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Electricity Restructuring, Environmental Policy, and Emissions

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Executive Summary

Since the late 1990s, several states have restructured their electric utilities to introduce retail competition for generation service. This includes almost all states in the Northeast from Virginia to Maine, plus California, Texas, Ohio, and Illinois.[1] Retail competition has been under review in other states, but not yet implemented or fully approved. In addition, wholesale electric markets are largely deregulated as a result of the transmission open-access and market-pricing authority orders from the Federal Energy Regulatory Commission (FERC).

The collapse of California's restructured electricity market has led many consumers, electricity producers, and policymakers to question the wisdom of bringing competition to retail electricity markets. Several states, including Oklahoma, New Mexico, and North Carolina, have put the brakes on earlier plans to implement or even consider adopting retail competition. The situation in California has also halted federal efforts to introduce nationwide electricity restructuring at the retail level.

Nevertheless, because cost-of-service regulation provides insufficient incentives to improve efficiency, competition in electricity generation remains an attractive alternative to regulation. Progress toward wide-scale adoption of electricity restructuring is, therefore, likely to resume. In the face of that eventuality, citizens, environmentalists, energy producers, and policymakers want to understand how greater competition in electricity markets is likely to affect emissions from the electricity sector and, ultimately, environmental quality.

Does open access to transmission increase use of older, higher-polluting coal-fired facilities in the Midwest and consequently increase emissions? Might the long-range transport of such emissions compromise the ability of eastern states to comply with the Clean Air Act's ozone standard? What would become of utility programs that promote demand-side management and the use of renewable energy sources? And if restructuring delivered the promised lower prices for electricity, would increased demand lead to higher emissions?

Restructuring could result in substantial changes in the mix of generation technologies employed to produce electricity, the efficiency of power plant operations, and the price and quantity of electricity traded in the marketplace—each of which can affect emissions.

This study looks at the effects of restructuring on air emissions of nitrogen oxides (NO_x) and carbon dioxide (CO_2).[2] It addresses the expected impacts of restructuring under alternative air emissions regulations. It does not attempt to measure the impacts of the industry restructuring that have occurred to date. As of early 2001, about one-third of the United States had introduced retail access, and this partial restructuring forms the baseline for our study. We seek to estimate impacts on air emissions of moving to full retail access—nationwide restructuring.

For NO_x emissions, the baseline for this study is the summer season, cap-and-trade program for the Northeast ozone transport region (OTR). The study compares this baseline with two alternative and more extensive NO_x regulatory regimes. The first alternative expands the Northeast OTR program to a much wider geographic area—the eastern half of the United States. The second alternative extends the cap-and-trade program for the eastern United States from summer only to year-round. For CO_2 emissions, the study baseline is today's current policy of no regulation, and the two alternative policies are a $25-per-metric-ton and a $75-per-metric-ton carbon tax. We conducted a series of large-scale simulation analyses incorporating the three NO_x regulatory scenarios, plus one NO_x scenario with and without the two levels of carbon taxes.

The study simulates the operation of the electric power industry for the year 2008. The modeling provides geographic detail at the level of 13 subregions (see note to Figure A) of the North American Electric Reliability Council (NERC) and estimates generation output (by fuel type), capacity mix, electricity prices, and air emissions. In addition, the modeling estimates the costs of complying with air emissions control regulations.

Questions Addressed

The study attempts to estimate and evaluate the effects of both industry restructuring and different methods of regulating NO_x and CO_2 emissions. In doing so, it addresses two sets of questions concerning potential impacts of both areas of regulatory reform.

The first set concerns the expected impacts of moving to nationwide restructuring over the next decade for a given NO_x regulatory policy regime (and no regulation of CO_2). The study seeks to estimate how moving to a fully restructured industry will affect the mix of both generation (i.e., coal versus natural gas) and installed capacity, the total amount of installed capacity, the price of electricity for consumers, and the level of air emissions. An additional question is how a renewables portfolio standard will affect fuel mix, emissions, and customers' electricity prices.

The next set of questions concerns the impacts on the electricity industry and electricity customers of alternative ways of regulating NO_x and CO_2 emissions. In particular, what are the impacts of the alternatives on the levels of these emissions, cost of compliance, end-use electricity prices, and generation mix?

Methodology

The analytical tool for this study is an industry-wide simulation model, called Haiku, developed by Resources for the Future (RFF). Haiku is an optimization model that simulates the dispatch of generating units within each of 13 NERC subregions, based on economic (i.e., cost) and engineering inputs and demand response to change in price. The model contains an interregional, power-trading component that solves for transfers of power across subregions. Haiku's investment component adds new generating capacity based on reliability and economic least-cost criteria. The model can retire generating capacity that it finds no longer economical to operate. Additionally, the model can solve for the least-cost mix of NO_x emissions-control technologies.

Haiku simulates both electricity supply and demand, calculating generation costs and solving for market-clearing prices. Electricity demand in the model adjusts in response to changes in end-use electricity prices. The model is capable of determining end-use prices by using the traditional regulated utility method (average embedded cost), or by assuming a deregulated market (marginal cost for the generation component and average embedded costs for other components of electricity service). Detailed information about Haiku appears in the Appendix.

The study is conducted by first running Haiku using a baseline that reflects current conditions: a partially restructured industry, NO_x OTR cap-and-trade only for the Northeast (OTR seasonal), and no CO_2 regulation. The next step is to assume a change from partial to full, nationwide restructuring and modify certain Haiku baseline input assumptions accordingly. Restructuring leads to the following changes in assumptions:

- In regions adopting restructuring, prices for electricity generation reflect marginal cost; elsewhere, end-use prices are based on average embedded, or “accounting,” costs. In addition, industrial customers in the retail access regions face time-of-day pricing (based on marginal cost).
- Restructuring produces certain production efficiencies: improved plant availability, lower heat rates, and lower power-plant, nonfuel operation and maintenance costs.
- Nationwide restructuring motivates an expansion in interregional transmission capability that makes possible increased power transfers.
- Nationwide restructuring is accompanied by the introduction of a renewables portfolio standard.

Next, the study explores the interaction of nationwide restructuring and the alternative NO_x regulatory policy scenarios. Haiku is run with partial versus nationwide restructuring for

- OTR seasonal cap-and-trade for the Northeast;
- SIP seasonal cap-and-trade for the eastern half of the United States (the 19 states in the U.S. Environmental Protection Agency’s (EPA) NO_x state implementation plan, known as the SIP Call region); and
- SIP annual cap-and-trade.

Table A summarizes these three scenarios.

TABLE A. HAIKU MODEL RUN — NO_x EMISSIONS SCENARIOS, 2008

	OTR seasonal	*SIP seasonal*	*SIP annual*
Geographic scope (NERC subregions)	MAAC, NE, NY	OTR seasonal plus MAIN, ECAR, STV	Same as SIP seasonal
Temporal scope	May–September	May–September	Year-round
Average emissions rate	0.15 lbs./MMBtu	0.15 lbs./MMBtu	0.15 lbs./MMBtu
Trading allowed?	Yes	Yes	Yes

Note: MMBtu is million British thermal units. For explanation of NERC subregions, see Figure A.

A separate set of Haiku runs analyzes the effects of carbon taxes set at $25 per ton and $75 per ton. Here the baseline is nationwide restructuring with the SIP seasonal NO_x policy. We also assume that the market response to the carbon tax is limited to fuel-switching and price-elasticity effects (reduction in demand as the price increases); technologies to reduce carbon emissions after combustion are excluded because such innovations are not practical for the foreseeable future.

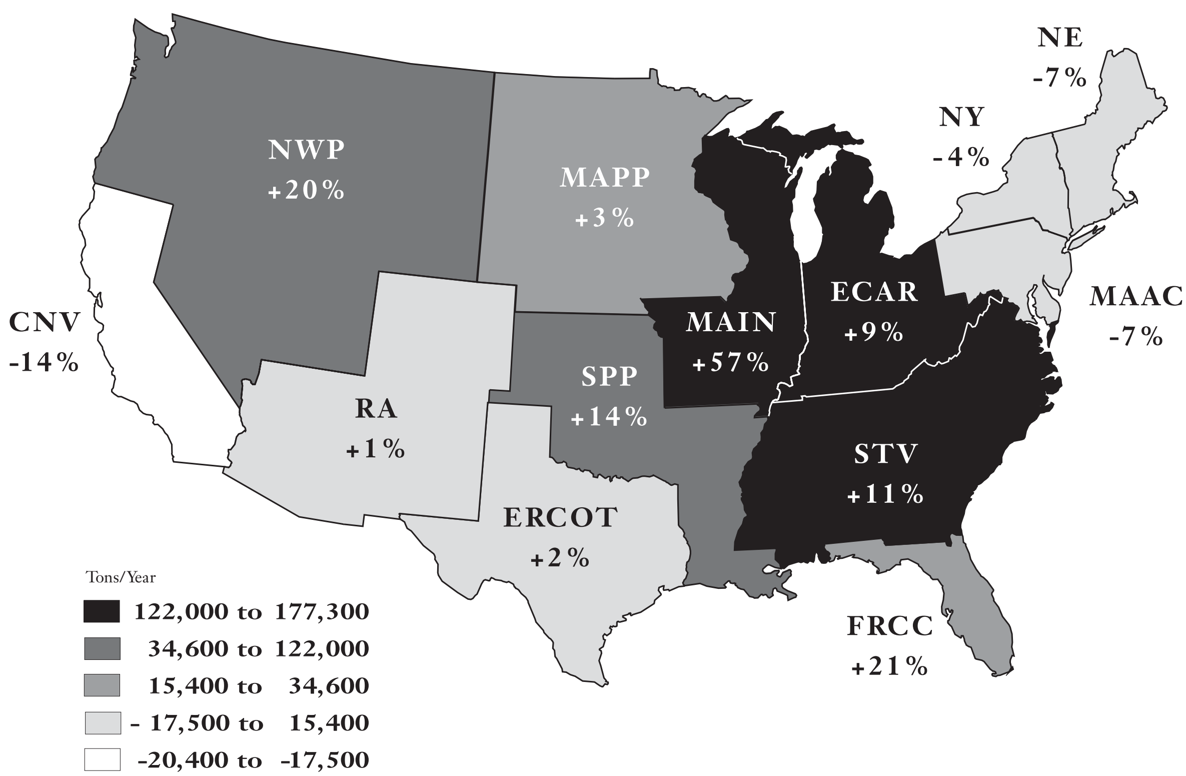
A final component of the study is a sensitivity analysis. Because the nationwide restructuring scenario involves changes to several inputs (e.g., pricing method, transmission-transfer capacity, unit heat rates) based on assumptions that are inherently uncertain, a set of Haiku runs was performed changing one assumption at a time. This allows us to evaluate which of the restructuring assumptions were most important.

TABLE B. ANNUAL NO_x EMISSIONS IN THE SIP CALL REGION, 2008 (THOUSAND TONS)

Policy regime	*Partial restructuring (baseline)*	*Nationwide restructuring*
OTR seasonal	3,449	3,866
SIP Call seasonal	2,418	2,672
SIP Call annual	1,041	1,048

FIGURE A.

CHANGE IN ANNUAL NO_x EMISSIONS DUE TO NATIONWIDE RESTRUCTURING UNDER THE NO_x BASELINE, BY NERC SUBREGION



North American Reliability Council (NERC) subregions

ECAR	MI, IN, OH, WV; part of KY, VA, PA
ERCOT	Most of TX
MAAC	MD, DC, DE, NJ; most of PA
MAIN	Most of IL, WI; part of MO
MAPP	MN, IA, NE, SD, ND; part of WI, IL
NE	VT, NH, ME, MA, CT, RI
NY	NY
FRCC	Most of FL
STV	TN, AL, GA, SC, NC; part of VA, MS, KY, FL
SPP	KS, MO, OK, AR, LA; part of MS, TX
NWP	WA, OR, ID, UT, MT; part of WY, NV
RA	AZ, NM, CO; part of WY
CNV	CA; part of NV

Results

The results of this study are complex because it involves numerous outputs (by geographic region) and emissions-control scenarios that interact.

We find that restructuring leads to substantially higher use of existing coal-fired facilities and reduced use of natural gas. Under the assumptions in this study, including time-of-day pricing of electricity for industrial customers in restructured regions, we find that restructuring leads to lower electricity prices and higher levels of total generation.

Without new caps on NO_x emissions in the SIP Call region, nationwide restructuring yields higher NO_x emissions (Table B, Figure A). However, SIP policies to cap emissions of NO_x would mitigate most or all of these increases in the SIP Call region. Consistent with the increase in coal generation, nationwide restructuring also yields higher carbon emissions.

When we analyze the effects of different assumptions, we find that the way prices are set—through competitive markets with time-of-day prices for industrial customers or through cost-of-service regulation—most affects the mix of fuels used to generate electricity and the level of NO_x and carbon emissions. Eliminating time-of-day pricing from the nationwide restructuring scenario causes electricity prices to rise and generation to fall, compared with the levels in the baseline. Without time-of-day prices, emissions of NO_x and carbon also fall, but this reduction would offset only a portion of the increases resulting from the shift to nationwide restructuring.

Our results are consistent with earlier research suggesting that restructuring could have adverse environmental effects. However, the consequences are not inevitable. Any increased NO_x emissions in the eastern United States could be fully mitigated by extending the seasonal NO_x cap-and-trade program in the SIP Call region from summer to year-round. This mitigation can be achieved at an electricity price below that in the baseline. Implementing nationwide restructuring plus an annual cap-and-trade program for NO_x will lead to a lower electricity price. Though hardly a complete measure of the benefits of restructuring or the costs of environmental policy, this price result does suggest that restructuring could increase our capacity to afford such environmental improvements as reducing emissions of greenhouse gases.

TABLE C. IMPACTS OF CARBON TAXES, 2008*

	$25/ton tax	*$75/ton tax*
Carbon reductions	–3.8%	–15.7%
NOx reductions	–3.9	–19.1
End-use electricity rates	+4.9	+19.1
Coal-fired generation	–5.1	–21.1

*All figures are nationwide except for NO_x reduction, which is for the SIP Call region. The baseline is SIP seasonal for NO_x and nationwide restructuring.

We also looked at how carbon policies might affect the electricity sector's NO_x emissions and found important ancillary reductions. Moreover, in the scenarios we analyze, NO_x emissions generally are more responsive to carbon taxes, as measured by percentage reduction from baseline, than are carbon emissions (Table C). The ancillary emissions-reduction benefits depend on the assumptions about NO_x policy in the baseline but could enhance the overall cost-effectiveness of both NO_x and carbon policies.

CHAPTER ONE

Introduction

The American electric power industry is undergoing dramatic changes in the way it is structured and regulated. Electricity restructuring was set into motion with the passage of the Energy Policy Act of 1992. The act called on the Federal Energy Regulatory Commission (FERC) to order all jurisdictional, transmission-owning utilities to allow access to their transmission systems at nondiscriminatory, cost-based transmission rates to facilitate competitive wholesale power transactions.[3] Most of the deregulatory activity directed at retail markets has been at the state level. As of July 2001, retail electricity markets in several states, including Pennsylvania, Texas, and most of the northeastern states from Maryland to Maine, had been opened to competitive energy suppliers, and electricity consumers in those areas were allowed to pick their retail electricity provider.[4] Virginia is in the process of opening its markets to competition. Oregon has completed implementation of its plan, which allows open choice of retail providers for commercial and industrial customers but only a limited set of service options for residential customers, all of which are supplied at regulated rates. The collapse of the California electricity market and subsequent decisions by several states, including Oklahoma and New Mexico, to delay implementation of competition have led some industry observers to conclude that the spread of competition to other states will likely cease. Others believe that in the long run, the fundamental features of electricity supply that are driving regulators to allow competition are not going away and competition will continue to spread.

One important unanswered question throughout the debate about electricity restructuring, at both the wholesale and the retail market levels, is how the move from regulation to competition will affect the environment.

One important, unanswered question throughout the debate about electricity restructuring, at both the wholesale and the retail market levels, is how the move from regulation to competition will affect the environment.[5] During the debate over FERC orders to open access to transmission systems, environmentalists and others raised concerns that allowing more open access to transmission would increase use of older, higher-polluting, coal-fired facilities in the Midwest and consequently increase emissions. Of particular concern to the eastern states was the possibility that the long-range transport of such emissions would adversely affect their ability to comply with the ozone standard. As states debated whether to allow retail competition, environmentalists also became concerned about the potential demise of utility programs that promoted demand-side management and the use of renewable energy sources. In addition, if restructuring delivered the promised lower prices for electricity, then increased levels of electricity demand induced by the lower prices could also yield higher emissions.

Competition in electricity markets and associated new opportunities for expanded interregional electricity trading could result in substantial changes in the mix of generation technologies employed to produce electricity, the efficiency of power plant operations, and the price and quantity of electricity traded in the marketplace. At the same time, electricity generators in the eastern United States are expecting new restrictions on emissions of NO_x. All of these changes will have implications for NO_x emissions, with associated potential impacts on air quality.

How competition affects NO_x emissions from the electricity sector depends on how competition affects the performance of the generation sector, the turnover of the existing capital stock, the amount of interregional electricity trade, the price of electricity, and total electricity demand, among other things. In an earlier study (Burtraw et al. 2000), we used RFF's regional electricity market and interregional trading model (called Haiku), to analyze how restructuring and expected NO_x policies could affect emissions of NO_x from electricity generators in the near term. That study looked at two alternative restructuring scenarios combined with several NO_x policy regimes. It characterized changes in electricity prices, electricity generation, interregional electricity trade, NO_x emissions, and the costs of pollution control that would likely take place in the near term under alternative scenarios for regulatory and environmental policy.

As states debated whether to allow retail competition, environmentalists also became concerned about the potential demise of utility programs that promoted demand-side management and the use of renewable energy sources.

The 2000 study found that restructuring was likely to have a modest impact on NO_x emissions from electricity generators. Absent new NO_x regulation, electricity restructuring was likely to cause up to a 4% increase in annual NO_x emissions nationally from the electricity sector by the year 2003, the time frame considered. The bulk of this increase would occur in the seven eastern NERC subregions (NE, NY, MAAC, STV, FPCC, ECAR, and MAIN). The impact on NO_x emissions in MAAC would be smaller than in the eastern region as a whole, with only a 2.5% increase under the aggressive restructuring scenario.

In this study, special attention is given to the MAAC region because it is bordered by states that have yet to undergo electricity restructuring.

The present study uses a revised version of the Haiku model to analyze how expansion of electricity restructuring (beyond those states that have already implemented retail competition) is likely to affect emissions of NO_x and carbon from electricity generators. The results are likely to differ from the earlier study for several reasons. First, the revised Haiku model has endogenous power plant investment and retirement decisions. Second, the new model has updated assumptions about the costs and performance of NO_x control options. Third, this study looks at a longer time frame and makes different assumptions about how restructuring is likely to affect the amount of transmission capacity and the performance of generators. It compares a baseline—a partial restructuring scenario—with nationwide restructuring under three NO_x regulatory policies. The nationwide restructuring scenario is based on a number of assumptions about how expanded restructuring is likely to affect industry productivity, interregional transmission capability, and use of renewables. To determine which assumptions are the important drivers of our results, we perform several sensitivity analyses to reveal how specific parameter assumptions or groups of assumptions affect the results.

In addition to looking at the effects of more widespread restructuring on electricity-sector NO_x emissions, we also analyze the effects of policies designed to limit emissions of greenhouse gases on NO_x emissions from electricity generators. We analyze two carbon taxes imposed on electricity generators: $25 per metric ton and $75 per metric ton of carbon.

We find that restructuring leads to substantially higher use of existing coal-fired facilities and reduced use of natural gas. Under the standard assumptions in this study, including time-of-day pricing of electricity for industrial customers in restructured regions, we find that restructuring leads to lower electricity prices and higher levels of total generation in both the eastern United States and nationwide. In the absence of new caps on NO_x emissions in the eastern states, nationwide restructuring yields higher NO_x emissions. However, policies to cap emissions of NO_x in the eastern states mitigate most or all of these increases in that region. Consistent with the increase in coal generation, nationwide restructuring also yields higher carbon emissions.

Restructuring leads to substantially higher use of existing coal-fired facilities and reduced use of natural gas.

In our sensitivity analyses, we find that with more widespread restructuring, the change from regulated to market-based pricing is a more important determinant of changes in the mix of fuels used to generate electricity and the level of NO_x emissions than any of the specific parameter assumptions. Eliminating time-of-day pricing from the nationwide restructuring scenario results in an increase in electricity prices above the level in the partial restructuring baseline, as well as a reduction in generation below the baseline level. In a scenario without time-of-day prices, emissions of NO_x and carbon are also lower, but not as low as under the partial restructuring baseline.

Our analysis of the ancillary benefits of carbon policies indicates that carbon policies directed at the electricity sector can yield important ancillary reductions in emissions of NO_x. In the scenarios that we analyze, NO_x emissions generally are more responsive (in percentage terms) to the imposition of carbon taxes than are carbon emissions.

The rest of this report is organized as follows. Chapter Two discusses previous research and the regulatory context. Chapter Three describes the baseline and alternative policy scenarios used in the modeling. Chapter Four presents results. Chapter Five explains the process and results of the sensitivity analysis we conducted to determine which factors had the most impact on the model results. Chapter Six looks at the ancillary benefits of an electricity-sector carbon policy. Chapter Seven concludes, and an Appendix describes the Haiku model in detail.

■ ■ ■

CHAPTER TWO

Building on Prior Research

A limited body of earlier research offers a range of perspectives on how restructuring is likely to affect emissions of NO_x and other pollutants, but the compendium of evidence is far from conclusive, partly because many assumptions underlie the various scenarios. Several of these studies, including those by Lee and Darani (1996), the Center for Clean Air Policy (1996a, 1996b, 1996c), Exeter Associates and Environmental Resource Management (1997), and Rosen et al. (1995), find potentially large effects from increased interregional power trading on coal plant utilization and emissions of NO_x and CO_2. In two analyses of the proposed environmental impacts of its two transmission orders, FERC (U.S. FERC 1996b, 1999) finds a much more limited effect of increased power trading on air emissions. The Energy Information Administration (U.S. EIA 1996) also finds that open transmission access increases NO_x emissions minimally, by 1% to 3% above the baseline scenario, with the largest effects in the early years.

In an earlier study, Palmer and Burtraw (1997) look at the potential impacts of electricity restructuring on emissions of NO_x and CO_2 and on subsequent changes in atmospheric concentrations of NO_x and nitrates at the regional level, plus the ultimate effect on human health. Their results concerning emissions effects fall roughly in the middle of the estimates from the prior literature. Burtraw et al. (2000) finds substantially smaller impacts of electricity restructuring on emissions of NO_x and CO_2 in the near term than have most previous studies, with NO_x emissions increases of 4% or less relative to the baseline and annual carbon emissions increases of just under 2% in the absence of policies to promote renewables. The Department of Energy (U.S. DOE 1999) looks at the emissions effects of the Clinton administration's Comprehensive Electricity Competition Act of 1999 and demonstrates that the provisions to promote greater use of renewables and distributed generation will lead to a reduction in both NO_x and carbon emissions, compared with a regulated baseline.

Most of the prior analyses of the effect of restructuring on emissions ignored the effect of a 1998 EPA ruling calling on many eastern states to reduce summer NO_x emissions from electricity generators.[6] This state implementation plan (SIP) ruling, known as the NO_x SIP Call, is designed to address problems of long-range transport of ozone in the eastern United States by requiring the states to mandate reductions in summertime NO_x emissions. For emissions from stationary sources, including electricity-generation facilities, the requirement for reductions in NO_x emissions is coupled with a regional cap-and-trade program for NO_x emissions. As recently reconstituted by the courts, the SIP Call region includes 19 states and the District of Columbia.[7] The five-month summer emissions cap under this program is based on an average emissions rate for NO_x of about 0.15 pounds per MMBtu of heat input at fossil fuel-fired boilers. Nationwide, the program would lead to annual reductions in NO_x emissions of 22% by 2007 and summertime reductions of 40% in the same year.[8] In the SIP Call region, the program would reduce NO_x emissions by 40% annually in 2007 and by 62% in the summer season.[9] By imposing summertime caps on NO_x emissions that apply to both new and existing generating facilities, this program eliminates the possibility for aggregate summertime NO_x emissions in the SIP Call region to increase as a result of restructuring.

Nonetheless, emissions of NO_x during other seasons, and in other regions, could rise as a result of increased power trading or increased generation to meet higher levels of demand brought about by anticipated lower prices under competition. These additional NO_x emissions could contribute to higher concentrations of ground-level ozone. Moreover, additional NO_x emissions could contribute to higher concentrations of particulate matter, which have been firmly associated with both human morbidity and mortality effects and are considered by many health scientists to pose a more serious threat to human health than ozone concentrations. In addition, NO_x emissions are deposited as nitrates, contributing to such environmental problems as acidification of some ecosystems and nutrification of water bodies.

Environmentalists have proposed expanding the NOx SIP Call to be an annual program.

If there were an annual cap on emissions of NO_x from electricity generators in the East, then restructuring would have no effect in the capped region on aggregate NO_x emissions.[10] Environmentalists have proposed expanding the NO_x SIP Call to an annual program.[11] Burtraw et al. (2000) analyze the cost-effectiveness of different NO_x policies, including both a SIP seasonal and a SIP annual policy. They find that an annual NO_x emissions cap in the SIP Call region yields nearly $400 million in annual net benefits (benefits less costs) in 2008 not realized with a seasonal policy. In their analysis, they assume that no additional states move to implement electricity restructuring beyond those states that had made a decision as of 2000. Thus, they do not consider how further changes in economic regulation facing the industry might affect the cost-effectiveness of different NO_x regulatory policies.

In this context, the present study analyzes how expansion of electricity restructuring, beyond those states that have already implemented retail competition, is likely to affect emissions of NO_x and carbon from electricity generators. We also analyze the ancillary effects of carbon reduction policies in the electricity sector on NO_x emissions.

■ ■ ■

CHAPTER THREE

Scenarios

This analysis measures the effects of more extensive restructuring by comparing the results of two scenarios. One is a baseline scenario that represents the electricity sector assuming no further restructuring beyond what states had committed to as of 2000. The second is a nationwide restructuring scenario in which all regions of the country are assumed to have market-based pricing of electricity by 2008.

Each scenario, described in more detail below, is analyzed under three sets of assumptions regarding the environmental regulatory regime governing emissions of NO_x from the electricity sector. The NO_x policy baselines, which also are described below, are (1) the status quo, which we call ozone transport region (OTR) seasonal; (2) a policy labeled SIP seasonal that reflects the level of controls called for in EPA's NO_x SIP Call; and (3) an annual version of the SIP Call. Table 1 shows the combinations of NO_x policy baselines and restructuring policy scenarios that are included in the analysis. The table also indicates that the nationwide restructuring scenario served as the benchmark scenario for both the decomposition analysis and the analysis of the ancillary NO_x emissions reduction benefits of carbon taxes in the electricity sector.

The analysis takes a medium-term view of the effects of restructuring and focuses on the year 2008. We chose 2008 because we believe it would take several years for the currently regulated states to make a transition to competitive markets if they attempt to do so. The 2008 date also allows time for electricity generators to adjust to the different incremental NO_x policies that we analyze, all of which are scheduled to take effect in 2004.[12] To represent our assumptions about the timing of electricity restructuring in the different scenarios and to eliminate any potential terminal-year problems associated with concluding the model runs in 2008, we ran the model for the years 2004, 2008, and 2012 but report results for 2008 only.

TABLE 1. BASELINES AND POLICY SCENARIOS

	Restructuring policy scenarios	
Alternative NO_x policy baselines	**Partial restructuring (baseline)**	**Nationwide restructuring**
OTR seasonal NO_x	yes	yes
SIP seasonal NO_x	yes	yes, D, AB
SIP annual NO_x	yes	yes

D indicates that this combination of NO_x policy baseline and restructuring policy scenario served as the benchmark in the decomposition analysis.

AB indicates that this combination of NO_x policy baseline and restructuring policy scenario served as the benchmark in the analysis of the ancillary NO_x emissions-reduction benefits of a $25 carbon tax and a $75 carbon tax.

The next two subsections describe the restructuring and the NO_x policy scenarios. In each scenario, we assume that there are no policies implemented to reduce CO_2 emissions and no changes in the regulation of sulfur dioxide (SO_2) emissions beyond those established under the 1990 Clean Air Act Amendments.

Restructuring Scenarios

Analyzing the effects of nationwide restructuring on environmental quality and emissions-control costs requires a baseline scenario with which the more comprehensive restructuring scenario can be compared. Because several regions have already restructured their electricity markets, it would be unrealistic for this baseline to assume regulated or average-cost pricing of electricity, as applied under cost-of-service regulation, in all regions. Instead, we construct a *partial restructuring* scenario to be the baseline by assuming that competitive or market-based 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 already made a commitment to implement restructuring. The schedule for transition from regulated to marginal-cost or market-based pricing under the baseline scenario is reported in Table 2 by region. In the partial restructuring scenario, no additional regions adopt market pricing over the course of the modeling horizon, which extends to 2012. All other regions are assumed to set regulated electricity prices equal to average cost.

Under time-of-day pricing, industrial customers face higher prices in peak periods and lower prices in off-peak periods than they would under regulated pricing.

The alternative economic regulatory scenario, labeled *nationwide restructuring*, assumes that restructuring is implemented across the country by 2008. As shown in the nationwide restructuring column of Table 2, three regions are assumed to implement restructuring in 2004, and the remaining five regions do so by 2008. Several features distinguish how prices are set in restructured regions. First, the retail price of electricity can be viewed as having two components: the price of generation and the price of transmission and distribution service. In regulated regions, the price of both components is set according to average embedded cost. In competitive regions, the price of generation is based on the marginal cost of generating electricity, but transmission and distribution services are still priced at average cost.[13]

Second, we assume that in all market-priced regions, utilities recover 90% of their costs of assets that are "stranded" in the transition from cost-of-service to competitive pricing. Third, 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 requiring industrial customers to face time-of-day pricing in any region that has implemented market pricing. These time-varying prices reflect the balance between supply and demand during the actual time block for which the price is being set and are not specified in advance, as are some time-of-day (or time-of-use) rates. Under time-of-day pricing, industrial customers face higher prices in peak periods and lower prices in off-peak periods than they would under regulated pricing. The price elasticity of demand for industrial customers is assumed to be -0.30, implying that a 10% increase in price in the peak periods will result in a 3% reduction in demand.[14] Since prices in off-peak periods are lower, demand is expected to rise during those time blocks under time-of-day pricing. In regulated regions, and for residential and commercial customers in all regions, the retail price is assumed not to vary between peak and off-peak times but can vary across seasons.

TABLE 2.

NERC SUBREGIONS, THE YEAR MARKET PRICING BEGINS, AND SUBREGIONS COVERED BY CAP-AND-TRADE NO*x* POLICIES UNDER MODELED SCENARIOS

NERC subregion	*Area*	*Partial restructuring begins*	*Nationwide restructuring begins*	*OTR NOx trading region*	*SIP NOx trading region*
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	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	NE
NY	NY	1999	1999	NY	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		

The fourth way that prices differ between regulated regions and those with market-determined prices is the pricing of reserve services. In all regions, after energy demand is satisfied, remaining generation capability is ordered according to going-forward fixed costs (per MW). The going-forward fixed costs include all capital costs except those for capacity already existing in 1997, fixed operation and maintenance (O&M) expenses, general and administrative (G&A) costs, and tax costs. This ordering is used as a supply schedule for reserve services. Reserve requirements are determined as a function of total demand in each region, and the required level of reserves varies by region.[15] The required reserves are met by working up the reserve supply schedule.[16]

What differs between regulated and market-priced regions is the way in which the cost of reserve services is reflected in price. In regulated regions, the fixed costs of the units providing reserve services are added to total cost of service and are automatically recovered in the price.[17]

In regions with market pricing, an equilibrium marginal price for reserve services is determined to entice services sufficient to meet the reserve requirement. This is accomplished through a simultaneous convergence in all regions and time blocks, in which the price paid for reserve services varies until equilibrium is achieved. 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 again solved. Analogously, if too many reserve services are offered, the reserve price is decreased. We also impose an incentive-compatibility constraint requiring that, in addition to those units providing reserve services, generating units that, are operating also receive the marginal reserve price plus the market-generating price. This constraint guarantees that units have no incentive to switch between generation and reserve services, as long as there is no collusion.

In addition to the method of pricing electricity, several other parameters in the model take on different values in the baseline versus the nationwide restructuring scenario (Table 3). 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 (i.e., availability) at existing generators, reductions in the heat rate at existing coal-fired generators, reductions in nonfuel operating costs, and reductions in G&A 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 market 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 market pricing and competition could spread to all regions in the future. As the number of regions committing to market pricing grows, the rate of improvement in these four parameters grows.[18] Table 3 summarizes the ratios of the values in 2008 to the values in 1997 (the base year of our data) for each variable under the two restructuring scenarios.

Our assumptions regarding how widespread restructuring is likely to affect these technical parameters are based largely on assumptions developed by the energy modelers, including ourselves, who participated in Stanford University's Energy Modeling Forum (EMF) Working Group 17 (Energy Modeling Forum 2001). In this analysis, we are more optimistic than the EMF study about improvements in plant-availability factors and slightly less optimistic about reductions in G&A costs under restructuring. Our assumptions in these areas are taken from the assumptions regarding efficiency effects developed for the "moderate restructuring" scenario in our earlier report, which we extended to 2008 (Burtraw et al. 2000).

TABLE 3. DISTINGUISHING FEATURES OF ECONOMIC REGULATION SCENARIOS IN 2008

	Economic Regulation	
	Baseline	*Nationwide restructuring*
Ratio of technical parameter values, 2008 to 1997		
Maximum availability factor	1.02	1.04
Heat rate	0.99	0.97
G&A costs	0.75	0.67
Nonfuel O&M costs	0.76	0.70
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

Two major uncertainties surrounding the future of the U.S. electricity system are how much the utilities that own transmission lines will choose to invest in expanding transmission capability and when these investments will take place. FERC has been seeking to price electricity transmission in a way that provides economic signals of the costs created by congesting the transmission grid and, at the same time, providing incentives for transmission-owning utilities to make investments that would reduce that congestion. With more open markets, there will be greater pressure to trade electricity, and presumably that pressure will be translated into expanded transmission capability. We anticipate this outcome by making different assumptions regarding transmission transfer capability between the regions in the two scenarios.[19] In the partial restructuring scenario, we assume that interregional transmission capability does not grow over time. In the nationwide restructuring scenario, we assume that by 2008, transmission capability is 10% higher.

Many restructuring policy proposals also include provisions to promote the use of renewables-based technologies (other than hydroelectric) for electricity generation. The most popular provision of this type is the renewables portfolio standard (RPS). An RPS is a requirement that a certain percentage of the electricity sold to customers must be generated using a renewables-based technology. Under an RPS, qualified generators receive credits for each MWh of electricity that they generate from renewable sources. At the end of each year, all generators that supply electricity to the market must return enough renewables credits—whether generated by their own generators, generated by generators with which they have power purchase contracts, or purchased in the renewables credit marketplace—to cover the minimum percentage of their total generation from all sources required under the standard.

With more open markets, there will be greater pressure to trade electricity, and presumably that pressure will be translated into expanded transmission capability.

RPS proposals are part of the restructuring legislation in several states, including Connecticut, Maine, and Massachusetts. RPS requirements, ranging from 3% to 7.5%, have been included in different legislative proposals for federal restructuring. Most RPS proposals exclude hydroelectric facilities.[20] We assume that an RPS is implemented in 2008 in the nationwide restructuring case, and that it 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 (MWh), slightly inflated from the $15 cap of the Clinton administration proposal. In every example we describe, the subsidy cap is binding and yields 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.[21]

NO_x Policy Scenarios

We investigate the effects of electricity restructuring under each of three sets of assumptions about NO_x policy. The first is the *OTR seasonal* NO_x policy baseline, which includes the NO_x trading program (known as Phase II) in the northeastern OTR but excludes new policies to reduce NO_x in the larger, multistate SIP Call region. The OTR seasonal NO_x policy caps emissions of NO_x at 143,000 tons for the five-month summer season (May through October) in the region. OTR comprises the Northeast and Midatlantic states, from Maryland to Maine, including the District of Columbia. The regions in our model that are included in the OTR NO_x trading program are identified in Table 2. We assume that there are no policies implemented to reduce CO_2 emissions, and no changes in the regulation of SO_2 emissions beyond those established under the 1990 Clean Air Act amendments.

The second NO_x policy scenario is labeled *SIP seasonal*, and it corresponds to EPA's proposed NO_x SIP Call program, described in Chapter 2. This scenario extends the geographic scope of the OTR seasonal NO_x cap-and-trade program, while limiting NO_x emissions to the same average rate, 0.15 pounds per MMBtu, as the OTR program. This scenario includes a five-month summer ozone program implemented in the eastern states, represented by the regions in the Haiku model that are approximately equal to the SIP region.[22] The included regions are identified in the last column of Table 2. The emissions cap under this policy is 444,300 tons per summer season within the SIP region, compared with an emissions level of 1.445 million tons in the baseline in year 2008.[23]

The third NO_x policy baseline is *SIP annual*. Here, the average emissions rate achieved during the five-month summer season for the SIP region is extended to year-round. The annual emissions cap under this policy is 1.06 million tons per year within the SIP region, compared with an emissions level of 3.449 million tons in the baseline in year 2008.

In both SIP scenarios, we assume the policy is announced in 2001 and implemented in 2004. We report results for 2008, hoping thereby to avoid the transitional difficulties that may follow implementation in the first years of the program.

Sensitivity Analysis

The transition from the baseline (partial restructuring) scenario to the nationwide restructuring scenario is characterized by a change from regulated to market-based pricing in many regions, and by changes in the values of several parameters in the model, all of which are described in Table 3 above. The main analysis presented here shows how the combined changes in all these factors are likely to affect generation, investment, prices, and emissions in the electricity sector. Because these scenarios are largely driven by assumptions about which there is a great deal of uncertainty, it is useful to understand which assumptions are the important drivers of the results.

We want to better understand how changes in specific assumptions in the model contribute to the overall changes in prices, generation, and emissions of NO_x and carbon resulting from more widespread restructuring. To do so, we perform a series of model runs that "decompose" the effects of different aspects of nationwide restructuring on predicted variables into the contribution from changes in specific model parameters (or groups of parameters) and the contributions attributable to the change from regulated to market pricing. In each model run, we do a modified version of the nationwide restructuring scenario, in which we assume all parameter values except one are the same as under nationwide restructuring. Thus, for example, to determine the effect of the transmission growth assumption on our findings, we compare the results of the complete nationwide restructuring scenario with another scenario in which the growth rate of transmission capability is set at baseline levels and all other parameters remain unchanged from their levels under nationwide restructuring. We perform this parameter decomposition for all the parameters identified in Table 3. We also construct a scenario in which we set those parameter values, at their base case values, while still allowing for market pricing with time-of-day pricing for industrial customers in all regions. In all of these analyses, we assume that the SIP seasonal NO_x policy holds.

■ ■ ■

CHAPTER FOUR

Results

In the first subsection below, we review the results regarding the effects of nationwide restructuring on total generation, the mix of fuels used to generate electricity, and electricity price. In the second subsection, we review the effects of restructuring on emissions of NO_x and carbon from the electricity sector. Both sections focus on effects within the Midatlantic or MAAC region, the broader SIP-Call region, and at the national level. The particular focus on the Midatlantic region provides some insight into changes in emissions that are in close proximity to the Washington, DC region, an area struggling to comply with the National Ambient Air Quality Standards for ozone (to which NO_x emissions are a contributing factor), and to the particularly sensitive Chesapeake Bay watershed.

Generation and Price

Two important determinants of the level of NO_x and carbon emissions from the electricity generation sector are the total quantity of electricity output and the mix of fuels used to generate electricity. With all else equal, higher levels of electricity production tend to be associated with higher levels of emissions. Changes in fuel mix can either exacerbate or mitigate this problem, depending on whether the shift is toward more or less use of coal. Below, we discuss the effects of more widespread electricity restructuring on total generation, mix of fuels used for generation, and electricity price in MAAC, in the broader SIP Call region, and across the nation in the year 2008.

With all else equal, higher levels of electricity production tend to be associated with higher levels of emissions.

Table 4 presents the generation and price results for MAAC. The table is divided into three sections, one for each NO_x policy scenario. The first row in each section presents the level of emissions under the partial restructuring baseline in conjunction with the relevant NO_x policy scenario. The second row presents the differences from the baseline under nationwide restructuring for the assumed NO_x policy. A similar format is adopted for most of the subsequent tables.

The average electricity price in MAAC falls 4.5% in the baseline and 1.3% in the SIP seasonal case and goes up 0.5% in the SIP annual case with the shift to nationwide restructuring. Under the SIP annual policy, the price in MAAC rises with nationwide restructuring because an increase in the cost of reserves (associated with older units with higher, fixed costs that are called into service) more than offsets the reduction in generation price (associated with greater reliance on imports within MAAC). Within the MAAC region under the two seasonal NO*x* policies, residential and commercial consumers see bigger absolute price declines from nationwide restructuring than do industrial customers. Note that since MAAC is restructured under the baseline scenario, these price effects in MAAC are not the result of restructuring within MAAC, but are instead the result of more widespread restructuring in surrounding regions (including more transmission capacity). More trading with outside regions could help lower prices in peak periods, which could have a disproportionate effect on residential consumers, who tend to have a larger share of their consumption during peak periods than do other classes of customers. Lower prices in MAAC lead to higher electricity demand, but generation in MAAC actually falls and is replaced by substantially higher imports. The composition of generation within MAAC becomes more coal-intensive as the generation displaced by imports is largely from newly built gas-fired facilities. Coal-generation, however, falls only slightly.

TABLE 4.

GENERATION BY FUEL AND ELECTRICITY PRICE IN MAAC REGION UNDER BASELINE SCENARIO AND CHANGE DUE TO RESTRUCTURING UNDER DIFFERENT NO*x* POLICIES FOR 2008

Policy scenario	*MAAC regional generation (million MWh)*			*MAAC regional price ($1997/MWh)*
	COAL	GAS	TOTAL	
OTR baseline NO*x*				
Baseline	88	131	315	77.4
Nationwide restructuring	0	- 42	- 41	- 3.5
SIP seasonal NO*x*				
Baseline	83	135	314	74.9
Nationwide restructuring	- 2	- 38	- 34	- 1.0
SIP annual NO*x*				
Baseline	101	125	308	76.3
Nationwide restructuring	- 18	- 20	- 40	+ 0.4

The stronger preference for coal over gas under nationwide restructuring is even more pronounced in the SIP Call region, as shown in Table 5. Coal-fired generation in the region increases by 11% to 14% and gas-fired generation declines by 22% to 25% as a result of restructuring. The extent of the shift from gas to coal resulting from restructuring depends on the stringency of the NO*x* policy; more comprehensive NO*x* policies lead to a smaller shift from gas to coal. However, even with an annual NO*x* cap, gas generation in the SIP Call region falls more than 20% as a result of restructuring.

Restructuring leads to at least a 3% reduction in average electricity price in the SIP Call region under all NO*x* policies. In this broader region, industrial customers tend to benefit more from restructuring than do commercial or residential customers. Absolute price declines as a result of widespread restructuring are generally four times larger for industrial customers than for residential customers, and two times larger than for commercial customers. This price reduction leads to a 1.0% to 1.2% increase in aggregate electricity demand across the cases. However, total electricity generation in the region increases by roughly 2% as the region as a whole increases its net exports to other regions.

Table 5 also reveals an interesting finding about the effect of more stringent NO*x* policies on the price of electricity. Under nationwide restructuring and the OTC NO*x* policy, baseline electricity price in the SIP region is $61.60 per MWh (calculated as 64.4 minus 2.8 in Table 5). Under the SIP seasonal policy, the price rises to $62.50, which is nearly $1 per MWh greater. Extending the NO*x* policy to the SIP annual policy raises the price by just $0.3 per MWh, to $62.80.

The results show that an expanded NO_x policy will not necessarily lead to a significant increase in electricity prices. It is instructive to examine how extending a regional NO_x policy from a seasonal to an annual basis could have a negligible or possibly negative effect on electricity prices. One reason is that the emissions allowance price is dramatically less under an annual policy because the cost of NO_x control, including capital cost, can be divided over a greater quantity of emissions reductions to achieve a lower cost-per-ton reduced. The cost-per-ton reduced at the margin determines allowance price, which directly enters the calculation of the variable cost of electricity generation.

The second reason that the effect on price may be negligible has to do with changes in generation capacity, and with how the cost of capacity is reflected in electricity price. Slightly more than half of the generation in the SIP Call region is in areas characterized by regulated pricing in the baseline, under which capital and variable costs are annualized and spread over total sales to calculate the price of electricity. In these areas, introducing an environmental policy that increases the costs of electricity supply leads directly to an increase in the electricity price.

The other part of generation in the SIP Call region is in the market-pricing areas, where the electricity price is determined by the variable cost of the marginal generator plus the incremental capital cost of the marginal reserve unit. Policies that change the relative costs of facilities affect which facility is at the margin (and thereby prices) and the revenues earned by each facility (and thereby the policies affect capacity investment and retirement). In these areas, a new environmental policy that increases the costs of electricity supply may lead to an increase or a decrease in the electricity price.

TABLE 5.

GENERATION BY FUEL AND ELECTRICITY PRICE IN THE SIP CALL REGION UNDER BASELINE SCENARIO AND CHANGE DUE TO RESTRUCTURING UNDER DIFFERENT NO_x POLICIES FOR 2008

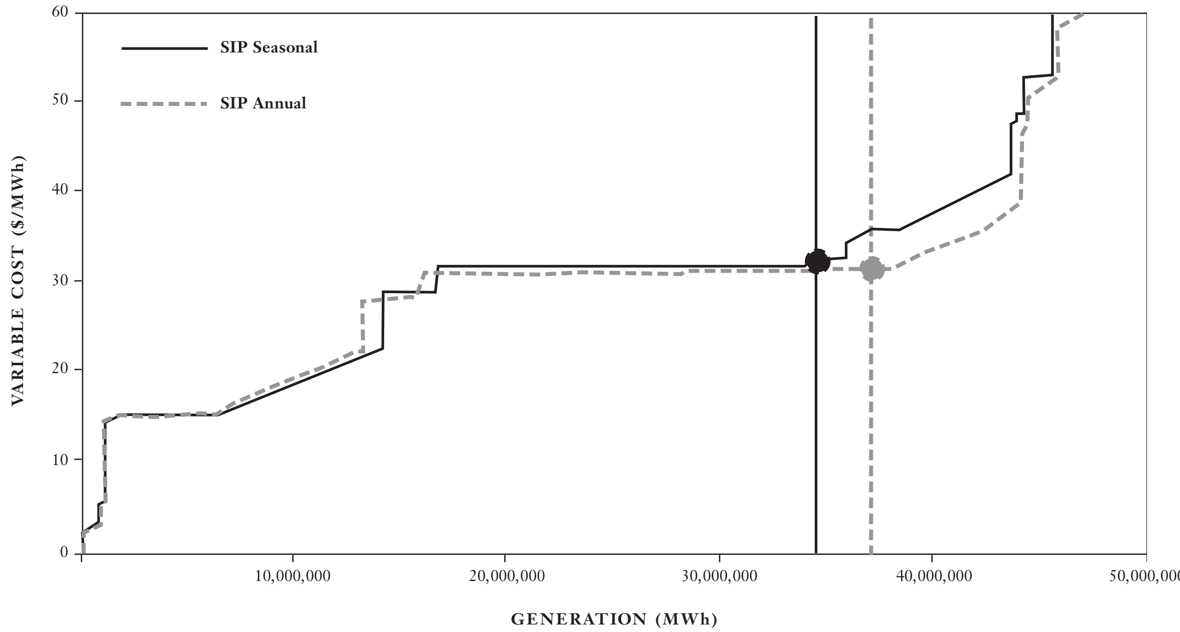
Policy scenario	*SIP regional generation (million MWh)*			*SIP regional price ($1997/MWh)*
	COAL	GAS	TOTAL	
OTR baseline NO_x				
Baseline	1,095	460	2,139	64.4
Nationwide restructuring	+ 157	- 116	+ 45	- 2.8
SIP seasonal NO_x				
Baseline	1,076	464	2,119	65.1
Nationwide restructuring	+ 149	- 116	+ 43	- 2.6
SIP annual NO_x				
Baseline	1,106	441	2,132	64.9
Nationwide restructuring	+ 123	- 97	+ 30	- 2.1

Figure 1 illustrates a case in which the extension from the SIP seasonal to SIP annual policy reduces the electricity price. The figure depicts the determination of marginal generation cost in a baseload time block in summer 2008 for New England, a market-pricing region. The baseload time block includes 70% of the hours in the season, and thus this supply curve is the relevant one for most of the summer. The solid upward-sloping line is the schedule of variable generation costs for the SIP seasonal scenario, and the dashed upward-sloping line is the schedule for the SIP annual scenario. The variable cost of a representative unscrubbed coal plant, using a particular type of coal, is represented by the point indicated on each supply curve.

The latter half of the curve for the SIP annual scenario lies generally below and to the right of the curve for the SIP seasonal scenario. This repositioning implies that for a given level of generation, the variable generation cost under an annual pollution program is less than under a seasonal program. This is true in part because the price of an emissions allowance is less un-

FIGURE 1.

THE SCHEDULE OF VARIABLE GENERATION COSTS FOR THE NEW ENGLAND NERC SUBREGION IN BASE-LOAD TIME BLOCK IN SUMMER 2008



der the annual program. The price of an allowance (equivalent to the marginal cost of abatement) falls from $3,401 per ton in 2008 in the SIP seasonal scenario to $1,985 in the SIP annual scenario. The small vertical difference between the points representing the unscrubbed coal plant results from the small reduction in variable cost for that plant. However, one can observe other parallel portions of the two curves that indicate a greater reduction in costs for some other plants.

The shift of the marginal cost curve to the right in the SIP annual scenario—indicated, for example, by the shift in the point representing the unscrubbed coal plant—results from a change in the variable-cost ordering among plants and a change in capacity. The unscrubbed coal plant, indicated by the points, has been pushed back in the variable-cost ordering for electricity generation. The shift is due to the addition of new combined-cycle capacity, which has lower variable costs and appears earlier in the variable cost ordering for electricity generation. The vertical lines in Figure 1 represent the generation of electricity during the time block. Generation increases as marginal generation cost falls in moving from the SIP seasonal to the SIP annual scenario. When taking into account the effect in all time blocks, the net effect on electricity price is less than would be anticipated if all costs were passed through to ratepayers, as occurs in regulated regions.

Table 6 is the national analog of Tables 4 and 5. It shows that the shift from gas to coal, resulting from restructuring, is also a national phenomenon. Comparing Tables 5 and 6 illustrates that most of the additional coal generation is occurring in the SIP Call region, which is consistent with the overlap between this region and major load centers in the eastern United States and with the location of much of the existing U.S. coal-fired capacity. Table 7, which reports the effect of nationwide restructuring on coal, gas, and total capacity, shows that nationwide restructuring leads to very little change in coal-fired capacity and a roughly 33% drop in gas capacity. Therefore, most of the additional coal generation comes from more intensive use of existing coal capacity, and so it is not surprising that much of the increment is found in the SIP Call region.

Table 6 also shows that nationwide restructuring results in a 2.5% decline in national average price under an OTR seasonal NO_x policy, and a 2.1% drop under the SIP annual NO_x policy. As in the SIP region, industrial customers see the largest price declines as a result of restructuring. Commercial customers face somewhat smaller drops in prices, and the price declines for residential customers are fairly small, ranging from 0.1 mills under the SIP annual NO_x policy to 1.0 mills under the OTR NO_x policy baseline. Total national generation increases by 0.3% to 0.6% across the three NO_x policy baselines. Comparing Tables 4, 5, and 6 shows that the average electricity price reduction that results from nationwide restructuring is more pronounced in the SIP region.

Although restructuring clearly has a big impact on the fuel composition of generating capital and actual generation, our simulations also show a substantial effect on the overall level of generating capacity in the industry. Table 7 shows that total capacity in the industry falls by approximately 11% with more widespread restructuring. This happens because the need for peak capacity declines dramatically as a result of time-of-day pricing for industrial customers. These customers substantially reduce their demand during peak periods in response to high prices, thus reducing the need for both generating and reserve capacity. The size of the capacity response here depends importantly on our assumption about the elasticity of demand for industrial customers. If peak-period industrial demand proves less responsive to increases in peak-period prices than the -0.3 demand elasticity assumed here, the drop in capacity will be less than the 10% that we find.

In addition to the improvements in the efficiency of coal-fired generation that help spur a shift from gas to coal, nationwide restructuring also includes a national renewables portfolio stan-

TABLE 6.

GENERATION BY FUEL AND ELECTRICITY PRICE IN THE NATION UNDER BASELINE SCENARIO AND CHANGE DUE TO RESTRUCTURING UNDER DIFFERENT NO_x POLICIES FOR 2008

Policy scenario	*National generation (million MWh)*			*National price ($1997/MWh)*
	COAL	GAS	TOTAL	
OTR baseline NO_x				
Baseline	1,767	1,182	3,996	62.2
Nationwide restructuring	+ 230	- 221	+ 24	- 1.6
SIP seasonal NO_x				
Baseline	1,759	1,221	3,997	62.0
Nationwide restructuring	+ 213	- 260	+ 23	- 1.3
SIP annual NO_x				
Baseline	1,784	1,203	4,010	62.1
Nationwide restructuring	+ 187	- 241	+ 9	- 1.3

dard with a price cap of $17 per mWh. Although the RPS policy that is bundled with the nationwide restructuring scenario generally results in higher renewables generation nationwide, Table 8 reveals one notable exception. Despite the RPS policy, nationwide restructuring results in a near halving of nonhydro renewable generation in the SIP Call region under the OTR baseline NO_x policy in 2008. In this case, increased generation from existing coal-fired facilities under nationwide restructuring is displacing renewables generation in the SIP region, and the incremental renewables generation taking place in response to the RPS policy is largely occurring in the western regions. Thus, this decline is largely indicative of a regional shift.

It is also notable that baseline renewables generation in the SIP region is lower under the more stringent NO_x policies, but under these policies nationwide restructuring leads to greater use of renewables within the SIP region. The reduction in renewables use, associated with going from an OTR seasonal NO_x policy to a SIP seasonal NO_x policy, follows from a somewhat complicated chain of interactions in the model. More stringent NO_x policies make new gas plants more attractive relative to existing coal plants, which have higher NO_x emissions. As a result, more new gas-fired generators are built, and these plants crowd out construction of new renewables. New gas-fired, combined-cycle generators have low operating costs and so once they are constructed and running, they will reduce the need for generation from other sources, including new renewables.

Nationwide, nonhydro renewables generation increases by 50% as a result of nationwide restructuring under the OTR seasonal NO_x policy. Under the two SIP policies, renewables generation nationwide is substantially lower than under the OTR seasonal NO_x policy. Because the SIP policies make coal generation more expensive, demand for coal falls in the SIP Call region. This reduction in demand lowers the price of coal both inside and outside the SIP Call region. Lower fuel costs mean that existing coal-fired plants run more, and crowd out new wind generation that would otherwise be built under the less restrictive OTR seasonal NO_x policy. Adding an RPS policy more than doubles the nonhydro renewables generation, enough to almost make up for the loss associated with the introduction of the SIP policy.

TABLE 7.

NATIONWIDE GENERATION CAPACITY BY FUEL IN BASELINE AND CHANGE DUE TO RESTRUCTURING UNDER DIFFERENT NO_x POLICY SCENARIOS FOR 2008 (THOUSAND MW)

	COAL	GAS	TOTAL
OTR baseline NO_x			
Baseline	322.5	283.8	875.9
Nationwide restructuring	+ 1.5	- 94.5	- 97.4
SIP seasonal NO_x			
Baseline	322.4	294.3	876.2
Nationwide restructuring	+ 2.0	- 103.3	- 100.0
SIP annual NO_x			
Baseline	321.2	290.9	875.1
Nationwide restructuring	+ 1.9	- 93.3	- 95.9

TABLE 8.

NONHYDRO RENEWABLES GENERATION BY REGION IN BASELINE SCENARIO AND CHANGE DUE TO RESTRUCTURING UNDER DIFFERENT NO_x POLICY SCENARIOS FOR 2008 (MILLION MWH)

Policy scenario	*National generation*	*National price*
OTR baseline NO_x		
Baseline	9	58
Nationwide restructuring	- 4.0	- 28
SIP seasonal NO_x		
Baseline	3	37
Nationwide restructuring	+ 2.0	- 46
SIP annual NO_x		
Baseline	4	38
Nationwide restructuring	+ 1.0	+ 45

Emissions

The main focus of this report is the effects of electricity restructuring on emissions of NO_x and carbon from the electricity-generating sector. The emissions effects are determined by the combination of the total amount and mix of generation by fuel type, reported above, and in the case of NO_x, by the stringency and geographic and temporal scope of NO_x policy.

The results of our analysis for NO_x emissions, reported in Table 9, suggest that nationwide restructuring will lead to higher emissions of NO_x, both in the SIP Call region and across the nation. However, it also suggests that the incremental emissions in the SIP Call region associated with restructuring could be eliminated by an annual NO_x cap-and-trade program in the region. Nationwide restructuring generally reduces NO_x emissions in MAAC because, under this scenario, the region relies to a greater extent on imported power. Nationwide restructuring causes annual NO_x emissions to grow by over 12% in the SIP Call region under an OTR seasonal NO_x policy, but the total tonnage of incremental NO_x emissions from nationwide restructuring is cut by 40% under a SIP seasonal NO_x policy. With a SIP annual NO_x policy, nationwide restructuring has essentially no effect on annual NO_x emissions in the SIP Call region. Nationwide, the increase in annual NO_x emissions due to nationwide restructuring falls from roughly 567,000 tons under the OTR seasonal policy to 112,000 tons with a SIP annual policy. That is, under all NO_x policy regimes, restructuring causes an increase in NO_x, but the increase is dramatically lower under the SIP annual approach.

A more detailed breakdown of the effects of restructuring on regional NO_x emissions from the electricity sector is provided in Figures 2, 3, and 4. Figure 2 shows that restructuring actually leads to lower emissions in MAAC, NY, and NE, but to higher emissions in the regions immediately to the west and south of MAAC. Restructuring also leads to lower emissions in California because that region relies more on power imports from NWP. Under the SIP seasonal NO_x policy, the results, shown in Figure 3, appear similar, although the changes in emissions (both decreases and increases) due to restructuring tend to be smaller. Under a SIP annual policy, emissions within the SIP region clearly shift to the Midwest with restructuring. Emissions in the STV region decline slightly, as shown in Figure 4.

TABLE 9.

ANNUAL NO_x EMISSIONS BY REGION IN BASELINE SCENARIO AND CHANGE DUE TO RESTRUCTURING UNDER DIFFERENT NO_x POLICY SCENARIOS FOR 2008 (THOUSAND TONS)

Policy Scenario	*MAAC*	*SIP Call region*	*Nationwide*
OTR baseline NO_x			
Baseline	252	3,449	5,533
Nationwide restructuring	- 18	+ 417	+ 567
SIP seasonal NO_x			
Baseline	227	2,418	4,541
Nationwide restructuring	- 1.0	+ 254	+ 369
SIP annual NO_x			
Baseline	201	1,041	3,155
Nationwide restructuring	- 22	+ 7.0	+ 112

The effects of different NO_x policies on regional emissions under the nationwide restructuring scenario are illustrated in Figures 5, 6, and 7. Figure 5 shows that the switch from an OTC seasonal NO_x policy to a more geographically comprehensive SIP seasonal policy has only a small effect on NO_x emissions in the Northeast but a more substantial effect in the midwestern regions of MAIN and ECAR, and in STV. Emissions in the regions bordering the SIP region, including MAPP and SPP, rise slightly as a result of the policy, and the bulk of these increases occur in the summer season. Figure 6 shows NO_x emissions fall substantially in the

FIGURE 2.

CHANGE IN ANNUAL NO_x EMISSIONS BY REGION DUE TO NATIONWIDE RESTRUCTURING UNDER OTR SEASONAL NO_x POLICY

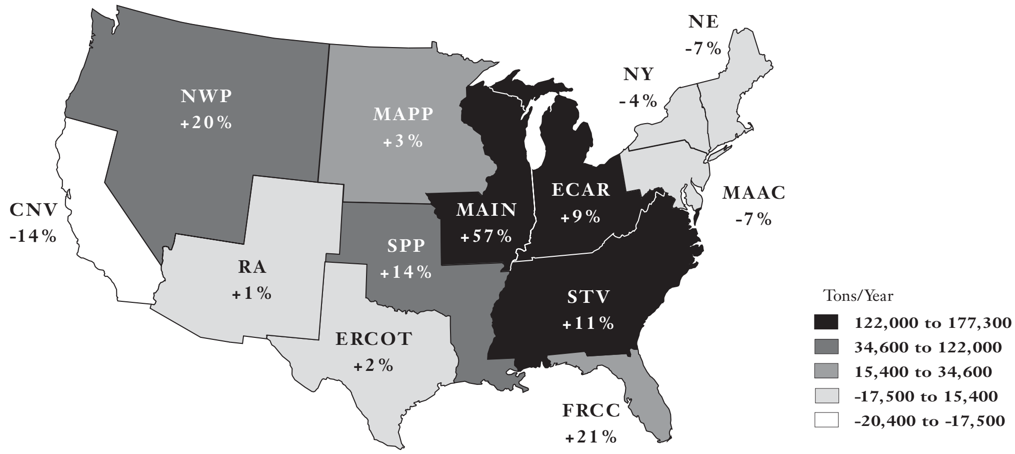


FIGURE 3.

CHANGE IN ANNUAL NO_x EMISSIONS BY REGION DUE TO NATIONWIDE RESTRUCTURING WITH SIP SEASONAL NO_x POLICY

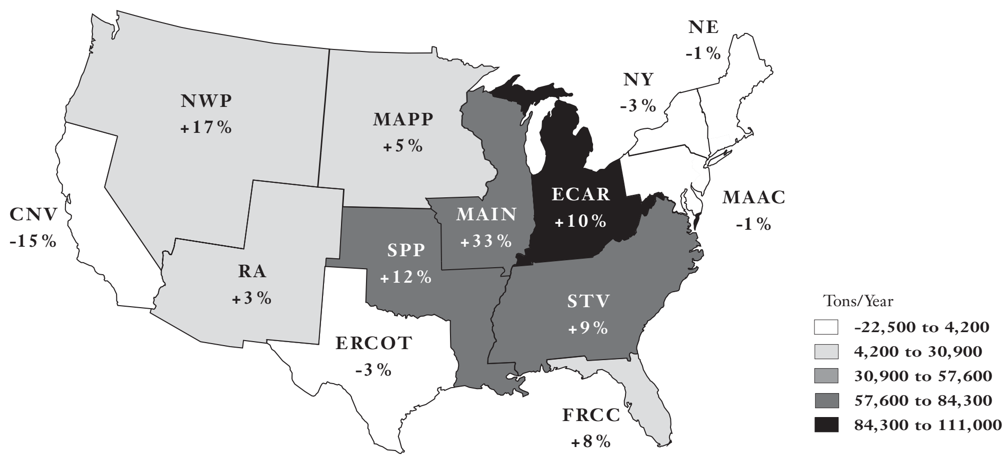


FIGURE 4.

CHANGE IN ANNUAL NO_x EMISSIONS BY REGION DUE TO NATIONWIDE RESTRUCTURING UNDER SIP ANNUAL NO_x POLICY

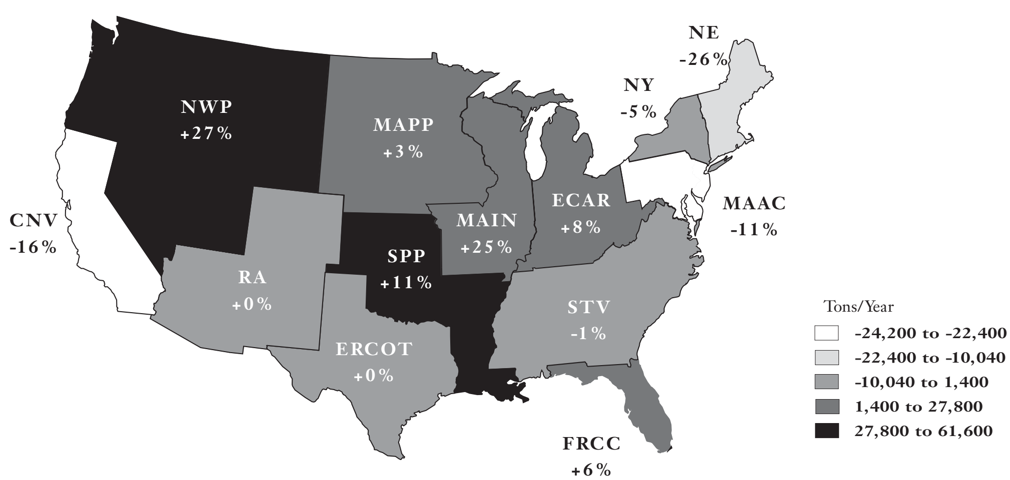
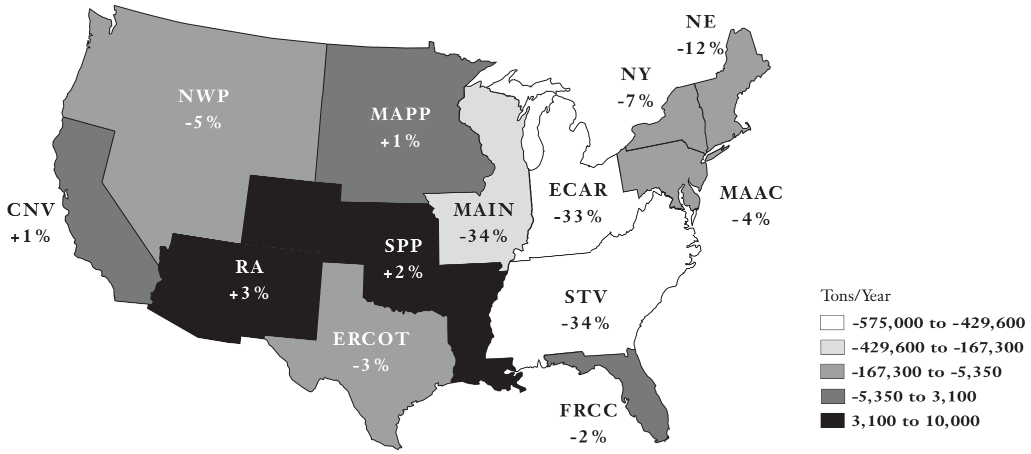
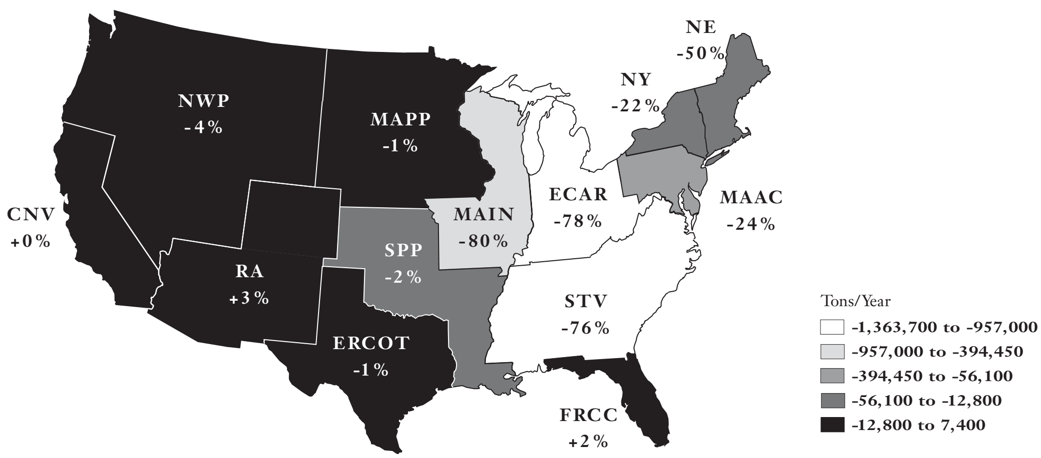


FIGURE 5.



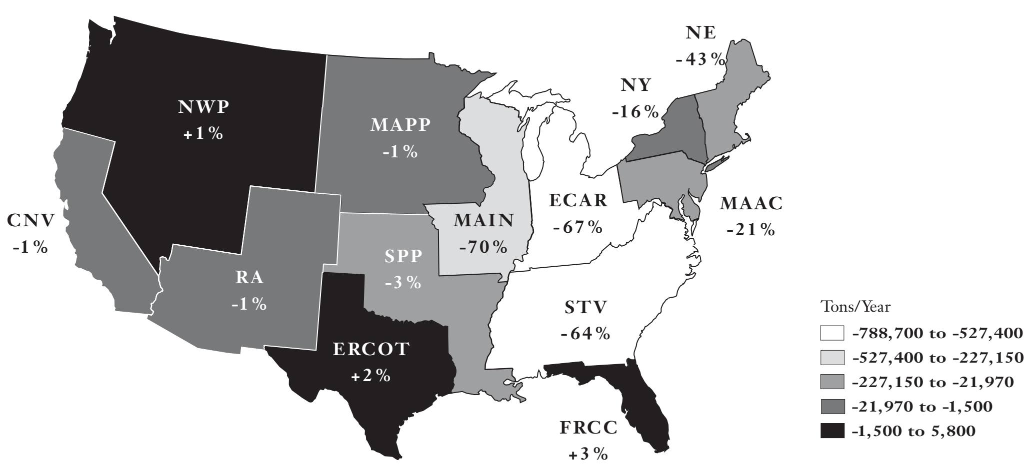
CHANGE IN ANNUAL NO_x EMISSIONS BY REGION WITH SHIFT FROM OTR SEASONAL NO_x POLICY TO SIP SEASONAL NO_x POLICY UNDER NATIONWIDE RESTRUCTURING

FIGURE 6.



CHANGE IN ANNUAL NO_x EMISSIONS BY REGION WITH SHIFT FROM OTR SEASONAL NO_x POLICY TO SIP ANNUAL NO_x POLICY UNDER NATIONWIDE RESTRUCTURING

FIGURE 7.



CHANGE IN ANNUAL NO_x EMISSIONS BY REGION WITH SHIFT FROM SIP SEASONAL NO_x POLICY TO SIP ANNUAL NO_x POLICY UNDER NATIONWIDE RESTRUCTURING

TABLE 10.

ANNUAL CARBON EMISSIONS BY REGION IN BASELINE SCENARIO AND CHANGE DUE TO RESTRUCTURING UNDER DIFFERENT NO_x POLICY SCENARIOS FOR 2008 (MILLION METRIC TONS)

Policy Scenario	*MAAC*	*SIP Call*	*Nationwide*
OTR baseline NO_x			
Baseline	40.3	371.5	660.8
Nationwide restructuring	- 5.1	+ 8.1	+ 34.2
SIP seasonal NO_x			
Baseline	39.2	366.8	664.2
Nationwide restructuring	- 4.0	+ 5.8	+ 25.6
SIP annual NO_x			
Baseline	42.9	375.4	671.0
Nationwide restructuring	- 9.1	+ 17.9	+ 18.1

Midwest with the shift from the OTR seasonal policy to the SIP annual policy. The change to an annual NO_x policy in the SIP region has very little impact on emissions in neighboring regions, suggesting that the policy does not produce an increase in NO_x emissions in unregulated regions. Figure 7 provides a regional breakdown of the incremental change from a SIP seasonal to a SIP annual NO_x policy. Here again, we see that the biggest drops in emissions occur in the Midwest and that emissions in regions that border the SIP region also tend to fall slightly with the change in policy.

Table 10 is a summary of the effects of nationwide restructuring on carbon emissions from the electricity sector in the three regions. Consistent with the reductions in both coal-fired and total generation in MAAC under nationwide restructuring, emissions of carbon in MAAC also fall as a result of more widespread restructuring. In the larger SIP Call region, carbon emissions tend to increase by 18 million to 28 million metric tons, depending on the NO_x policy scenario. Because NO_x emissions are reduced largely through the use of postcombustion controls, adding more stringent NO_x reduction policies does little to reduce emissions of carbon.

At the national level, carbon emissions rise by 2.7% to 5.1% with nationwide restructuring, depending on the NO_x policy regime. Carbon emissions increases, caused by nationwide restructuring, are slightly lower with the SIP NO_x policies, and most of the national increases occur within the SIP Call region.

Cost of Pollution Control

Table 11 is a summary of the cost of postcombustion control per ton of emissions reductions achieved under the policy scenarios at all generating units in the SIP Call region. The table reports both marginal and average costs. Marginal cost is equivalent to the predicted price for an emissions allowance, and average cost is calculated as the ratio of the total cost of postcombustion controls divided by the total change in emissions, during the relevant season, at all units in the SIP Call region.

Under the OTR seasonal NO_x policy, nationwide restructuring has a small effect on the marginal cost of a NO_x permit in the OTR region. No average cost information is available for this NO_x scenario: because it is the baseline, it cannot be compared with anything to calculate the change in emissions. Under the SIP seasonal policy, the marginal cost of NO_x reductions falls by $31 per ton as a result of nationwide restructuring and the average cost rises by $326 per ton.

Under the SIP annual NO_x policy, both average and marginal costs of NO_x control are substantially below the levels observed under a seasonal NO_x policy for the partial restructuring base case. The ability to reduce per-unit costs by using capital-intensive pollution controls throughout the course of the year, instead of just during the summer, lowers substantially the marginal cost of reducing a single ton. Under an annual SIP policy, the average cost of NO_x control rises by $62, or 5.5%, and the marginal cost falls by $184, or 9.3%, as a result of nationwide restructuring. Higher total levels of emissions reductions are necessary to meet the regional emissions target because of more intensive use of coal-fired generation with nationwide restructuring.

Figure 8 shows how the marginal NO_x control cost curve for the SIP region, under an annual SIP policy, changes with nationwide restructuring. Because of greater coal use, in the absence of the SIP annual policy, the amount of total NO_x emissions reductions required to achieve the cap is higher with nationwide restructuring than under partial restructuring. The quantities to be reduced are illustrated by the vertical lines. However, because the model plant that determined the marginal cost of control, an unscrubbed coal plant in New England, operates more under nationwide restructuring, there are more tons of NO_x to be removed over the course of the year. This means that the annual capital costs associated with the NO_x control equipment, in this case selected catalytic reduction (SCR), can be spread over more tons, and thus the marginal control cost is less under nationwide restructuring than under partial restructuring. This lower marginal cost is a result of spreading the capital cost over a greater number of kWh. Consequently, this model plant shifts back in the schedule of marginal cost of control, and controlled units shift back in the schedule of marginal cost of generation. So we have two counteracting effects, and we observe that the lowering of the marginal cost curve dominates the increased number of reductions required, yielding a lower marginal cost of NO_x control. As a result, a different technology becomes marginal, and the marginal cost of control and, equivalently, the market price of NO_x allowances fall.

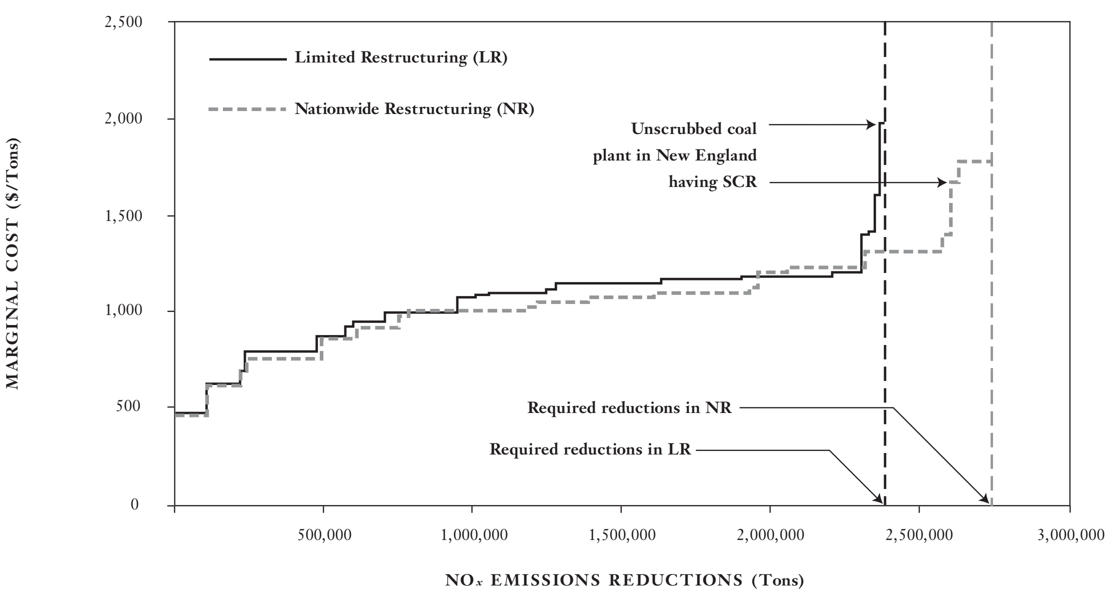
TABLE 11.

COST OF ADOPTING POSTCOMBUSTION CONTROL PER TON OF NO_x REDUCTION FOR 2008 FOR THE SIP CALL REGION ($1997)

Policy scenario	*Average*	*Marginal*
OTR baseline NO_x		
Baseline	—	1,356
Nationwide restructuring	—	- 22
SIP seasonal NO_x		
Baseline	2,112	3,401
Nationwide restructuring	+ 326	- 31
SIP annual NO_x		
Baseline	1,133	1,985
Nationwide restructuring	+ 62	- 184

FIGURE 8.

REQUIRED EMISSIONS REDUCTIONS AND SCHEDULE OF MARGINAL COSTS OF CONTROL FOR SIP ANNUAL POLICY IN THE SIP REGION UNDER PARTIAL RESTRUCTURING AND NATIONWIDE RESTRUCTURING FOR 2008



CHAPTER FIVE

Sensitivity Analysis

We perform two types of sensitivity analysis to test the implications of certain assumptions for our results. The decomposition sensitivity analysis allows us to identify the importance of individual assumptions and groups of assumptions in determining the effect of nationwide restructuring on particular model outputs. We also perform a sensitivity analysis to examine the effects of eliminating time-of-day pricing of electricity for industrial customers.

Decomposition Sensitivity

The transition from the baseline (partial restructuring) scenario to the nationwide restructuring scenario is characterized by a change from regulated to market-based pricing in many regions and by changes in the values of several parameters in the model, all of which are described in Table 3 above. The main analysis presented here shows how the combined changes in all these factors are likely to affect generation, investment, prices, and emissions in the electricity sector. Because these scenarios are largely driven by assumptions about which there is a great deal of uncertainty, it is useful to understand which assumptions are the important drivers of the results.

To better understand how changes in specific assumptions in the model contribute to the overall changes in prices, generation, and emissions of NO_x and carbon resulting from more widespread restructuring, we perform a series of model runs that "decompose" the effects of different aspects of nationwide restructuring on predicted variables into the contribution from changes in specific model parameters (or groups of parameters) and the contributions attributable to the change from regulated to market pricing. In each model run, we do a modified version of the nationwide restructuring scenario in which we assume all parameter values, except one, are the same as under nationwide restructuring. Thus, for example, to determine the effect of the transmission growth assumption on our findings, we compare the results of the complete nationwide restructuring scenario with another scenario in which the growth rate of transmission capability is set at baseline levels and all other parameters remain unchanged from their levels under nationwide restructuring. We perform this parameter decomposition for all the parameters identified in Table 3. We also construct a scenario in which we set those parameter values at their base case values while still allowing for market pricing with time-of-day pricing for industrial customers in all regions. In all of these analyses, we assume that the SIP seasonal NO_x policy holds.

Throughout this report, we have defined the effect of more widespread restructuring on different variables as the difference between the value obtained in the nationwide restructuring scenario and the value obtained under partial restructuring. The decomposition analysis allows us to determine what portion of that difference is due to the technological assumptions (listed in Table 3) that distinguish nationwide restructuring from partial restructuring and what portion is due to the change from regulated to market pricing of electricity. We consider both the individual contribution of specific assumptions and the contribution of all of the assumptions together, or the *collective parameter assumptions.* Throughout this discussion of the decomposition results, we also refer to the change from regulated to market pricing, holding the productivity assumptions fixed at baseline levels, as the change in *pricing regime.*

Table 12 is a summary of the findings from the decomposition analysis. The first column presents the results for prices, total generation and generation by fuel, and emissions under nationwide restructuring. Columns 2 through 6 report differences from the nationwide restructuring case when individual parameter assumptions are set at the levels that apply under partial restructuring. Thus, for example, when the nationwide restructuring scenario is run without a renewables portfolio standard, the price of electricity is $0.05 per MWh lower than it is in the full, nationwide restructuring case. Column 7 shows the differences from the nationwide restructuring case under a scenario with no RPS, no transmission growth, and none of the accelerated productivity changes that are assumed to accompany nationwide restructuring. The difference between the results of this scenario and the nationwide restructuring scenario shows the effect of the collective parameter assumptions. The difference between the results of this sce-

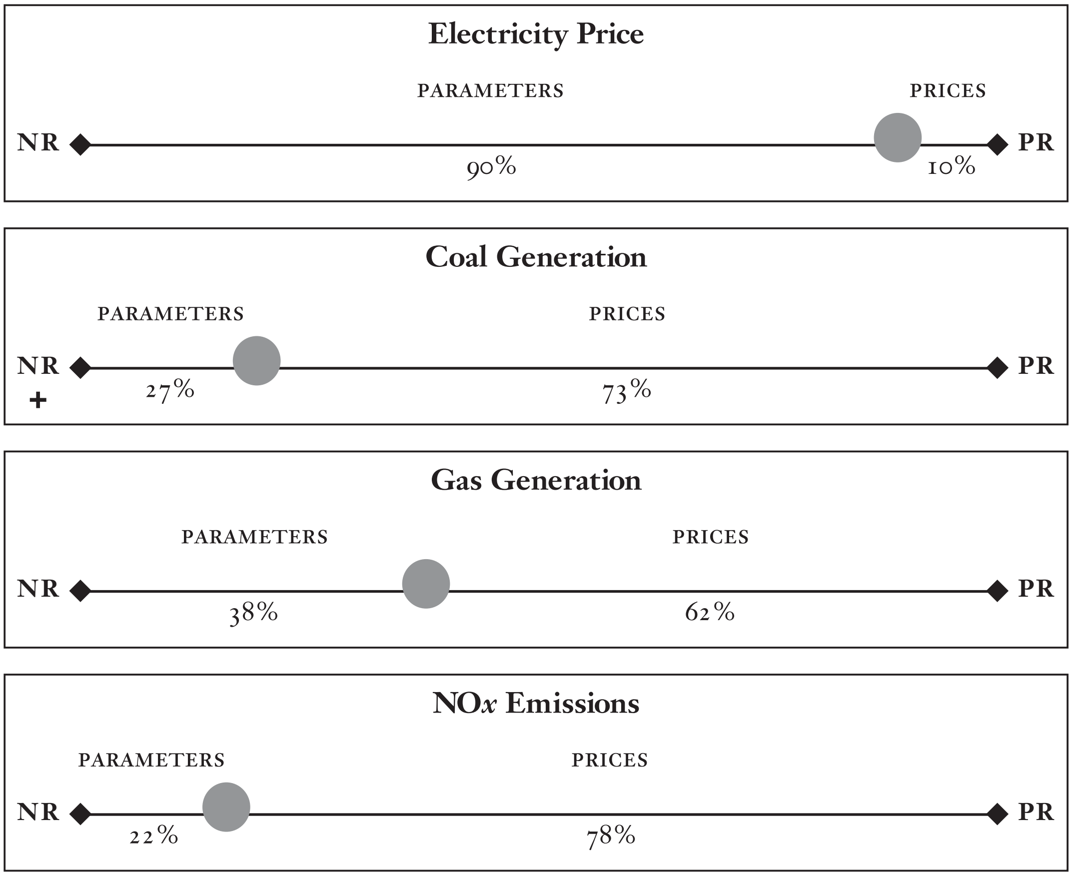
TABLE 12.

PRICE, GENERATION, AND EMISSIONS RESULTS UNDER BASELINE AND NATIONWIDE RESTRUCTURING WITH SIP SEASONAL NO_x POLICY AND CHANGES UNDER DIFFERENT DECOMPOSITION ASSUMPTIONS FOR THE UNITED STATES IN 2008

	1	2	3	4	5	6	7	8
	Nationwide restructuring (NR)	*NR with no RPS*	*NR with no transmission growth*	*NR with slower availability factor improvement*	*NR with slower heat rate improvement*	*NR with slower O&M and G&A cost improvement*	*NR with no RPS, transmission growth, or productivity change*	*Partial restructuring (PR)*
Price ($/MWh)	60.7	−0.05	−0.83	+0.01	−0.64	+0.22	+1.17	62.0
Total generation (billion kWh)	4,020	+1	+18	−2	+22	−8	−14	3,997
Coal	1,972	+22	−16	−37	−8	−29	−57	1,759
Gas	961	+23	+38	+51	+30	+24	+100	1,221
Nonhydro renewables	83	−46	−1	−1	+1	−1	−40	37
NO_x emissions (thousand tons)	4,910	+53	−47	−73	+37	−66	−82	4,541
Carbon emissions (million tons)	689.8	+9.1	−1.9	−6.0	+8.2	−6.9	+0.9	664.2

FIGURE 9.

THE CONTRIBUTION OF PRICING INSTITUTIONS AND COLLECTIVE PARAMETER ASSUMPTIONS TO THE EFFECT OF MORE WIDESPREAD RESTRUCTURING ON SELECTED VARIABLES



nario and the partial restructuring baseline shows the effects of the change from regulated to market pricing in the still-regulated regions, holding the technological parameters at their baseline levels. Column 8 reports the results for each variable in the partial restructuring scenario.

Table 12 reports the effects of turning off specific assumptions under nationwide restructuring in terms of absolute differences from the values under the complete nationwide restructuring scenario. To determine how much of the total difference between nationwide restructuring and partial restructuring is due to a particular parameter or set of parameters, we can take the ratio of differences reported in columns 2 through 7 to the total difference between the numbers reported in columns 1 and 8.

Figure 9 provides several graphs that illustrat, for different variables, how much of the difference between the values under nationwide restructuring and partial restructuring is due to the collective parameter assumptions and how much is due to the change from regulated to market pricing. The length of the line represents 100% of the difference between the value of the relevant variable under nationwide restructuring and the value under partial restructuring. For NO_x emissions and coal-fired generation, the value under nationwide restructuring exceeds the value under partial restructuring; this is indicated by the plus sign (+) under nationwide restructuring (NR) in the graph. The large dot indicates the value of the relevant variable for the scenario reported in column 7 of Table 12, where the collective parameter assumptions are set at the baseline values and electricity is priced at marginal cost in all regions with time-of-day pricing for industrial customers. The percentage falling between the dot and the end labeled NR is the percentage of the total difference, or total effect of restructuring, due to the collective parameter assumptions. The percentage falling between the dot and the end labeled PR (partial restructuring) is the percentage due to the pricing regime.

The next few sections describe the decomposition results for different categories of variables.

Electricity Price

Based on the results reported in columns 1, 7, and 8 of Table 12 and as shown in Figure 9, 90% of the $1.50 per MWh difference in national average price between nationwide restructuring and the baseline is attributable to the collective parameter assumptions. The remaining 10% is attributable to the shift from regulated to market pricing.[24] The results reported in columns 2 through 6 of Table 12 indicate that the most important individual productivity assumptions are the rate of improvement in costs, the rate of improvement of heat rate at existing coal plants, and whether transmission capacity is allowed to expand.[25] Cutting the rate of improvement in the availability factor does not affect the price of electricity. Eliminating the RPS reduces the price only slightly.

The decomposition offers three surprising results. First is the relationship between national average electricity price and the presence or absence of growth in interregional transmission capacity. Basic economic intuition would suggest that relieving a constraint would tend to lower costs and thereby lower prices. Thus, one would expect that electricity prices would be higher in the scenario with nationwide restructuring and no transmission capacity growth between NERC regions. However, the opposite is true. A complete explanation would require an interface-by-interface analysis of trading between the regions and how changes in transmission capacity affects trading, which in turn affects generation and investment decisions in different regions differently. Such a detailed analysis is beyond the scope of this report. However, one important contributing factor to this outcome is that in regions where trade does not take place because of lower transmission capability, new gas facilities end up being built. Once they are built, these facilities are inexpensive to operate, and so they enter early in the dispatch order, which tends to push out the variable cost curve and have a depressing effect on price in the region.

The second surprising result is related to the effect on electricity price of a reduction in the rate of improvement in heat rates at existing coal plants. Intuition would suggest that less improvement in heat rate would raise costs and, therefore, raise prices. However, this is not what we observe, and the reason is instructive.

In market pricing regions, the electricity price is determined not by total costs but by the costs of the marginal unit. In the decomposition, several regions show a slight decrease in electricity price when there is less improvement in heat rates. The most significant drop is in MAAC, where electricity price falls by almost $5 per MWh. So, when there is less improvement in heat rate, the cost of supplying electricity from existing coal plants does not fall by as much and these plants are used less intensively. As a consequence, we find that an additional 3,830 MW-worth of new, combined-cycle, natural gas plants get built in MAAC. The new capacity has relatively low variable costs because it is very efficient. It shifts the variable cost ordering for generation to the right, which has a depressing effect on price. As one would expect, we observe an increase in capital costs in MAAC and a slight increase in total producer costs. Since revenues fall, producer profits also fall by about $1.4 billion. So the intuition that price would necessarily increase when heat rate improvements are less is not borne out. However, the fact that costs should rise for producers is confirmed.

The third surprising result is that restricting growth in the availability factor has no effect on national average electricity price. Simple intuition would suggest that reducing availability would lower total output from plants, raise the need for new investment, and lead to increases in price. However, when prices are set at marginal cost, the price-increasing effect of additional investment is not necessarily borne out. In this case, when improvement in availability factors is restricted, more investment in new gas, combined-cycle units follows. These units have lower operating costs and, therefore, enter early in the dispatch order, which can have a depressing effect on price—not an increasing effect, as would be expected if price were set at average cost.

Generation and Fuel Mix

The next section of Table 12 reports the results of the decomposition analysis for total generation and generation by fuel. Combining the results in columns 1, 7, and 8 of this table shows that 39% of the 23 billion kWh difference in generation between nationwide restructuring and partial restructuring is due to the collective parameter assumptions outlined in Table 3, and the remaining 61% is due to the pricing regime. Of the individual assumptions examined, rate of change in heat rate had the largest effect on total generation: 22 billion kWh. Eliminating transmission growth from the nationwide restructuring scenario results in 18 billion kWh of additional generation nationwide, consistent with the lower price found under that scenario.

The collective parameter assumptions appear to matter less than the pricing regime as determinants of the mix of fossil fuels used to generate electricity. Only 26% of the 213 billion kWh difference in total coal generation between partial restructuring and nationwide restructuring and 38% of the 260 billion kWh difference in total gas generation between the two scenarios is attributable to the collective parameter assumptions. Among the individual assumptions, the rate of change in costs seems to be the single most important contributor to the shift from gas to coal experienced as a result of more widespread restructuring.

The primary determinant of the change in renewables use as a result of more widespread restructuring is the RPS. Without the RPS, renewables generation would be reduced by 46 billion kWh, making it approximately equal to the level under the partial restructuring baseline. Thus, the RPS with the $17 cap on the RPS credit price appears to lead to a more than doubling of renewables generation nationwide. The total annual cost of this RPS policy in 2008 is $174 million, as represented by the increase in consumer expenditures on electricity.

Emissions

The third section of Table 12 reports the decomposition of the effects of assumptions about productivity growth, transmission growth, and the RPS on emissions of NO_x and carbon. Consistent with the findings regarding the mix of generation, the collective parameter assumptions are less important than the pricing regime in influencing changes in emissions from more widespread competition. As shown in Figure 9, only 22% of the difference between total NO_x emissions under nationwide restructuring and under partial restructuring is due to the collective parameter assumptions, with the remainder due to the change in pricing regime. The three most important assumptions are rate of improvement in cost, rate of improvement in plant availability, and the assumption about transmission growth. Eliminating the RPS or slowing the rate of improvement in heat rates leads to greater increases in NO_x emissions.

Interestingly, reversing the collective parameter assumptions about productivity and transmission growth and the RPS increases carbon emissions by an additional 0.9 MMT above the nearly 26 MMT increase associated with more widespread restructuring. This finding implies that more than 100% of the increase in carbon emissions associated with more widespread restructuring must be due to the change in pricing regime. Changing heat rate alone to its level under the partial restructuring baseline increases carbon emissions by an additional 8.2 MMT, and eliminating the RPS increases carbon emissions by 9.1 MMT. Counteracting these effects somewhat are the effects of the cost-improvement and availability-improvement assumptions. Slowing the rate of cost improvement to its baseline level results in a decline in carbon emissions that partially offsets the effect of heat rate improvements.

Time-of-Day Pricing Sensitivity

In addition to the decomposition analysis, we also performed a sensitivity analysis in which we looked at the effects of eliminating time-of-day pricing of electricity for industrial customers on prices and other variables. The results of this analysis are reported in Table 13. Unlike the analyses reported in Table 12, this is not a decomposition analysis. Both the nationwide restructuring case and the partial restructuring case assume that industrial customers face time-of-day prices in regions that have moved to competitive electricity pricing. However, in this sensitivity scenario, we combine all the assumptions of a nationwide restructuring scenario with the assumption of no time-of-day pricing for any customers in any region.

The elimination of time-of-day pricing for industrial customers has a big impact on electricity price. This sensitivity run shows that without time-of-day pricing, the national average retail price is not only higher than it was in the nationwide restructuring case, but also higher than it was in the partial restructuring case. Price is $2.50 per MWh, or 4%, higher than in the complete nationwide restructuring case, and $1 per MWh, or 1.6%, higher than in the partial restructuring case. Under time-of-day pricing, industrial customers face higher prices in peak periods and lower prices in off-peak periods than they do without time-of-day pricing. As a result, they reduce their demand in peak periods and increase it in off-peak periods. This load shifting behavior results in a decline in peak-period prices: a greater share of the load occurs during cheaper off-peak periods, thereby lowering average electricity prices for all consumers.

TABLE 13. TIME-OF-DAY PRICING SENSITIVITY ANALYSIS

	Partial restructuring (PR)	*Nationwide restructuring (NR)*	*NR w/o time-of-day pricing*
Price ($/MWh)	62.2	60.7	63.2
Total generation			
(billion kWh)	3,997	4,020	3,984
Coal	1,759	1,972	1,916
Gas	1,221	961	975
Nonhydro renewables	37	83	86
NO_x emissions (thousand tons)	4,541	4,910	4,819
Carbon emissions (MMT)	664.2	689.8	677.3

Consistent with the findings for price, eliminating time-of-day pricing for industrial customers results in less total generation than under either the nationwide restructuring case or the partial restructuring case. Coal use declines with the elimination of time-of-day pricing, and both gas and renewables use increase. This result is due in part to the fact that load curves are "peakier" and thus more gas turbines are needed when there is no time-of-day pricing.

Consistent with those changes in the generation mix, eliminating time-of-day pricing leads to a reduction in NO_x and carbon emissions, but emissions are still higher than under partial restructuring. Eliminating time-of-day pricing leads to 91,000 tons less NO_x emissions than under the standard nationwide restructuring scenario. Partly as a result of the greater shift from coal to gas, carbon emissions are 12.5 MMT lower without time-of-day pricing.

■ ■ ■

CHAPTER SIX

Ancillary Benefits of an Electricity Sector Carbon Policy

Although electricity restructuring could lead to increases in NO_x emissions, policies to address greenhouse gas (GHG) emissions from electricity generators could help reduce emissions of NO_x as well.

The future course of domestic policies to reduce greenhouse gases is highly uncertain. The preponderance of emerging scientific evidence suggests that emissions of greenhouse gases are leading to warming of the planet (IPCC 2001). Although President George W. Bush has announced that the United States will not participate in an international agreement to reduce greenhouse gases that conforms to the guidelines of the 1997 Kyoto Protocol, his statement does not indicate that there will be no domestic global warming policy. The Bush administration's National Energy Policy, released in May 2001, suggests that voluntary programs are helping slow the growth in GHG emissions and that more research is needed into the climate change issue. (NEPDG 2001). In February 2002, EPA announced a proposal to initiate a voluntary program to reduce carbon emissions with a goal of reducing the carbon intensity of the U.S. economy. The president has also expressed support in the past for the consideration of incentive-based policies to address these issues. Several bills introduced into the 106th and 107th Congress would cap carbon emissions from electricity generators as a part of a comprehensive cap-and-trade program on multiple pollutants. One such bill, sponsored by Senator Jeffords of Vermont, was passed out of the Senate Environment and Public Works Committee in June 2002.

Eventually, the United States is likely to implement a policy to reduce carbon emissions, and there is some chance that it will be an incentive-based policy, like a cap-and-trade program or, perhaps less likely, a tax on carbon emissions. Auctioned emissions permits have been shown to be a cost-effective approach to reducing carbon emissions from the electricity sector (Burtraw et al. 2001b). From a modeling perspective, an auction of emissions allowances is identical to a carbon tax with the tax level per ton of emissions set to the expected permit price. Hence, for convenience we model a carbon tax policy.

Eventually, the United States is likely to implement a policy to reduce carbon emissions, and there is some chance that it will be an incentive-based policy, like a cap-and-trade program.

Several actions that firms or others might take in response to such a policy to slow atmospheric GHG accumulation from fossil-fuel use would also tend to reduce various "criteria" air pollutants (as defined in the Clean Air Act). The benefits that result would be ancillary to GHG abatement. Moreover, these benefits would tend to accrue in the near term, as does the cost of abatement, but any benefits from reduced climate change would mostly accrue over several decades or longer. In addition, ancillary benefits accrue largely to those countries undertaking mitigation action; the benefits of reduced climate change risks, in contrast, accrue at a global level. In this section of the report, we look at how some low- and moderate-level carbon taxes are likely to affect total generation, fuel mix, electricity price, and emissions of carbon and NO_x from the electricity sector.[26]

Scenarios

This analysis considers two carbon policies. The first is a $25 tax per metric ton of carbon emissions from the electricity sector only, and the second is a $75 tax per metric ton. The $25 tax level has been advocated by Americans for Equitable Climate Solutions, as a part of their proposal for a modest fee on carbon emissions that escalates over time to provide an incentive to reduce emissions and develop new lower-emitting technologies.[27] In both scenarios, we assume that the tax is announced in 2002 and goes into effect in 2008.

The policies that we focus on are directed solely at the electricity sector, and we look only at the emissions effects in the electricity sector itself. If a policy directed exclusively at electricity generators were implemented, it would affect the price of electricity and could result in some substitution away from electricity toward natural gas or other fuels. Fuel switching by end users would have implications for carbon and NO_x emissions outside the electricity sector that are not reflected here.

An analysis of benefits requires a clear definition of a baseline against which the prospective scenario can be measured. In a static analysis, the baseline can be treated as the status quo, but since climate policy inherently is a long-term effort, questions arise about projecting energy use, energy regulation, technology investments, and GHG emissions and criteria pollutants, with and without the GHG policy (Morgenstern 2000).

The issue of the baseline is confounded by ongoing changes in the standards for criteria air pollutants. If one proceeds on the basis of historical standards and ignores expected changes in the standards, the ancillary benefit estimate will overstate environmental savings. Indeed, historical emissions rates may be 10 times the rates that apply for new facilities. In addition, the recent tightening of standards for ozone and particulates, and associated improvements in environmental performance over time imply that benefits from reductions in criteria air pollutants resulting from climate policies will be smaller in the future than in the present.

The baseline for the analysis includes nationwide restructuring of the electricity industry—that is, all regions of the country are expected to have implemented market pricing of electricity by the year 2008. We include the SIP seasonal NO_x policy. In this framework, changes in aggregate summer-season NO_x emissions, in response to carbon policies, are not expected to be significant in the region of the country covered by the NO_x cap, except for the effects of changes in the location of emissions, which are captured in the model.

In this analysis, we assume that generators can reduce carbon emissions only by switching to less carbon-intensive fuels, dispatching gas facilities before coal-fired facilities, or reducing production. We do not include in the model any explicit carbon-reduction technologies, such as postcombustion carbon capture, primarily because such technologies would not be economic to adopt under the carbon tax levels considered here. We also do not allow for carbon sequestration (by planting trees) or international trading of carbon emissions allowances, which would allow a domestic electricity generator to pay others to reduce their emissions of carbon.

Results

The results of this analysis are reported in three tables. Table 14 shows the effect of the carbon tax on total generation, generation by coal and gas, and retail electricity price. Table 15 reports the effects of the carbon tax on carbon emissions, and Table 16 reports the effects of the carbon tax on NO_x emissions. In each table, results are reported separately for MAAC, the SIP Call region, and the nation as a whole. The results in the row labeled "No carbon tax" are for the baseline described above. Changes from the baseline associated with the imposition of a carbon tax are reported in subsequent rows.

Generation and Price

Table 14 shows that the effect of a small carbon tax on the bundled retail electricity price is slightly more pronounced in the SIP region than in the rest of the country. A $25 carbon tax leads to a $0.22 per MWh, or 3%, increase in average electricity price in MAAC; a $0.33, or 5.3%, increase in the SIP regional price; and a $0.3, or 5%, increase in the national average price. Total generation in the MAAC region falls by 2 million MWh, just under 1%, but in the larger SIP region the decline is just over 2%. Nationwide generation falls by 55 million MWh, or just over 1%.

The $75 carbon tax results in a 17% to 20% increase in electricity price in the SIP Call region and nationwide, and a decline in total generation. There is a more dramatic shift from coal to gas in MAAC and throughout the country with the $75 tax than there is with the lower tax. Nationwide, coal generation falls by nearly 420 million MWh, or 21%, under a $75 tax. Gas generation increases by 147 million MWh, or close to 15%.

Carbon Emissions

Nationwide, the $25-per-metric-ton carbon tax results in a 26 MMT, or 3.8%, drop in carbon emissions as shown in Table 15. Consistent with the relatively small 1% decline in total generation in the MAAC region, carbon emissions fall less sharply in the smaller region where the decline is 1 MMT, roughly 3%. The $75 tax results in a nearly 16% drop in carbon emissions from electricity generators across the nation.

NO_x Emissions

The $25 carbon tax leads to a 4% to 6% decline in NO_x emissions across all three regions, as shown in Table 16. Two-thirds of the national reduction in NO_x emissions occurs within the SIP Call region. NO_x emissions appear equally or more responsive in percentage terms than carbon emissions to a tax at this level.

TABLE 14.

GENERATION BY FUEL AND ELECTRICITY PRICE IN NATIONWIDE RESTRUCTURING SCENARIO WITH SIP REGIONAL NO_x POLICY AND CHANGE DUE TO CARBON TAXES FOR 2008

Policy scenario	*Generation (million MWh)*			*Price ($1997/MWh)*
	COAL	GAS	TOTAL	
MAAC				
No carbon tax	85	97	280	73.9
$25 carbon tax	- 7	+ 5	- 2	+ 2.2
$75 carbon tax	- 16	+ 10	- 7	+ 12.7
SIP Call region				
No carbon tax	1,225	348	2,162	62.5
$25 carbon tax	- 61	+ 12	- 50	+ 3.3
$75 carbon tax	- 244	+ 119	- 118	+ 12.7
Nationwide				
No carbon tax	1,972	961	4,020	60.7
$25 carbon tax	- 100	+ 26	- 55	+ 3.0
$75 carbon tax	- 417	+147	- 187	+ 11.6

TABLE 15.

ANNUAL CARBON EMISSIONS BY REGION IN NATIONWIDE RESTRUCTURING SCENARIO WITH SIP REGIONAL NO_x POLICY AND CHANGE DUE TO CARBON TAXES FOR 2008 (MILLION METRIC TONS)

Policy scenario	*MAAC*	*SIP Call region*	*Nationwide*
No carbon tax	35	393	690
$25 carbon tax	–1	–17	–26
$75 carbon tax	–4	–59	–108

TABLE 16.

ANNUAL NO_x EMISSIONS IN NATIONWIDE RESTRUCTURING SCENARIO WITH SIP REGIONAL NO_x POLICY AND CHANGE DUE TO CARBON TAXES FOR 2008 (THOUSAND TONS)

Policy scenario	*MAAC*	*SIP Call region*	*Nationwide*
No carbon tax	225	2,672	4,910
$25 carbon tax	–14	–128	–191
$75 carbon tax	–37	–506	–937

The $75 carbon tax has a more pronounced effect on NO_x emissions. The $75 carbon tax translates into an approximately $0.02-per-kWh increase in the cost of coal-fired generation. NO_x emissions in the SIP Call region fall by 506,000 tons, nearly 19% of baseline levels, and in the MAAC region, they fall by 37,000 tons, roughly a 16% drop.[28] Once again, NO_x emissions appear to be even more responsive in percentage terms than carbon emissions to the imposition of the carbon tax. Nationwide, NO_x emissions fall by 937,000 tons, or roughly 19%. This decline is greater than the 16% decline in carbon emissions from the sector, and it represents approximately 65% of the drop in NO_x emissions that would result from a shift from seasonal to annual NO_x controls. The larger percentage drop in NO_x emissions than in carbon emissions reflects the fact that the carbon policies cause a substantial switch from existing coal to new gas facilities, and the difference in NO_x intensity between the two technology-fuel combinations is much larger than the difference in carbon intensity. In addition, NO_x emissions fall because a carbon tax leads to an overall reduction in electricity usage and, therefore, generation.

■ ■ ■

CHAPTER SEVEN

Conclusion

This report presents a simulation-modeling analysis of the potential effects on fuel mix, emissions of CO_2 and NO_x, and customers' electricity rates under a complete restructuring of this nation's electric utility industry. Nationwide restructuring is modeled in conjunction with alternative policy regimes for reducing NO_x and CO_2 emissions. The results suggest that nationwide restructuring is likely to increase NO_x and CO_2 emissions nationwide and in the eastern portion of the country (the SIP Call region). This will be accompanied by a pronounced shift from gas-fired to coal-fired generation and a small decline (on average) in customer rates, assuming industrial customers shift a portion of their usage to lower-cost, off-peak hours. The results further show that the increase in NO_x emissions in the eastern United States would be substantially mitigated by implementing the NO_x emissions caps called for in the NO_x SIP Call, with relatively minor effects on consumer prices.

One important finding is that time-of-day pricing is a critical assumption in the analysis. Although nationwide restructuring with time-of-day pricing for industrial users leads to a modest decrease in the average end-use price of electricity, removing time-of-day pricing leads to modestly higher rather than lower customer rates. This drop in consumption is not sufficient to undo the increase in NO_x and carbon emissions brought about by the shift to nationwide restructuring.

This study also shows that certain policies will reduce NO_x and CO_2 emissions by far more than nationwide restructuring will increase those emissions. Moreover, a more comprehensive year-round regulatory policy governing NO_x in the broadly defined SIP Call region would lead to a modest increase in electricity rates. CO_2 emissions can be reduced through a carbon tax, but achieving a very substantial reduction (i.e., roughly 15%) would increase electricity rates by 19% nationwide. The $75-per-ton carbon tax would lead to a sharp drop in coal-fired generation and a somewhat smaller decline in total generation as customers respond to the higher prices.

A renewables portfolio standard can contribute to reductions in NO_x and CO_2 emissions at the cost of a very small increase in electricity rates (less than 0.1%). The RPS program modeled in this study would increase the share of nonhydro renewables from about 2% to 3% of U.S. generation.

Notes

1 In September 2001, the California Public Utilities Commission voted to end retail competition in electricity markets in California. This change is not reflected in the model results; however, given the general lack of coal-fired generating capacity in California, not incorporating this change should not have serious implications for the relevance of the results reported here.

2 The study addresses only NO_x and CO_2; sulfur dioxide (SO_2) emissions are capped at the national level based on Title IV of the Clean Air Act.

3 FERC implemented this requirement by issuing Order 888 in 1996 (U.S. FERC 1996a). Over time, FERC recognized that Order 888 was only a limited success, in part because utilities that owned both generation and transmission facilities had little incentive to open up their transmission grids for use by their competitors in generation markets. In 1999, FERC issued Order 2000 to break the link between generation and transmission activities. Order 2000 provides specific guidelines and incentives for the establishment of independent regional transmission organizations (RTOs) to manage use of the transmission grid.

4 Ando and Palmer (1998), White (1996), and Hunt and Sepetys (1997) analyze the factors that influence state decisions about the direction and pace of restructuring. The status of state deregulatory activities is tracked by the Energy Information Administration (U.S. EIA 2000).

5 For a discussion of the many ways electricity restructuring could affect the environment, see Palmer (1997, 2001) and Burtraw et al. (2001c).

6 Palmer et al. (1998) and Burtraw et al. (2000) include an annual cap on NO_x emissions in the SIP region. U.S. DOE (1999) includes the five-month summer cap applied to the original 22-state NO_x SIP Call region.

7 For more information on the recent history of the regulation of NO_x emissions from the electric power sector, see Burtraw et al. (2000).

8 U.S. EPA 1998a.

9 U.S. EPA 1998b, Table 2–1. The percentage reductions pertain to EPA's original program that targeted 22 states and the District of Columbia. The EPA baseline includes only Phase I controls in the OTR.

10 The location of NO_x emissions, however, could be affected by restructuring, and those shifts in location could cause environmental damages.

11 Environmental Defense (2000).

12 In our earlier work (Burtraw et al. 2000), we were interested in the near-term effects of restructuring on emissions and focused on the year 2003. For that analysis, we used version 1 of the Haiku model, which allowed for parametric representation of investment and retirement of generating plants and, therefore, was not appropriate to analyzing the effects of restructuring on those activ-

ities and their consequences for emissions. Using the new version of Haiku, which has endogenous investment and retirement and which is described in more detail below, we are able to analyze how investment and retirement decisions are affected by more widespread competition and the implications of those changes for emissions.

13 Most regions that have implemented restructuring allow consumers to take "standard offer service" under capped rates that are generally somewhat lower than historic rates under regulated pricing. In most cases, this capped rate option does not continue past 2008. We do not incorporate the possibility for standard offer service in our scenarios.

14 The elasticity of demand for commercial customers is -.228. For residential customers, the elasticity varies from -.07 to -.43, depending on season of the year and region of the country. In general, residential demand elasticities tend to be higher in the winter and lower in the summer.

15 Reserve services are differentiated to the extent that steam generators are limited to providing only 50% of total reserves.

16 The price of reserve services in MAAC ranges from roughly $44 per kW per year to $48 per kW per year. In regions with excess capacity, such as ECAR, the price is typically under $40 per kW per year. In New York State and in the Northwest, however, reserve prices tend to be much higher, ranging from just under $60 per kW per year to just over $200 per kW per year in the Northwest under some scenarios.

17 For the purpose of interregional power trading, we calculate a willingness-to-pay in regulated 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 marginal reserve "prices" comparable to market-pricing regions, reflecting the marginal scarcity value of reserve services for a given level of generation capacity and electricity demand.

18 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 market pricing regions times an optimistic rate of change, plus the proportion of megawatt-hours sold in regulated regions times the historical rate of change (under regulated pricing) in each parameter. The weights are constructed using electricity sales data from 2000, prior to the implementation of restructuring in most states.

19 Our model assumes that there are no transmission constraints within regions, and, therefore, we do not model expansion of the intraregional transmission system.

20 For a discussion of different RPS proposals, see Clemmer et al. 1998.

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

22 These regions include NE, NY, MAAC, STV, ECAR, and MAIN; they exclude a small portion of western Missouri (that is part of MAIN) and small parts of Illinois and Wisconsin. These regions also 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 OTR. The reconciliation of these two programs may ultimately involve their participation.

23 This emissions cap was determined by applying the emissions rate of 0.15 lb per MMBtu to fossil-fired generation in the baseline for 1997, which is the same methodology applied by EPA. Forecast electricity generation varies slightly in our model, and the geographic coverage varies slightly, from the EPA model (U.S. EPA 1998a, 1998b, 1999).

24 The 90% is calculated by dividing the number in the seventh column by the total change in price due to nationwide restructuring.

25 Note that it is not appropriate to add together the individual changes, due to single parameter assumptions displayed in columns 2 through 6 of Table 11, and compare them with the aggregate change associated with relaxing all parameter assumptions reported in column 7 of Table 11. The numbers reported in this table represent national averages, or aggregates, across all the regions and time blocks in the model. In the aggregate case there are a multitude of potential interactions between different assumptions that could be operating in individual regions or time blocks, and these interactions could be going in different directions in different regions. Thus, it is unclear how the sum of effects of turning off specific assumptions at the national level should compare with the effect of turning off a group of assumptions together.

26 Earlier studies of ancillary benefits of carbon policy in the U.S. electricity sector include Burtraw et al. forthcoming.

27 For more information about Americans for Equitable Climate Solutions, formerly known as Skytrust, see http://www.aecs-inc.org (accessed May 5, 2002).

28 A small part of the NO*x* emissions reduction occurs during the summer months because controls that are put in place to comply with the NO*x* cap (which goes into affect in 2004) are assumed to continue to operate after the carbon tax takes effect.

29 The RFF Haiku model is continually undergoing modifications and revisions. For a copy of the latest model documentation, see Paul and Burtraw (2002).

30 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.

31 The current version of the Haiku model includes the 13 NERC regions and subregions: NE, NY, MAAC, ECAR, STV, FPCC, MAIN, MAPP, SPP, ERCOT, CNV, NWP, and RA, as they were defined in 1997. Recently, Entergy Corporation has moved from the SPP region to the SERC region, but for purposes of our analysis it is still included in SPP.

32 Market prices for generation are based primarily on variable costs. However, retail electricity prices are calculated as the sum of generation and reserve costs, and transmission and distribution costs plus an adder that accounts for costs not explicit in our model. The miscellaneous adder costs result from low-income assistance and conservation programs, other customer benefit programs, out-of-merit-order dispatch, regulatory failures, etc. The adder is calculated such that Haiku yields average annual

retail prices in 1997 equal to the observed average annual retail prices in 1997 in each region of the country. The adder declines over time by 2.5% per year. By not varying the adder across scenarios, we are implicitly assuming that regulatory programs, such as low-income assistance or conservation programs, will be continued after restructuring at roughly their current levels. Given that most states are incorporating some mechanism to maintain current levels of funding for these types of social programs into their restructuring laws and/or regulations and that most federal restructuring bills include similar provisions, we believe that this is a reasonable assumption.

33 Though each model plant represents a set of generators that have nonidentical parameters, the assumption is that when a percentage of a model plant retires, the retired generators are exactly average. In other words, all the averaged parameters remain unchanged.

34 The majority of postcombustion NO_x controls are added in regions at a time that they remain under regulated pricing. We maintain the assumption that the NO_x control capital costs are eligible for stranded cost recovery, which is an assumption that carries over from the previous study.

35 Currently we are using information from EIA's Annual Energy Outlook for 2000 to derive our fuel supply curves.

36 These are essentially three data points from EIA's own natural gas supply curve.

37 Very little information is lost when the list of coal types is shrunk because those that we skip are either very small or coal types that are not used for electricity generation.

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APPENDIX

The RFF Haiku Model

The RFF Haiku Model is a simulation model of regional electricity markets and interregional electricity trade with an integrated algorithm for NO_x and SO_2 emissions control technology choice.[30] The model can be used to simulate changes in electricity markets stemming from public policy associated with increased competition or environmental regulation. The model simulates electricity demand, electricity prices, the composition of electricity supply, interregional electricity-trading activity, and emissions of major pollutants, such as NO_x and CO_2, from electricity generation in different regions. The model has been used to identify the least-cost mix of NO_x emissions control technologies for power plants that achieve specified target levels of emissions under various environmental policies (technology-based policies, emissions taxes, or regional emissions trading). It also can look at the effect of using different mechanisms to distribute emissions allowances on the efficiency of pollution-allowance trading programs. In both this study and Burtraw (2000), the model has been used to analyze the effects of electricity restructuring on air emissions.

Two components of the Haiku model are the intraregional electricity-market component and the interregional power-trading component. These components are described in more detail below, followed by a discussion of how version 2 of the Haiku model, used for this study, differs from version 1, which was used for the earlier study.

Intraregional Electricity Market Component

The intraregional electricity market component uses a reduced-form dispatch algorithm to develop electricity supply curves for each of 13 NERC regions or subregions during three seasons (summer, winter, and spring-fall).[31] The supply curves are constructed using information on capacity (net of planned and unplanned outages), variable operating and maintenance costs (including pollution-control costs), and fuel costs for several "model plants," each of which represents a group of generating units aggregated by region, fuel type, technology, and vintage classifications. The operation of model plants in each time period is determined according to a market equilibrium, identified by the intersection of the demand and supply that includes the opportunities for interregional power trading. The market price of electricity is determined according to the regulatory framework specified in the scenario. Market prices (based on marginal costs) and regulated prices (based on average embedded costs) both can be represented. Under market pricing, the equilibrium price is equal to the sum of the market-clearing price of electricity generation and reserve services, plus the additional costs of transmission and distribution services, including intraregional transmission losses.[32] Under regulated pricing, the equilibrium price is set according to the average cost of generation and reserve services (including embedded capital costs) across all customer classes within a particular season, plus transmission and distribution costs.

The demand, supply, and emissions components of this model and the underlying data are described in more detail in the next sections.

Demand

Using data from the U.S. Energy Information Administration (EIA), the demand component classifies annual electricity demand by three customer types (residential, commercial, and industrial), by three seasons (summer, winter, and fall-spring), and by four time blocks (superpeak, peak, shoulder, and baseload hours). Demand is represented by a price-sensitive demand function where each combination of customer class, season, and time block has its own demand function with a unique set of parameters.

Supply

The model plants that populate the supply component of the model are constructed using information at the generating-unit level on generating capacity and engineering characteristics drawn from three EIA databases: EIA 860, EIA 759, and EIA 767. This information is aggregated from the "constituent plant" to the model-plant level, based on the fuel type (including the coal-demand region where a plant is located), technology (including whether the plant had a scrubber installed in 1997 or not), and vintage of each unit. The model-plant definitions used in Haiku are adapted from those developed by EPA for the Clean Air Power Initiative project (U.S. EPA 1998a). As a part of that project, EPA's contractor, ICF, Inc., developed prototypical operating cost information for each model-plant category. This information is combined with regional fuel cost, the costs associated with endogenously selected NO_x control technologies (and, in the case of emissions-allowance trading, the cost of NO_x allowances), and unit availability (reflecting planned and unplanned outages) to develop regional supply curves. The geographic location of each model plant is determined by generation-weighting the latitude and longitude information for each constituent plant. Each region has up to 45 model plants.

Emissions

The model contains emissions factors for NO_x, SO_2, and CO_2 for each model plant based on information from EPA and EIA on plant performance and total emissions. The electric power industry's SO_2 emissions are capped under Title IV of the 1990 Clean Air Act Amendments and, therefore, would not be affected by restructuring, but the capability of representing alternative emissions policies is available. Information on the costs of NO_x emissions control, which is the focus of the current project, is obtained for all generating facilities and aggregated to the model plant level. NO_x control strategies are chosen endogenously based on cost minimization, and the costs of these controls feed into the calculation of NERC region-wide electricity supply functions. This interaction between endogenously chosen emissions-control technologies and emissions factors with electricity supply allows the model user to analyze the effect of alternative environmental policies on interregional power trading and other market outcomes, as well as their effect on emissions.

The effects of alternative environmental policies are indicated by changes in electricity prices, quantity of electricity produced, amount of electricity generated using each model-plant technology, and levels of emissions by model plant and by region. The geographic location of emissions can be specified at two levels of detail. At an aggregate level, they are located at the calculated site of the model plant; at a disaggregated level, they are assigned to the generating units that constitute each model plant, based on the 1997 generation of these units. New construction is represented as a variety of new model plants. The constituent units for new model plants are assumed to be located on a weighted basis at the same location as existing constituent units using similar fuels.

Interregional Power Trading Component

This model component solves for the level of interregional power trading necessary to equilibrate differences in regional equilibrium electricity prices (gross of transmission costs and power losses) across NERC regions. These transactions are constrained by the assumed level of available interregional transmission capability as reported by NERC, and they reflect interregional transmission losses and transmission fees.

Transactions are determined by the excess energy-supply function for exporting regions and the excess energy-demand functions for importing regions. The marginal cost of generation for export in supplying regions is determined after solving (or re-solving) for equilibrium prices within the region. The model user is free to vary the parameters—such as the amount of transmission capability between NERC regions or the cost of transmission service—to determine the impact on power trading, electricity prices, and ultimately on emissions.

New Features of Version 2 of the Haiku Model

This analysis uses version 2 of the Haiku model, an expanded and updated version of the model used in the earlier study funded by the Power Plant Research Program. The next several sections discuss some of the enhancements to the Haiku model.

Operation and Scheduling of Generation Capability

The operation of units depends on their availability and on variable costs. Availability is calculated based on scheduled and unscheduled outages. The model allocates scheduled outages across seasons and time blocks in a way that maximizes the value of generation assets. How often plants will be down because of unscheduled outages is unknown. We use information on the average value of unscheduled outages in recent years by type of generating facility to represent the expected value of unscheduled outages in figure years. The expected unscheduled outage is subtracted from potential generating capacity to identify available capacity.

Units that are available in a given season (and time block for hydro and wind resources) are ordered according to variable cost, and the operation of units is determined by proceeding up the variable cost schedule until demand is satisfied. Variable costs for model plants are constructed as a distribution based on data for constituent units, so the variable cost schedule is also a continuous schedule over most of its domain. Version 2 of the model includes updated data for operating and maintenance costs for all steam plants.

Reserve Services

Available generating capacity that is not used for generation is reordered according to going-forward costs, which include fixed O&M for all plants and capital costs for new plants. The ordering according to going-forward cost is used to identify a least-cost schedule for meeting reserve requirements, which are identified based on EIA and NERC estimates. In regulated regions, the model selects the capacity from the going-forward cost ordering and adds this capacity to the capacity necessary to meet generation needs. Electricity price is set to collect revenue sufficient to recover total costs, which include the capital costs for all reserve units.

In competitive regions, the units providing reserve services must be given incentives to provide those services. Furthermore, the payment mechanism must be incentive-compatible so that units selected to generate would not be better off withholding supply in the generation stage and offering that supply for reserve status. Consequently, a reserve payment is made to reserve capacity that is sufficient to meet fixed costs, such that the requisite capacity remains in service or enters the market. In addition, that same payment is also made to all units that generate to ensure they do not withhold from the generation market.

Endogenous Investment and Retirement

The model allows for electricity generators to make decisions about investment in new facilities or retirement of existing facilities, based on expectations about going-forward profits over a 20-year forecast horizon. Going-forward profits are calculated as the difference between expected future revenues and going-forward costs, which include future fuel costs, variable and fixed O&M costs for all plants, and the capital costs of new plants. Haiku simulates multiple years simultaneously and, through iteration, each year informs the others. The model determines the optimal level of capacity for each type of model plant in each region by maximizing the net present value of the going-forward profit stream at each model plant and in total through adjustments to the amount of operational capacity at each model plant in each year, within specified capacity bounds. New capacity is added when it is profitable to do so. Existing plants are retired when their revenues are unable to cover going-forward costs. Because the model plants are composed of many separate generating units, we allow a model plant to retire incrementally, as this represents the case when some constituent generators are retired while others are not.[33]

The characterization of technology performance characteristics and costs also has been significantly improved. New technologies have been added to the set of potential investments, including model plants with advanced natural gas combined-cycle generators and advanced natural gas combustion turbines. The parameters for these emerging technologies are taken from an EIA analysis, which itself is based on "learning by doing" and calculates declining cost for incremental investments as installed capacity grows. In Haiku, the performance parameters and the capital costs for these new technologies is fixed at a level that reflects the learning-by-doing outcomes found in EIA's reference case scenario. However, operating cost and performance parameters vary over time, depending on scenario, as described in Table 3.

Stranded Costs

Stranded costs in Haiku are calculated based on data on the capital portion of electricity price in 1997 from EIA (U.S. EIA 1997). After calculating the portion of electricity price that was a payment to capital, we multiply that share by the total revenue in 1997 to estimate the total actual payment to capital, by NERC subregion.

We assume a straight-line, 30-year depreciation schedule to be in place in 1997, assume a uniform distribution with respect to the vintage of existing capital, and then estimate the total value of undepreciated capital in 1997. Each year after 1997 that a region remains under regulated prices, we assume a portion of undepreciated capital costs are recovered in prices. For instance, in 1998 the model makes the first payment on the most recently added unit of capital, the second payment on the capital built in the previous year, and so on, including the last payment on the capital built 30 years ago, thus fully depreciating that unit of capital and removing it from the accounting books. To the capital cost of generation assets in place in 1997, we add NO_x control capital costs, but we do not add new generation capital.[34] The estimate of potentially stranded costs in any year is the resulting sum of undepreciated generation capital with a pre-1997 vintage, plus the undepreciated NO_x control capital costs.

The amount of actual stranded cost calculated in the model depends on the stream of revenues net of variable costs that can be used to pay off capital costs. The estimate of stranded costs is made for the year in which a region begins competitive pricing by estimating the present discounted value of all revenue and cost streams. Stranded cost equals the difference between potentially stranded costs plus variable costs minus revenues.

We assume the regulator estimates stranded benefits as well as stranded costs. Stranded benefits are profits that are earned by electricity-generating assets existing in 1997, in excess of normal rates of return, and that are due to the transition from regulation to competition. We assume the regulator offsets stranded costs at individual facilities in a firm with stranded benefits at other facilities in the same firm. Stranded costs and benefits are considered offsetting within a firm but not across firms. More precisely, the estimate of stranded costs is the sum of revenue and cost streams across all existing model plants aggregated to the level of firms existing in 1997. At the regional level, stranded costs are the sum of stranded costs across all firms with positive stranded costs.

We assume that the regulator will allow utilities to recover 90% of stranded costs through an annuity and that the stranded cost recovery period extends for 10 years from the date when restructuring is enacted. We calculate the effect of stranded cost recovery on price by dividing the annual revenue requirement to recover stranded cost by total delivered electricity, which amounts to a per unit surcharge to recover stranded costs.

Transmission and Distribution

In the new version of the model, intraregional transmission losses change by year, based on data from EIA. The costs of existing transmission and distribution services have been updated and are held constant. This approach is a compromise that balances two considerations. On the one hand, existing transmission and distribution capital is being depreciated, which suggests costs should decrease. On the other hand, capacity is also being replaced and modernized, which imposes new cost. Additions to transmission capability are implemented without additional cost, under the assumption that most improvements and expansion in capability are likely to come along existing easements and corridors, probably through software advances, such as flexible alternating current transmission systems or FACTS technology, rather than through major new capital investments in new transmission lines.

Fuel Supply Curves for Natural Gas and Coal

Version 2 of the Haiku model includes fuel-market modules for coal and natural gas. Both fuel-market modules are derived entirely from EIA data.[35] All other fuel prices are specified exogenously, with most changing over time.

For natural gas, EIA reports projections of consumption and wellhead price for the entire U.S. economy for three cases: low economic growth, reference case, and high economic growth. Haiku uses these three data points to derive a linear, natural gas supply curve for the entire U.S. economy.[36] EIA also reports projected natural gas consumption by all sectors of the economy except electric utilities. Using these data, Haiku calculates the wellhead price for natural gas, based on endogenous natural gas consumption by the electric utility sector and exogenous consumption by all other sectors. Also from EIA data, a natural gas markup (transportation fee) is calculated for each region of the country, allowing Haiku to express delivered natural gas price as a function of electric utility demand for natural gas.

EIA reports projections of coal consumption by electric utilities, and mine-mouth coal price for different coal types, by coal supply region. Haiku takes those data and aggregates them to a more manageable list of 14 coal supply categories.[37] For each there is an estimated heat content, sulfur content, and mercury content. EIA reports that a 10% deviation from its projected coal production will result in a 1% change in its projected coal price. There is also a markup (transportation fee) for each combination of coal demand region and coal supply region that Haiku takes from EIA data. With this information, Haiku calculates a coal supply curve that describes the delivered price of each of 14 coal types, in each region of the country, as a function of electric utility demand for each type. In a given NERC subregion modeled in Haiku, up to five types of coal are used.

Fuel Supply and Cost Data for Renewables

Biomass fuel-supply availability and delivery are modeled at the regional level for the types of biomass fuels available in each region. Wind resources characterized by class and region of the country are also incorporated in the model. The performance and cost data for these technologies have been updated.

Improved Characterization of Nuclear Performance and Cost

We performed a detailed analysis of the performance of nuclear units and reviewed available data on new investments in these units as of 1997. This information was used to categorize all existing generating units as efficient or inefficient model plants, and continuous cost curves and availability estimates for each model plant were estimated.

Upgrade Emissions Compliance Algorithm and Data

The new algorithm for compliance with emissions standards or emissions caps solves for the least-cost set of postcombustion investments. The algorithm solves in sequential fashion over years of the modeling horizon. The model first solves for the controls necessary to meet emissions-reduction requirements for the first simulation year (say, 2001), then those controls are assumed to be in place while the model calculates the additional controls that need to be installed in subsequent simulation years. The variable costs of emissions controls, plus the opportunity cost of emissions allowances under cap-and-trade programs, are added to the variable cost of generation in establishing the operation of generation capacity. If the requisite controls raise costs enough that revenues do not cover capital costs, including the cost of pollution control, or if variable costs rise enough that the utilization rate of a model plant falls sufficiently, the model plant will retire an incremental portion of capacity.

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Glossary

Common terms and abbreviations used in this report

cap-and-trade An incentive-based policy under which an industry's emissions are capped at levels below previous levels, and generators who pollute less than their allocated share of the cap can sell permits to those who pollute more;

CO_2 Carbon dioxide

EPA Environmental Protection Agency

FERC Federal Energy Regulatory Commission

G&A General and administrative costs

NERC North American Electric Reliability Council

NO_x Nitrogen oxides

O&M Operation and maintenance costs

OTR Ozone transport region: a region comprising 11 Northeastern and Mid-Atlantic states and the District of Columbia that was designated in the Clean Air Act Amendments of 1990 as having a regionwide ground-level ozone problem worthy of a regionally developed and implemented strategy to combat it.

RPS Renewables portfolio standard: a requirement that a certain percentage of the electricity sold be generated using a renewables-based technology

SIP Call region the region, including 19 Eastern states, plus the District of Columbia, that is subject to the EPA requirement to submit plans for achieving substantial NO_x emission reductions beginning in May of 2004 in order to comply with new stricter ozone standards

SIP State implementation plan (for compliance with the Clean Air Act)

SO_2 Sulfur dioxide

time-of-day pricing the practice of allowing electricity prices to vary over the course of the day to reflect the costs of supplying electricity at a particular point in time. Time-of-day pricing typically leads to higher prices in peak periods and lower prices in off-peak periods . In this analysis, time-of-day prices are determined at the time of consumption and not in advance.

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