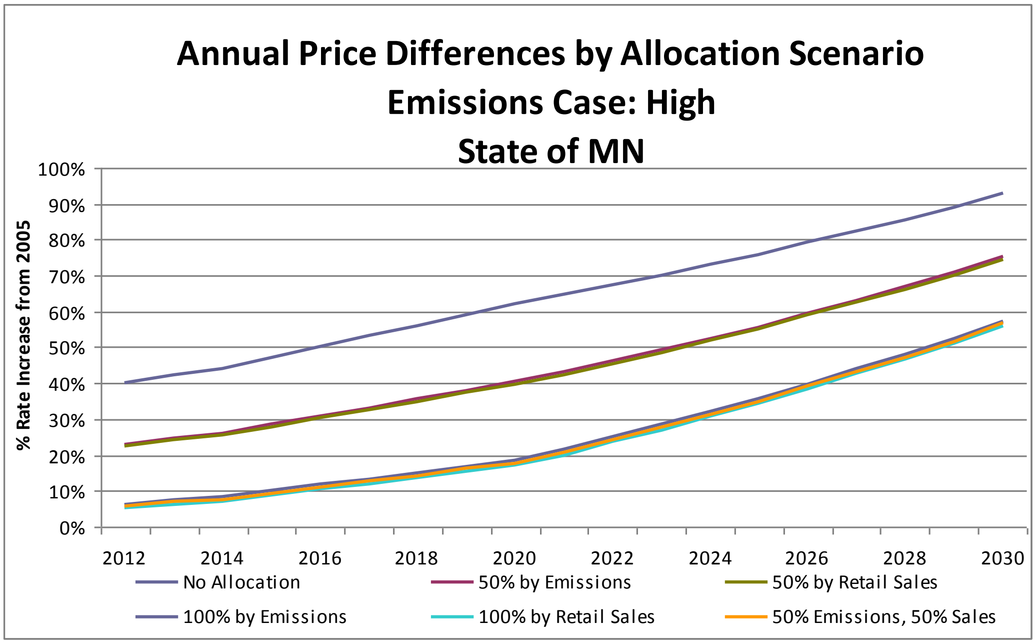


FIGURE 11



5.4. Missouri

Table 5 shows the net cost impacts to Missouri ratepayers under the three reduction cases and six allocation scenarios. Missouri ratepayers actually see a rate decrease through 2020 for the Low Case of emissions reduction and the allocation scenario under which LSEs are given allowances based on emissions. There also is a relatively small difference between load-based and emissions-based auctions and no-cost allocations, particularly in the later years. And again in the later years in each of the cases, Missouri customers also see less of an impact between auctions and no-cost allocations than in some other states.

TABLE 5
ANNUAL NET COST TO MISSOURI RATEPAYERS
(IN THOUSANDS OF 2005 DOLLARS)

	2012	*2015*	*2020*	*2025*	*2030*
Low					
Scenario 1	$733,887	$887,948	$1,125,177	$1,462,692	$2,009,020
Scenario 2	$352,614	$435,317	$549,415	$763,363	$1,252,307
Scenario 3	$402,474	$494,508	$624,708	$854,815	$1,351,263
Scenario 4	-$28,658	-$17,314	-$26,347	$64,035	$495,593
Scenario 5	$71,060	$101,068	$124,239	$246,939	$693,506
Scenario 6	$21,201	$41,877	$48,946	$155,487	$594,549
Moderate					
Scenario 1	$2,008,841	$2,321,643	$2,729,691	$3,487,372	$4,814,582
Scenario 2	$1,102,792	$1,324,278	$1,618,206	$2,209,807	$3,362,015
Scenario 3	$1,221,277	$1,454,705	$1,763,556	$2,376,876	$3,551,969
Scenario 4	$196,743	$326,914	$506,722	$932,243	$1,909,449
Scenario 5	$433,713	$587,767	$797,422	$1,266,380	$2,289,356
Scenario 6	$315,228	$457,340	$652,072	$1,099,311	$2,099,402
High					
Scenario 1	$2,565,650	$3,013,446	$3,926,310	$4,823,835	$6,236,040
Scenario 2	$1,445,733	$1,765,392	$2,382,454	$3,343,553	$4,848,369
Scenario 3	$1,592,186	$1,928,601	$2,584,345	$3,537,131	$5,029,836
Scenario 4	$325,817	$517,339	$838,597	$1,863,271	$3,460,698
Scenario 5	$618,722	$843,757	$1,242,380	$2,250,427	$3,823,632
Scenario 6	$472,269	$680,548	$1,040,489	$2,056,849	$3,642,165

Figure 12 through Figure 14 show the percent rate increases (relative to 2005) for Missouri ratepayers for each of the three emission reduction cases and the six allocation scenarios within each case. For 2030, the rate increases range from about 8% to 35% in the Low Case, 32% to 80% in the Moderate Case, and 60% to 105% in the High Case. Missouri is slightly better off with emission based allocations than with load-based allocations.

FIGURE 12

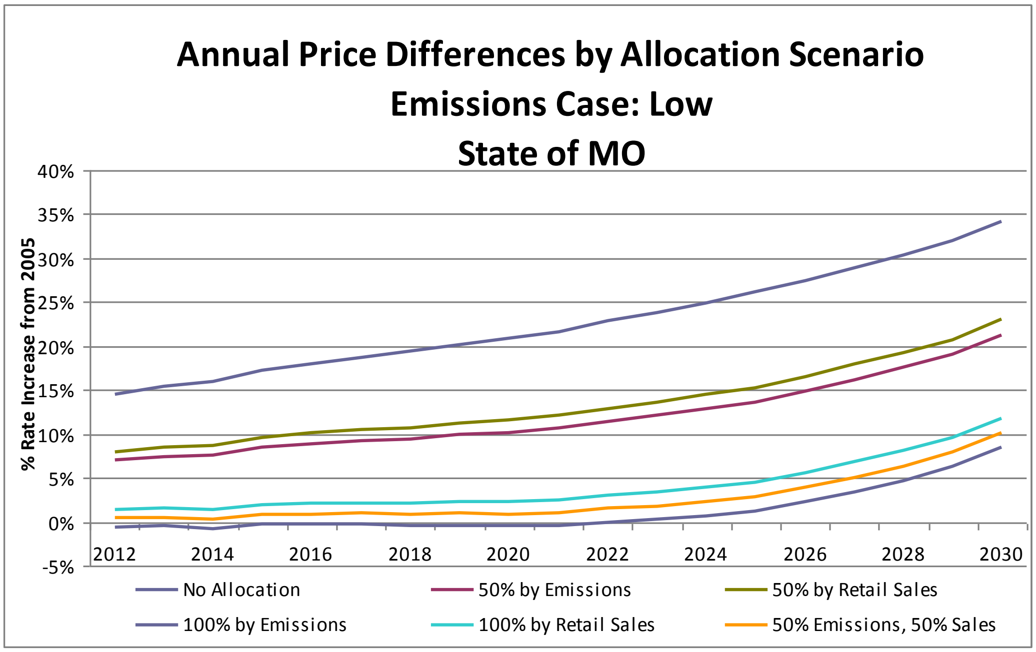


FIGURE 13

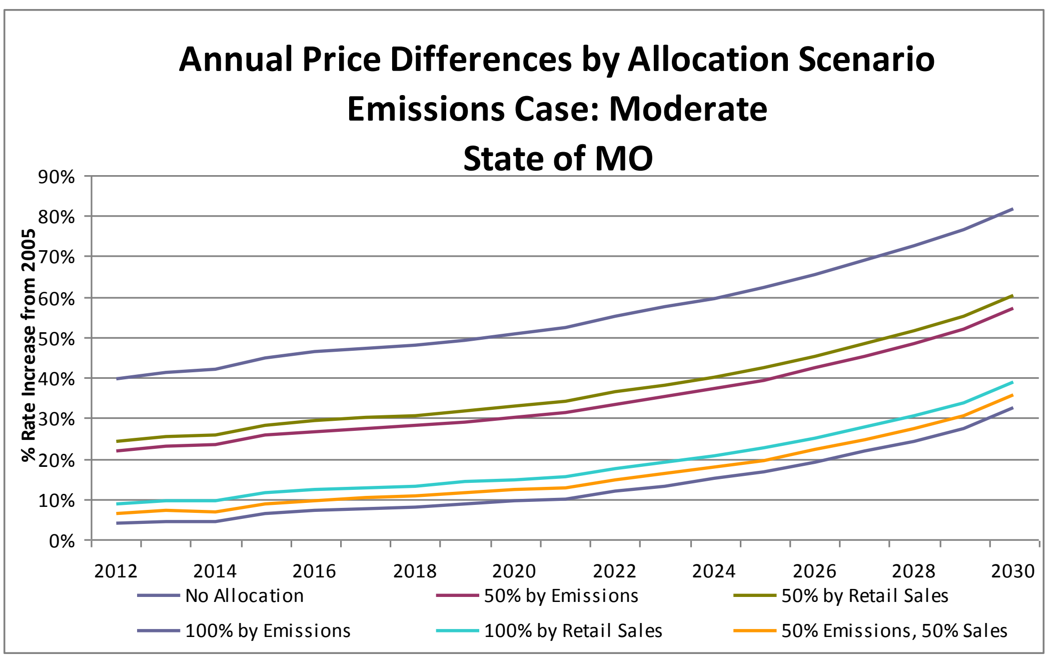
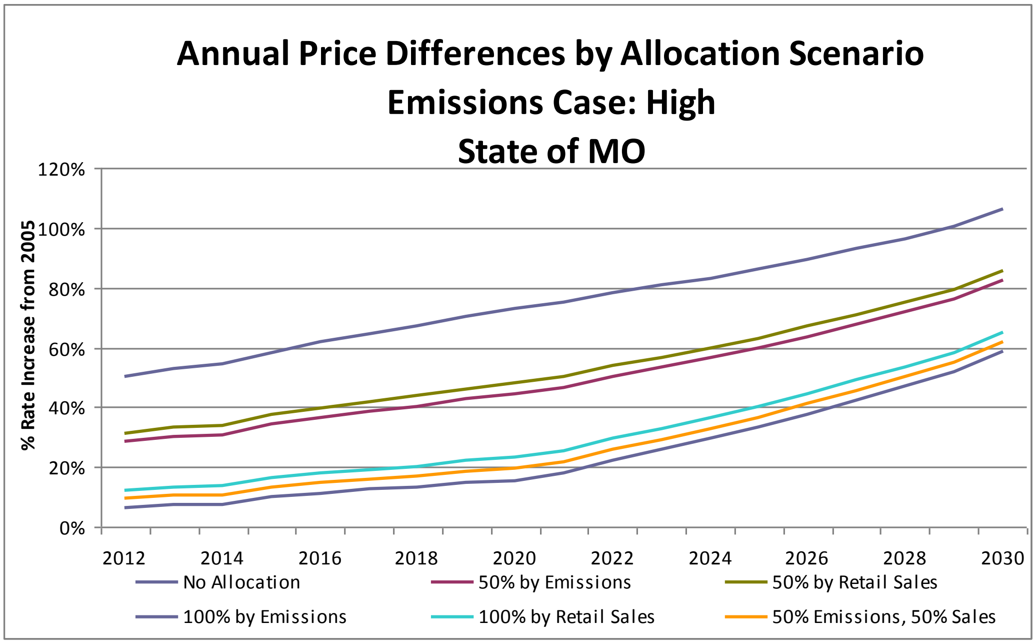


FIGURE 14



5.5. North Dakota

Table 6 shows the net cost impacts to North Dakota ratepayers under the three emissions reduction cases and six allocation scenarios. North Dakota sees relatively large differences between no-cost allocations and auctions, even in later years. This state also does considerably better with emissions-based no-cost allocations than load-based allocations.

TABLE 6
ANNUAL NET COST TO NORTH DAKOTA RATEPAYERS
(IN THOUSANDS OF 2005 DOLLARS)

	2012	*2015*	*2020*	*2025*	*2030*
Low					
Scenario 1	$123,704	$156,465	$217,768	$294,944	$393,731
Scenario 2	$59,428	$80,159	$120,705	$177,049	$266,162
Scenario 3	$79,319	$103,773	$150,743	$213,534	$305,641
Scenario 4	-$4,848	$3,853	$23,641	$59,155	$138,593
Scenario 5	$34,935	$51,081	$83,717	$132,124	$217,550
Scenario 6	$15,043	$27,467	$53,679	$95,639	$178,072
Moderate					
Scenario 1	$338,611	$409,095	$528,308	$703,210	$943,570
Scenario 2	$185,866	$240,956	$340,931	$487,835	$698,692
Scenario 3	$233,136	$292,990	$398,918	$554,486	$774,474
Scenario 4	$33,122	$72,818	$153,554	$272,459	$453,814
Scenario 5	$127,661	$176,885	$269,528	$405,763	$605,378
Scenario 6	$80,391	$124,851	$211,541	$339,111	$529,596
High					
Scenario 1	$432,466	$530,997	$759,904	$972,701	$1,222,149
Scenario 2	$243,668	$320,597	$499,636	$723,151	$988,212
Scenario 3	$302,095	$385,709	$580,180	$800,379	$1,060,608
Scenario 4	$54,869	$110,196	$239,368	$473,601	$754,274
Scenario 5	$171,723	$240,420	$400,457	$628,056	$899,066
Scenario 6	$113,296	$175,308	$319,913	$550,828	$826,670

Figure 15 through Figure 17 show the percent rate increases (relative to 2005) for North Dakota ratepayers for each of the three emission reduction cases and the six allocation scenarios within each case. For 2030, the rate increases range from about 18% to 50% in the Low Case, 60% to 120% in the Moderate Case, and 95% to 150% in the High Case. Because North Dakota uses a relatively large amount of coal, this state sees some of the greatest percentage rate impacts resulting from GHG emissions reduction programs.

FIGURE 15

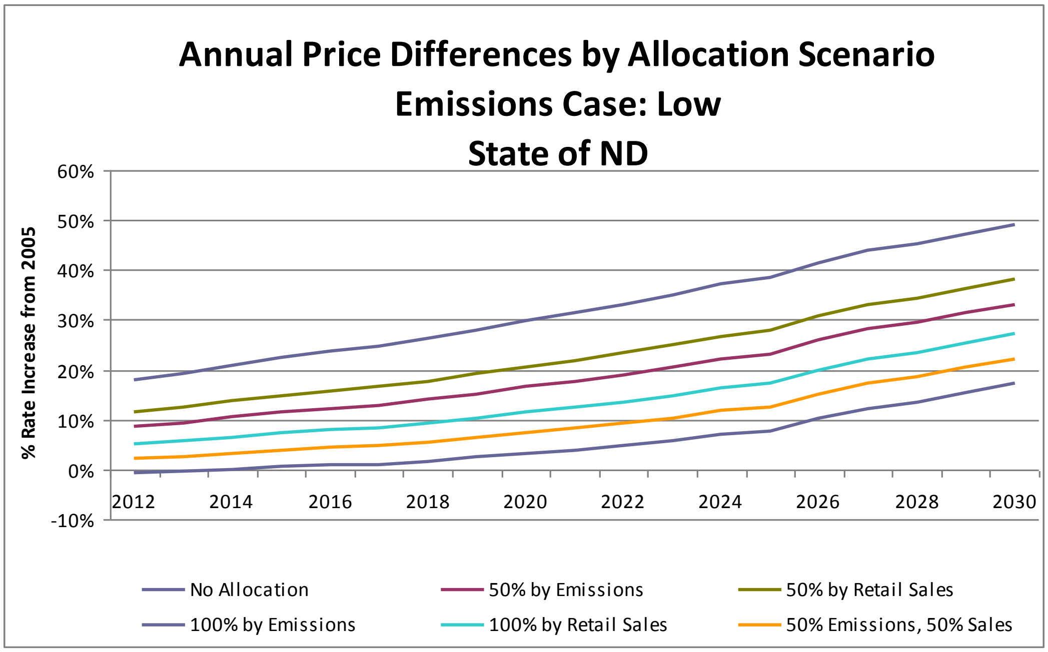


FIGURE 16

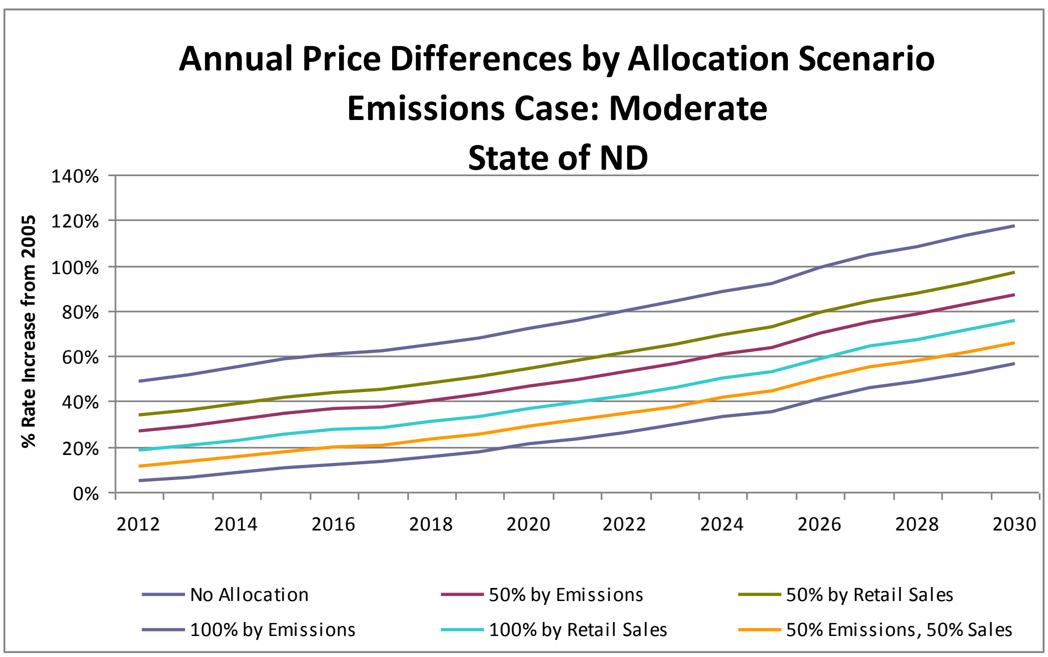
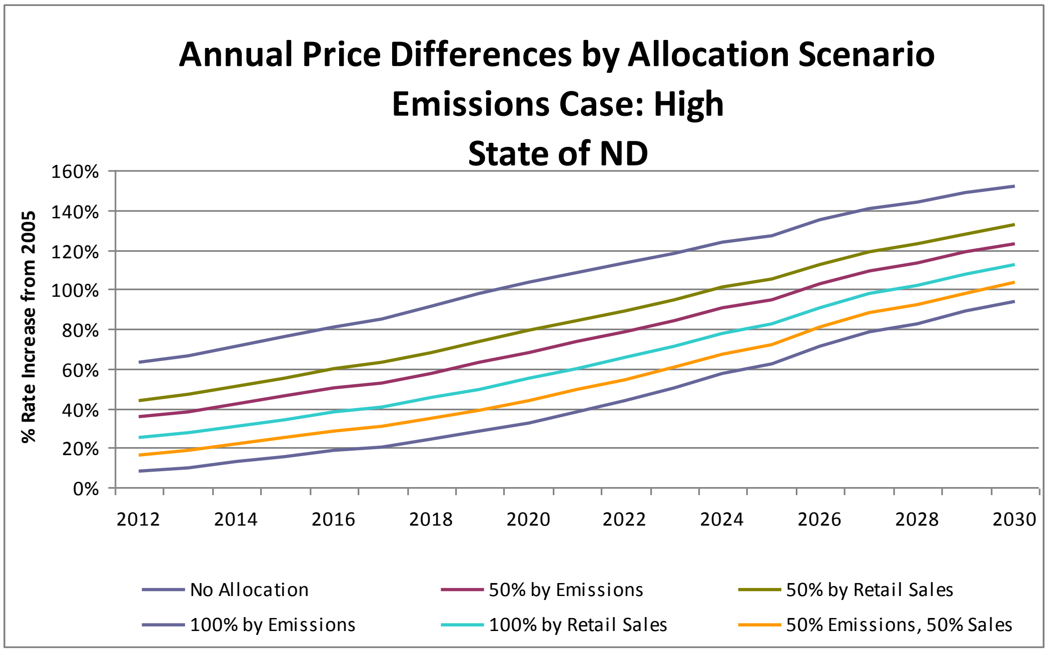


FIGURE 17



5.6. South Dakota

Table 7 shows the net cost impacts to South Dakota ratepayers under the three reduction cases and six allocation scenarios. South Dakota does best under the load-based no-cost allocations of Scenario 5. In fact, in the Low Case, South Dakota ratepayers see rate decreases through 2025 in Scenarios 5 and 6.

TABLE 7
ANNUAL NET COST TO SOUTH DAKOTA RATEPAYERS
(IN THOUSANDS OF 2005 DOLLARS)

	2012	*2015*	*2020*	*2025*	*2030*
Low					
Scenario 1	$57,860	$70,498	$91,857	$121,568	$166,313
Scenario 2	$28,301	$35,406	$47,219	$67,350	$107,646
Scenario 3	$17,689	$22,808	$31,194	$47,886	$86,585
Scenario 4	-$1,259	$314	$2,581	$13,133	$48,980
Scenario 5	-$22,483	-$24,882	-$29,470	-$25,796	$6,856
Scenario 6	-$11,871	-$12,284	-$13,444	-$6,332	$27,918
Moderate					
Scenario 1	$158,378	$184,325	$222,846	$289,845	$398,567
Scenario 2	$88,134	$107,000	$136,674	$190,798	$285,952
Scenario 3	$62,916	$79,241	$105,738	$155,239	$245,522
Scenario 4	$17,889	$29,676	$50,502	$91,750	$173,336
Scenario 5	-$32,547	-$25,843	-$11,370	$20,633	$92,477
Scenario 6	-$7,329	$1,917	$19,566	$56,191	$132,907
High					
Scenario 1	$202,278	$239,250	$320,535	$400,922	$516,240
Scenario 2	$115,452	$142,490	$200,842	$286,158	$408,656
Scenario 3	$84,281	$107,753	$157,872	$244,957	$370,033
Scenario 4	$28,627	$45,730	$81,149	$171,394	$301,072
Scenario 5	-$33,715	-$23,744	-$4,792	$88,993	$223,825
Scenario 6	-$2,544	$10,993	$38,179	$130,193	$262,448

Figure 18 through Figure 20 show the percent rate increases (relative to 2005) for South Dakota ratepayers for each of the three emission reduction cases and the six allocation scenarios within each case. For 2030, the rate increases range from about 2% to 20% in the Low Case, 10% to 50% in the Moderate Case, and 30% to 70% in the High Case. Overall, South Dakota sees less of an impact from GHG reduction requirements than many of the other states in the study. But South Dakota also shows fairly wide spreads between load-based and emissions-based auction recycling and no-cost allocations.

FIGURE 18

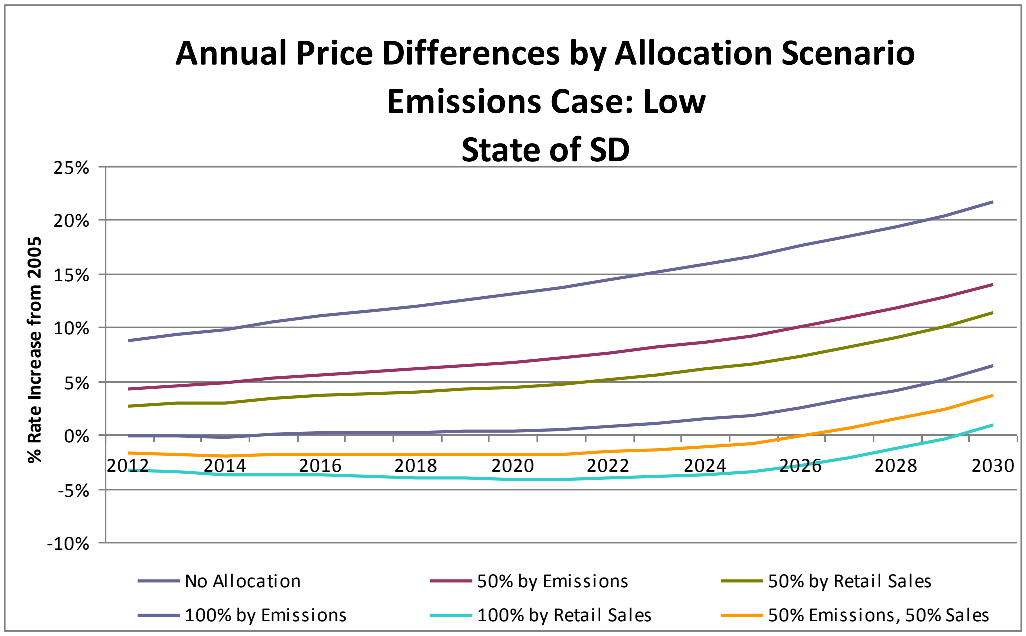


FIGURE 19

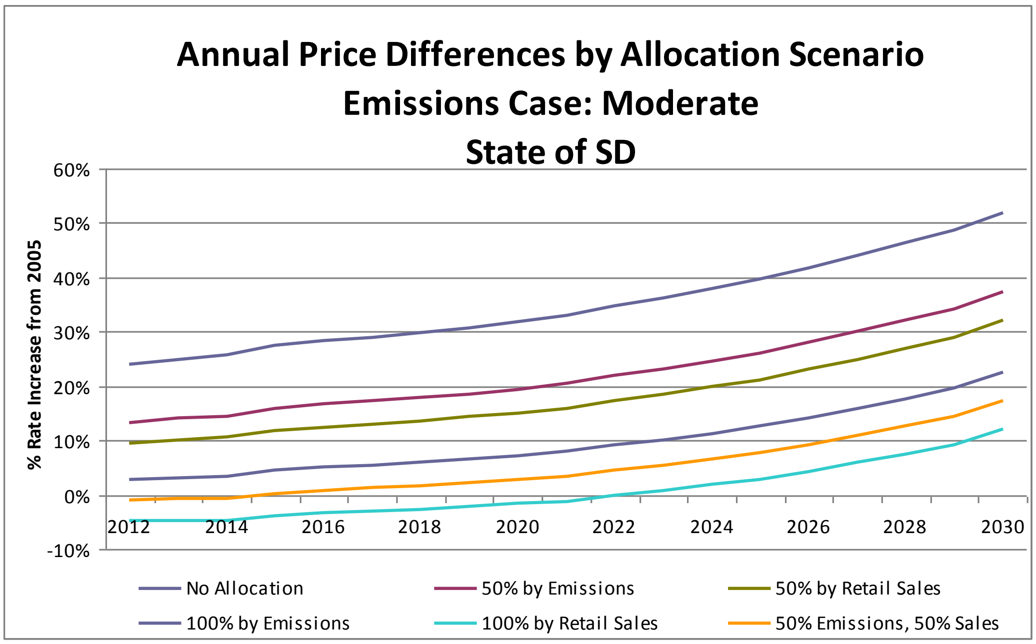
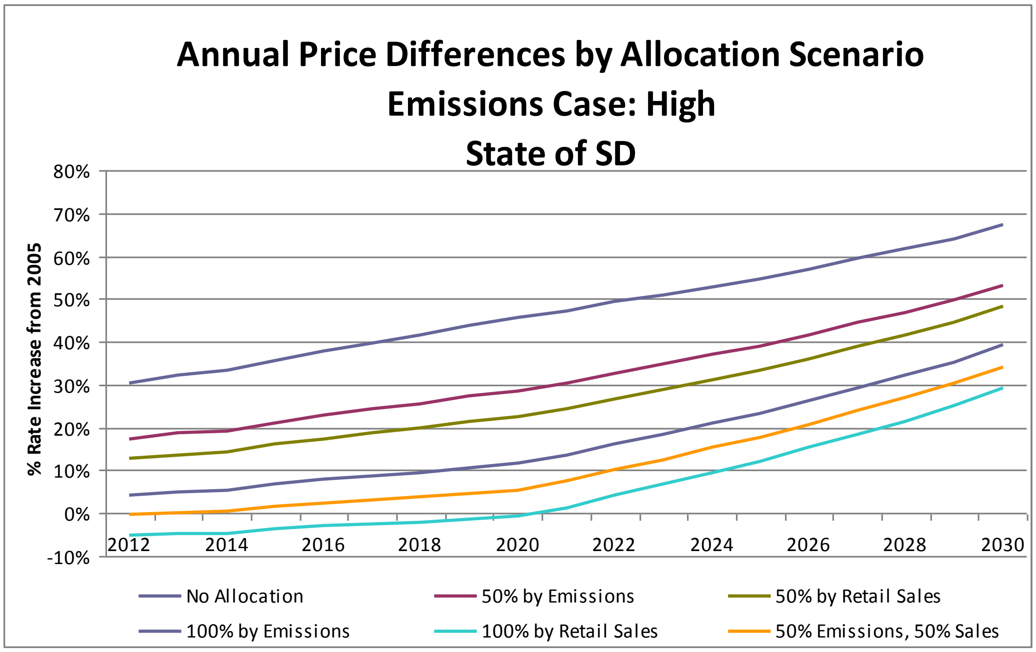


FIGURE 20



5.7. Wisconsin

Table 8 shows the net cost impacts to Wisconsin ratepayers under the three reduction cases and six allocation scenarios. Wisconsin ratepayers do better under emissions-based auction revenue recycling and no-cost allocations than under load-based auction revenue recycling and no-cost allocations, but the difference decreases as emissions reduction requirements become more severe. Additionally, Wisconsin is considerably better off with no-cost allocations even in the later years.

TABLE 8
ANNUAL NET COST TO WISCONSIN RATEPAYERS
(IN THOUSANDS OF 2005 DOLLARS)

	2012	*2015*	*2020*	*2025*	*2030*
Low					
Scenario 1	$609,057	$748,639	$1,003,303	$1,348,184	$1,847,888
Scenario 2	$302,458	$384,657	$540,306	$785,822	$1,239,379
Scenario 3	$321,066	$406,747	$568,405	$819,951	$1,276,310
Scenario 4	-$4,140	$20,676	$77,309	$223,459	$630,871
Scenario 5	$33,075	$64,856	$133,508	$291,719	$704,732
Scenario 6	$14,467	$42,766	$105,408	$257,589	$667,801
Moderate					
Scenario 1	$1,667,150	$1,957,402	$2,434,023	$3,214,361	$4,428,431
Scenario 2	$938,554	$1,155,376	$1,540,227	$2,187,012	$3,260,355
Scenario 3	$982,772	$1,204,051	$1,594,471	$2,249,362	$3,331,245
Scenario 4	$209,958	$353,349	$646,431	$1,159,664	$2,092,278
Scenario 5	$298,395	$450,699	$754,919	$1,284,363	$2,234,059
Scenario 6	$254,176	$402,024	$700,675	$1,222,013	$2,163,169
High					
Scenario 1	$2,129,250	$2,540,669	$3,501,030	$4,446,199	$5,735,881
Scenario 2	$1,228,673	$1,537,052	$2,259,543	$3,255,835	$4,619,991
Scenario 3	$1,283,329	$1,597,961	$2,334,889	$3,328,078	$4,687,714
Scenario 4	$328,096	$533,434	$1,018,056	$2,065,472	$3,504,100
Scenario 5	$437,408	$655,253	$1,168,748	$2,209,958	$3,639,546
Scenario 6	$382,752	$594,343	$1,093,402	$2,137,715	$3,571,823

Figure 21 through Figure 23 show the percent rate increases (relative to 2005) for Wisconsin ratepayers for each of the three emission reduction cases and six allocation scenarios. For 2030, the rate increases range from about 10% to 30% in the Low Case, 20% to 70% in the Moderate Case, and 55% to 90% in the High Case. Wisconsin has very similar impacts to Minnesota. It is also clear that emissions-based allocations are better than load-based allocations in terms of percent rate impacts for Wisconsin.

FIGURE 21

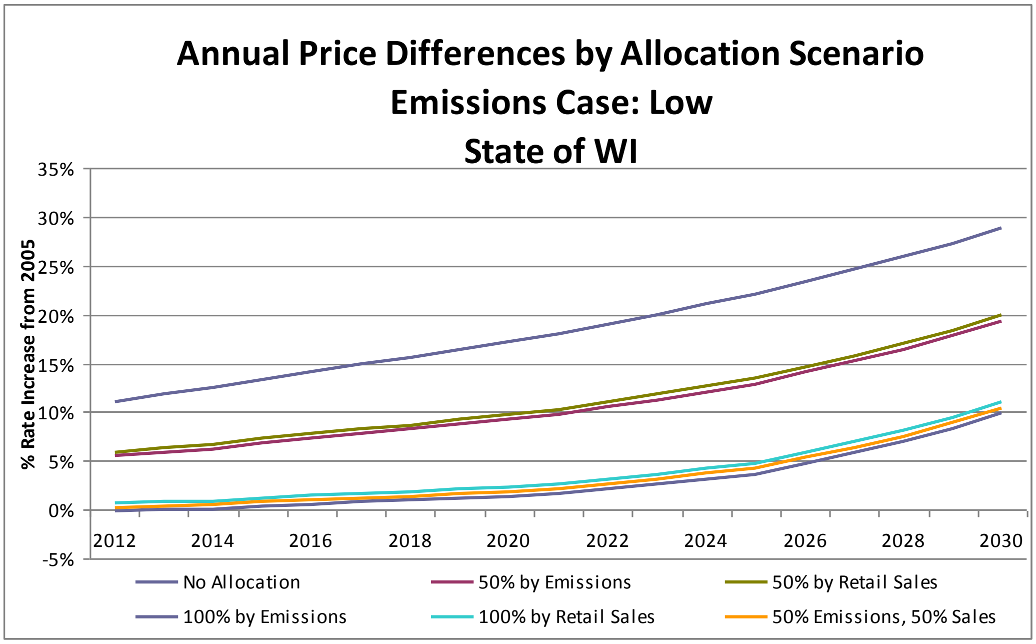


FIGURE 22

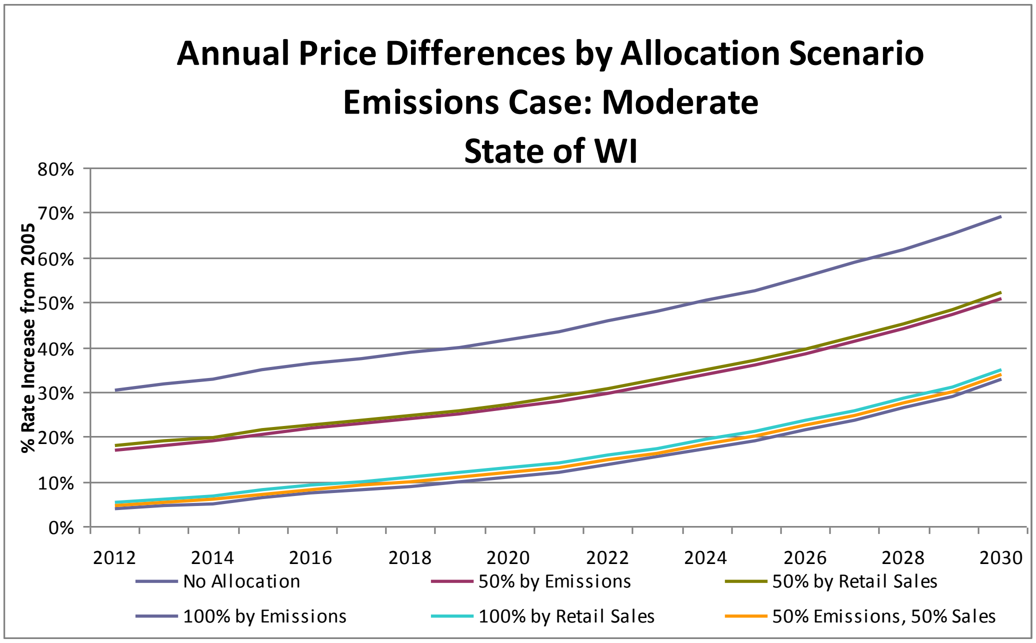
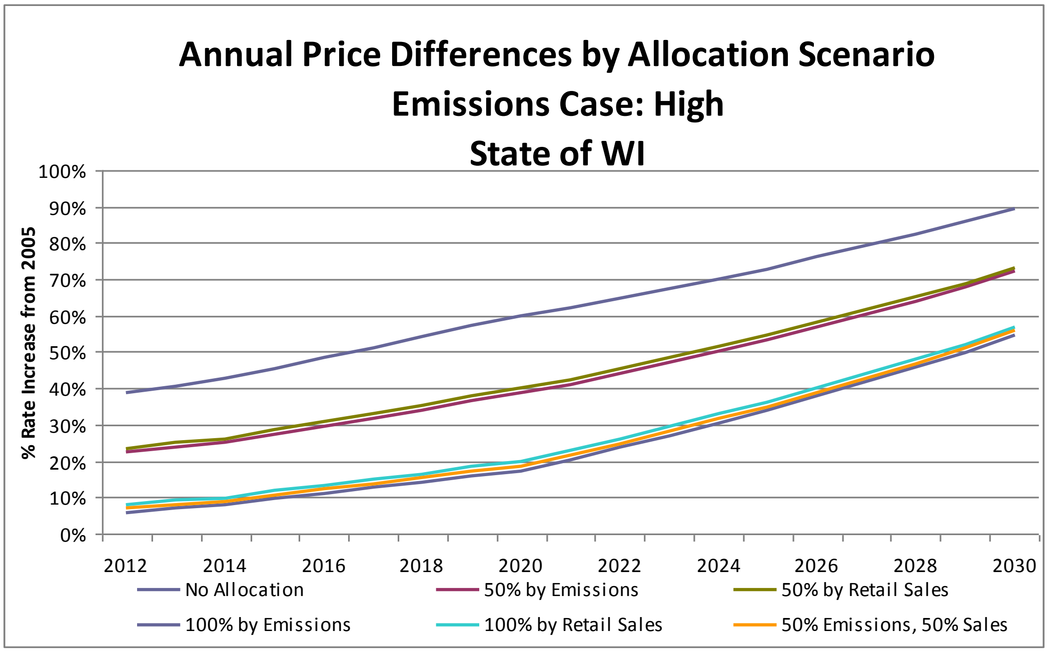


FIGURE 23



5.8. Comparisons Across States

Table 9 presents the average price increases relative to retail prices in 2005 over the 2012-2030 period for each of the allowance price cases (low, moderate or high), each of the scenarios, and each of the seven states included in this study. The rightmost "All" column presents a weighted average (based on 2005 loads) of the price increases for the seven states. The Table suggests that Indiana and North Dakota see the most significant rate impacts in the study area, while Minnesota, South Dakota, and Wisconsin see the lowest average rate impacts within the study area. Iowa and Missouri fall in the middle. For the seven states in aggregate, the average price increases from 2012 to 2030 range from a low of 3% to a high of 79% depending on the scenario.

TABLE 9
AVERAGE PRICE INCREASES 2012 – 2030
BY CASE, SCENARIO AND STATE

	IN	IA	MN	MO	ND	SD	WI	ALL
Low								
Scenario 1	30%	23%	20%	23%	32%	14%	19%	24%
Scenario 2	18%	13%	11%	12%	19%	8%	11%	14%
Scenario 3	21%	15%	11%	13%	23%	6%	11%	15%
Scenario 4	5%	3%	3%	1%	6%	1%	3%	3%
Scenario 5	11%	6%	3%	4%	14%	-3%	4%	6%
Scenario 6	8%	5%	3%	3%	10%	-1%	3%	5%
Moderate								
Scenario 1	74%	57%	48%	56%	79%	35%	46%	58%
Scenario 2	49%	37%	32%	35%	53%	22%	30%	38%
Scenario 3	55%	40%	31%	37%	61%	18%	31%	40%
Scenario 4	24%	17%	15%	13%	26%	10%	15%	17%
Scenario 5	36%	23%	14%	19%	43%	1%	16%	23%
Scenario 6	30%	20%	15%	16%	35%	5%	15%	20%
High								
Scenario 1	101%	77%	65%	76%	108%	48%	63%	79%
Scenario 2	71%	53%	45%	50%	76%	32%	44%	54%
Scenario 3	78%	57%	45%	54%	86%	27%	45%	58%
Scenario 4	41%	30%	26%	24%	44%	17%	25%	30%
Scenario 5	55%	37%	25%	31%	64%	6%	27%	37%
Scenario 6	48%	33%	25%	28%	54%	12%	26%	34%

6. CONCLUSIONS

The cost and rate impact estimates resulting from this study should be considered indicative of the potential magnitude of such impacts under alternative cap-and-trade regulatory regimes. But it is important to remember that there are considerable uncertainties inherent in these estimates. First and foremost, we do not know with any certainty the carbon emissions reductions that will be required by either regional programs in the Midwest or by federal legislation. It is often the case that early proposals for any new regulatory program are more aggressive than what the final program contains. In addition, we do not know what technology will be available, in what time frame, and at what cost. Significant advances in lower carbon emission generation technologies will ameliorate the potential impacts; but if such new technologies do not become available in a timely manner, the impacts could be even more severe than found by this study. And there are many moving parts besides technology. We assumed throughout this study that absent climate change legislation, the fuel mix of the studied areas remains the same as currently planned – but legislation in other areas – such as Renewable Portfolio Standards – could change the fuel mix and affect the results found in this study (either positively or negatively). The results are based on numerous other assumptions as discussed in this report, and an understanding of those assumptions is critical to interpreting and understanding the results.

One of the clear conclusions of the study is that the major determinants of rate impact on utility customers are first, the magnitude and timetable of reductions required, and second, whether allowances are auctioned or allocated at no-cost. The differences between emissions-based and load-based allocation policies for auction revenue recycling (or distribution of allowances at no cost) are less significant in comparison. This result held for all states and all study participants.

The study also concludes that if allowances are auctioned with no recycling of revenues back to the customers of LSEs, the potential rate impacts associated with GHG reduction programs can be huge, especially for LSEs that rely heavily on coal – but also for others as well. And while distributing allowances at no cost to LSEs helps the situation significantly, there are still substantial rate increases that are likely to occur, so allowance distribution at no cost to LSEs only helps mitigate rate impacts – not cure them.

APPENDIX A

MODEL RUNS FOR DETERMINING ALLOWANCE PRICES

The allowance prices of this study are based on the published model results that are listed below.

Low Case (Bingaman-Spector)

Energy Information Administration, Annual Energy Outlook, NEMS Model

S1766 Update, EIA AEO2008 NEMS run s1766_08.d031508a
S1766 Core, EIA AEO2007 NEMS run s1766_ d103007a
S1766 High Technology, EIA AEO2007 run s1766ht_d110807c
S1766, High Tech + CAFE + RPS, EIA AEO2007 run s1766polrp_d120507b

Environmental Protection Agency, ADAGE Model

S1766 ADAGE (EPA) Scenario 2 (Senate)
S1766 ADAGE (EPA) Scenario 3 No TAP
S1766 ADAGE (EPA) Scenario 10 No CCS Low Nuclear
S1766 ADAGE (EPA) Scenario 13 High Technology
S1766 ADAGE (EPA) Scenario 14, High Technology, No TAP
S1766 ADAGE (EPA) Scenario 20, High Technology, No CCS Subsidy, No TAP

Moderate Case (Lieberman-Warner)

Energy Information Administration, Annual Energy Outlook, NEMS Model

S2191 Core Case, EIA AEO2008 NEMS run s2191.d031708a.
S2191 Limited Alternatives Sources, EIA, AEO2008 NEMS run S2191biv.d031608a.
S2191 No International, EIA, AEO2008 NEMS run s2191noint.d032508a
S2191 High Cost, EIA AEO2008 NEMS run s2191hc.d031708a

Environmental Protection Agency, ADAGE Model

S2191 ADAGE (EPA) Scenario 2
S2191 ADAGE (EPA) Scenario 3 Limited International Action
S2191 ADAGE (EPA) Scenario 6 Constrained Nuclear and Biomass
S2191 ADAGE (EPA) Scenario 7 Constrained Nuclear, Biomass, CCS
S2191 ADAGE (EPA) Scenario 10 High Technology

MIT EPPM Model

MIT S2191, No Offsets, No CCS
MIT S2191, CCS Subsidy
MIT S2191, 15% Offsets
MIT S2191, 15% Offsets, CCS Subsidy

High Case (Sanders-Boxer)

MIT EPPM Model

MIT, 167 bmt (equivalent to Sanders/Boxer) - Core US & World Policy

MIT, 167 bmt (equivalent to Sanders Boxer) No Banking

MIT, 167 bmt (Equivalent to Sanders/Boxer) No Biofuels Trading

MIT, 167 bmt (Equivalent to Sanders/Boxer) Nuclear Expansion