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The Environmental Impacts of Electricity Restructuring

Looking Back and Looking Forward

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RESOURCES FOR THE FUTURE

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Abstract

In the mid-1990s, when the Federal Energy Regulatory Commission was preparing to release Order 888 requiring open access to the transmission grid, the commission, environmental groups, and the Environmental Protection Agency, among others, raised the question of how open access and greater competition in wholesale electricity markets might affect the environment. If open access worked as expected, underutilized older coal-fired generators in the Midwest and elsewhere might find new markets for their power, leading to associated increases in air pollution emissions. Restructuring also might lead to retirements of inefficient nuclear facilities, whose generation would be replaced by fossil generation, further increasing emissions. On the other hand, some suggested that in the long run, the anticipated increase in investment in new gas-fired generators might accelerate a switch from coal to gas that would decrease emissions. Lastly, if restructuring produced the desired result of lower electricity prices, many observers suggested that an increase in electricity demand would lead to more generation and higher emissions. The counterargument was that restructuring would lead to product differentiation and customer choice, including the opportunity for customers to willingly select “green electricity.”

In this paper we review the prospective literature on the possible or anticipated effects of restructuring on the environment and the evidence from changes in the intervening years to utilization of coal facilities, performance of existing nuclear plants, investment in natural gas generation, and electricity prices. We assess how actual experience compares with prior expectations. We discuss other changes in upstream fuel markets, energy policy, and environmental regulations and the role that each of these factors plays in the efforts to evaluate the environmental effects of restructuring. Today the movement toward restructuring has stalled, leaving the country divided into competitive and regulated regions. We discuss the implications of this division for the future of environmental policy and the complicated relationships between policy agendas concerning mitigation of climate change and further restructuring of the electricity industry.

Key Words: electricity, electric utilities, regulation, competition, environment, air pollution, natural gas, coal, nuclear, renewables, customer choice

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Contents

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1. Introduction

In the mid-1990s, when the Federal Energy Regulatory Commission (FERC) was preparing to release Order 888 requiring open access to the transmission grid, FERC, environmental groups, and the Environmental Protection Agency (EPA), among others, raised the question of how open access and greater competition in wholesale electricity markets might affect the environment. If open access worked as expected, underutilized older coal-fired generators in the Midwest and elsewhere might open new markets for their power, leading to associated increases in air pollution emissions. Restructuring also might lead to retirements of inefficient nuclear facilities, whose generation would be replaced by fossil generation, further increasing emissions. On the other hand, some suggested that in the long run, the anticipated increase in investment in new gas-fired generators might accelerate a switch from coal to gas that would decrease emissions. Lastly, if restructuring produced the desired result of lower electricity prices, many observers suggested that an increase in electricity demand would lead to more generation and higher emissions.

In addition to potential direct effects on emissions from electricity generators, electricity restructuring also could have implications for the effectiveness and costs of environmental policies. Incentives for complying with environmental regulations, particularly flexible incentive-based regulations, will vary depending on whether an electricity supplier is subject to price regulation or not. Given that the country is currently divided between states that are restructured and those that are not, variations across these states in the effect of regulations such as pollution cap-and-trade approaches on electricity prices could have important implications for the political economy of new environmental initiatives facing the electricity sector.

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In this paper we look at all of these important issues. Following a brief summary of the major policy initiatives related to electricity restructuring at both the wholesale and the retail levels, we review the prior literature on how electricity restructuring was expected to affect emissions through many different potential factors and influences. Then, we assess how actual experience compares with prior expectations and, where possible, draw conclusions about likely effects on the environment. We also discuss changes in upstream fuel markets, energy policy, and environmental regulations and the role that each of these factors plays in the efforts to evaluate the environmental effects of restructuring. Today the movement toward restructuring has stalled, leaving the country divided into competitive and regulated regions. We discuss the implications of this division for the future of environmental policy and the complicated relationships between the policy agendas concerning mitigation of climate change and further restructuring of the electricity industry.

2. Overview of Electricity Restructuring

It is difficult to pinpoint when the restructuring of U.S. electricity markets began. Some have argued that a major milestone in the process of electricity restructuring was the passage of the Public Utility Regulatory Policies Act of 1978, which included the requirement that regulated utilities purchase electricity from certain types of renewable generators and other “qualifying facilities” at prices that were at or below the avoided cost of generating that electricity oneself (Brennan et al. 1996). The importance of the provision as a precursor to restructuring is that it offered the first significant departure from the legitimate monopoly franchise of electricity generation by regulated utilities. The practical implications of this provision varied across the states, but in states where the avoided cost of generation was set during periods of high fuel costs, qualifying facilities were constructed and the acquisition of power from these independent generators by utilities began in earnest. Contrary to prior fears about the loss of coordination associated with separating the ownership of generation from the ownership of utilities, the integration of purchased power into the mix of generation supplied by the vertically integrated utilities generally worked well. The success of this power purchasing activity, albeit sometimes at prices that turned out to be too high by market standards, demonstrated that separating generation from the power delivery system could work.

The Energy Policy Act of 1992 was the major impetus for subsequent regulatory orders requiring transmission-owning utilities regulated by FERC to provide open and nondiscriminatory access to their transmission lines to facilitate wholesale power transactions.

Open transmission access is a necessary condition for competing generators to get their power to either wholesale or retail customers.[1] FERC implemented this law in two regulatory orders:

- Orders 888 and 889, issued in 1996, set forth the rules defining and governing open transmission access and the requirement for a centralized electronic bulletin board for sharing information about transmission availability and cost with potential customers.
- Order 2000, issued in 1999, built on Order 888 by requiring utilities to actively consider participating in a regional transmission organization (RTO), an independent entity that operates the transmission grid and seeks to prevent discrimination by the transmission owner against competing electricity generators. The structure and rules of any RTO (except the one in Texas, which is outside FERC jurisdiction) are subject to FERC approval and oversight.

Despite those FERC rulings, utilities in several states, including those in the Southeast, do not yet participate in an RTO, and wholesale competition is still more of an aspiration than a reality.

At the same time that FERC was paving the way for more effective wholesale competition, several states were actively seeking ways to provide real choice of electricity supplier to retail customers.[2] The push for retail competition started in states where prices were relatively high, including California, New York, and Massachusetts, and competition was seen as a way of lowering prices.[3] In both California and Massachusetts, retail competition was enabled by legislation and took effect in 1998. In New York, retail competition was implemented through separate agreements between the state utility regulator and individual utilities. Pennsylvania started to allow competition in 1999, and its program was phased in to include all classes of customers by January 2001. Texas passed a law in 1999 that required retail competition to begin in 2002. In all of these states except Pennsylvania and Texas, the restructuring legislation or regulation required that a substantial fraction of electricity generation previously owned by

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[1] For a discussion of the importance of open transmission access see Brennan et al. (2002).

[2] Although retail restructuring in practice has been a state jurisdicational issue, during the Clinton administration there was an effort to make retail competition a national policy. The Comprehensive Electricity Competition Act, introduced by Senator Murkowski in 1999, would have required all states either to adopt retail competition by January 2003 or to formally and publicly demonstrate why this would not be a wise policy. This proposal was a creation of the Clinton administration and it died when that administration left office.

[3] For a discussion of the factors that lead states to be early movers on electricity restructuring, see Ando and Palmer (1998).

integrated utilities be sold to merchant generators. In Texas only 15% of existing capacity had to be sold.

A major issue raised by existing utilities during the debates over electricity restructuring was the desire to recover the sunk costs of past utility investments that might not be profitable in competitive markets. Utilities argued that they had made these investments often at the behest of regulators and typically with their approval, and it would be unfair for their shareholders to now have to bear the costs of investments that had become uneconomic because of a policy change. Compensating utilities for the vast majority of their stranded costs proved crucial to moving restructuring forward, as demonstrated by the case of New Hampshire, where one of the first restructuring laws was passed in 1996 and then tied up in court for several years because it allowed for only partial recovery of stranded cost. The mechanisms chosen to facilitate stranded cost recovery typically involved imposing a nonbypassable charge on electricity distribution service so that all customers would be contributing to recovery of these costs. Typically, mechanisms for recovering these costs put surcharges in place for several years and then eliminated them once stranded costs were recovered. In many cases these costs were actually recovered more quickly than initially anticipated because of a combination of high sales prices obtained for divested generating assets and higher-than-expected wholesale electricity prices.

During the transition period between price regulation and open competition, regulators set retail price caps or default service rates to protect customers from high prices and to provide a backup source of electricity should a competitive provider go out of business or decide to leave the market. The prices for these transition services were typically lower than the regulated electricity price in effect prior to restructuring. In some cases this default service price proved too low to cover the wholesale market price of generation, which in many cases exceeded expectations because of higher fuel prices.

By the end of 2001, 16 states plus the District of Columbia had passed laws or regulations introducing retail competition to their electricity markets for all customers, and most were well on their way to implementing these changes.[4] Missing from this set of 16 states was California, one of the first states to introduce restructuring. After a summer of high prices and rolling blackouts in 2000 and widespread anticipation of more blackouts in summer 2001, the

[4] Oregon passed a law in 2000 requiring customer choice for all industrial and commercial customers, but not for residential customers. For more information, see http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf (accessed February 3, 2005).

Public Utility Commission of California declared an end to retail choice in September 2001. As Brennan (2001) points out, many factors contributed to the problems experienced in 2000, but much of the blame has been laid at the door of electricity restructuring and the problems with specific design features of the California energy market.

The failure of the California market has dampened enthusiasm for electricity restructuring in other states. Since 2001, no additional states have adopted restructuring, and plans to advance restructuring in Oklahoma and West Virginia were put on indefinite hold. However, with the exception of California, no state that was allowing retail choice in 2001 has retreated from that policy choice. Thus, according to the Energy Information Administration (EIA), the United States remains a country divided between those 16 states plus the District of Columbia that have retail choice and the remaining 34 that do not.

3. Ex Ante Predictions of the Environmental Effects of Restructuring

In the mid-1990s, as the rules for wholesale restructuring were taking shape at FERC and some states were charting the course for retail electricity restructuring within their boundaries, there was much interest in assessing the potential environmental effects of these major regulatory changes. Most of the interest focused on the consequences of restructuring for air pollution. Electricity generation contributes 68% of the nation's emissions of sulfur dioxide (SO_2), which contributes to acid rain and concentrations of fine particulates in the atmosphere and reduces visibility. Electricity contributes 22% of the nation's nitrogen oxides (NO_x), which have similar effects as SO_2 but are additionally a precursor of atmospheric ozone. Electricity also accounts for about 40% of the nation's emissions of mercury, a hazardous air pollutant that accumulates in the food supply and contributes to neurological disorders in children, and the sector is responsible for 40% of all U.S. emissions of carbon dioxide (CO_2), one of the most important greenhouse gases. [5]

The relationship between electricity restructuring and emissions of these air pollutants depends on multiple factors that may have countervailing influences.[6] These factors can be classified into two groups: supply-side and demand-side influences. Analyses of the potential

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[5] EPA Current Emissions Trend Data Base at http://www.epa.gov/ttn/chief/trends/.

[6] See Palmer (1997), Palmer (2001), Brennan et al. (1996) and Burtraw et al. (2001b) for more discussion of the many ways that electricity restructuring could affect air emissions from the electricity sector.

effects of restructuring have tended to focus on a few selected factors, but a few have attempted to analyze them all together. The next two sections review what the literature said about the likely effects of these factors on the environment as the process of restructuring was beginning. In a subsequent section we discuss what experience since the advent of restructuring suggests about the effects of restructuring on the roles of different technologies and fuels and on the size and shape of the overall electricity market.

Supply-Side Factors

Effects on Trade and Utilization of Older Coal-Fired Facilities

Before issuing the final versions of Orders 888 and 889 in 1996 and Order 2000 in 1999, FERC undertook environmental impact studies to analyze how greater opportunities for interregional electricity trade under these rules might affect air emissions from electricity generators. During the debate over these regulatory rules, environmentalists raised concerns that emissions from the electricity sector might rise with open transmission access. By providing greater access to markets in the East, the open-access rules might cause older and underutilized coal-fired generators in the Ohio Valley, most of which were built before implementation of new source performance standards under the 1970 Clean Air Act, to increase their generation and thus increase their emissions of NO_x, SO_2, mercury, and CO_2. This possibility led some to suggest that the open-access rules be accompanied by additional regulations to mitigate potential emissions increases (Rosen et al. 1995).

Analyses and simulation studies suggest a range of possible effects of electricity restructuring on the role of coal-fired generation and emissions. These studies focus largely on emissions of NO_x and CO_2, because emissions of SO_2 are capped under Title IV of the Clean Air Act Amendments of 1990 and because monitoring of mercury emissions in the 1990s was very sketchy. Several studies, including those by Lee and Darani (1996), the Center for Clean Air Policy (1996a, 1996b, 1996c) 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 1996) 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. Palmer and Burtraw (1997) find emissions increases roughly in the middle of the range of increases found in the other studies.

One reason for the differences between the findings of the government studies of the FERC orders and the other studies is scope. The former focus on the very narrow question of how the FERC rules are likely to affect emissions and assume that there is no change in final demand for electricity and no change in transmission capacity. Studies that take a broader perspective and look beyond the effects of the open-access orders alone to the effects of restructuring at both the wholesale and the retail levels have tended to find more significant effects on the use of coal-fired power plants and thus on emissions.

A major factor in predictions about the likely effects of restructuring on emissions of NO_x is the underlying assumptions. Virtually none of the studies done prior to the open-access rules anticipated the role of the seasonal cap on summertime NO_x emissions created as a result of the Ozone Transport Region NO_x budget cap-and-trade program that began in 1999, and the subsequent much larger cap-and-trade program that created a five-month summertime cap on NO_x emissions from electricity generators in 19 states in the eastern United States—the state implementation plan (SIP) region. The SIP Call program ultimately came into force in summer 2004. Palmer et al. (2002) conduct a simulation study that looks at the effects on emissions in 2008 of expanding restructured electricity markets from roughly a third of the country to the entire country. They find that in the absence of the NO_x SIP Call, coal-fired generation in the NO_x SIP region rises by 14% and total emissions of NO_x and CO_2 rise by 12% and 2%, respectively. When the NO_x SIP Call is imposed in both the baseline one-third and the national restructuring scenarios, the increase in NO_x emissions in the region falls by roughly half. Moreover, when the seasonal restrictions on NO_x emissions under the NO_x SIP Call are extended to year-round, as they would be under currently proposed regulation, the increase in NO_x emissions resulting from restructuring virtually disappears.

Investment in Natural Gas

In the mid-1990s natural gas–fired generation accounted for roughly 13% of total electricity generation in the United States. Natural gas and dual-fueled capacity (generators that burn either natural gas or coal) accounted for closer to 25% of total capacity. This difference in generation and capacity shares is attributable to the fact that existing gas-fired generators are used primarily to meet peak loads and thus have low capacity factors.[7]

[7] A capacity factor is the ratio of the amount of electricity generated at a facility during a year to the total amount of electricity that could be generated if the facility were run at full summertime capacity 100% of the time.

An important objective of restructuring was the creation of competitive wholesale electricity markets with open access for all generators, including independent power producers that previously had a difficult time gaining access to the market and to the transmission facilities necessary to deliver power to customers. Many observers expected that by reducing or eliminating these barriers, restructuring might hasten the introduction of new gas generators and the switch from a predominantly coal-fired fleet of electricity generators to a greater role for natural gas. Regulators exhibited some risk aversion with regard to potentially volatile natural gas prices and the potential effect of that volatility on electricity prices should the gas share of generation increase (Jennings 1994). Indeed, in England electricity restructuring was accompanied by a large switch away from coal and toward natural gas as the fuel of choice (Burtraw et al. 2001c). However, in England the move to competitive electricity markets was accompanied by a deregulation of coal prices that made gas generation more attractive independent of the changes in electricity markets.

The transition from coal to gas anticipated with restructuring was not expected to be instantaneous but to happen over time, with increases in coal-fired generation and associated emissions as a short-term result. Acceleration of the introduction of new gas facilities into the generation mix was forecast to lead to a midterm to longer-run negative effect on emissions of uncapped pollutants, including NO_x, mercury, and CO_2. The emissions per unit of electricity generation differ significantly between coal and gas-fired electricity generation, and especially between existing coal and new combined-cycle natural gas units. Gas-fired generation has no emissions of mercury and SO_2, and its emissions of NO_x are about 20% of those of an existing coal plant without postcombustion controls. A gas-fired facility has CO_2 emissions that are about 38% of those of an existing, relatively efficient coal facility.

Nuclear

Nuclear power contributes roughly 20% of total U.S. electricity generation, making nuclear the second-largest source of electricity supply. Nuclear plants have no emissions of conventional air pollutants and do no emit CO_2 or other greenhouse gases and thus are considered relatively clean from a traditional air pollution perspective.[8] In the mid-1990s

[8] Fuel processing and transportation account for small emissions of CO_2. Nuclear generators do emit small amounts of radionuclides into the atomsphere, and the production of nuclear power raises a major challenge—how to manage the plants' high-level radioactive waste, which will remain dangerous for centuries to come.

electricity restructuring was expected to hasten the retirement of a sizable fraction of existing nuclear capacity in the United States because of the anticipated inability of these plants to compete at market-determined prices for electricity. The high cost of meeting Nuclear Regulatory Commission safety requirements and the relatively poor performance of several nuclear plants that spent many months off-line for various reasons suggested that these plants would not be able to cover their operating and going-forward capital costs at market prices. As a result, they were expected to retire before the expiration of their operating licenses. These retirements would not be expected under cost-of-service regulation, which generally permits generators to recover their costs in electric rates.

Estimates of the amount of annual nuclear generation that might be lost to early retirement have covered a wide range. Rothwell (2000) estimated that as many as 33 nuclear generating units, roughly a third of the total fleet, were at risk of retiring early. Most of these retirements were expected to occur in regions with predicted low systemwide marginal costs of generation and thus low expected competitive prices. This early retirement of nuclear capacity would have meant a loss of up to 200 Terawatthours (TWh) of generation in 2005, or 30% of total nuclear generation predicted for 2005 under average cost price regulation. Associated with this potential drop in generation is a substantial increase in CO_2 emissions as fossil fuel generators are run more intensively and new units are brought on line to replace the lost generation.

Those ex ante estimates of potential nuclear plant retirements take the costs and performance of existing nuclear plants as given. This estimate ignores the potential for greater competition to lead nuclear plants to improve their performance and increase their generation. Such a development could make early retirements of nuclear plants less prevalent and reduce the potential increases in emissions associated with substituting away from nuclear.

Nonhydro Renewables

In the electricity sector, renewable energy technologies include wind power, geothermal power, hydropower, biomass, landfill gas, and solar power. Currently hydroelectric power is by far the largest component of renewable electricity generation, but with few exceptions, new investment in hydropower is not expected in the future, as hydro development raises a host of environmental issues and local opposition. Renewables excluding hydroelectric power constitute less than 2% of annual generation in the United States in recent years. With the exception of biomass and landfill gas, renewables typically have no emissions of air pollution, and even biomass generators can be part of integrated fuel production systems that produce essentially zero net emissions of CO_2.[9]

The anticipated effects of restructuring on investment in new renewables and use of renewables to generate electricity reported in the literature have been mixed.[10] On the one hand, the move toward greater consumer choice has been seen as a way to allow consumers to express demand for green power in the marketplace, and some consumer surveys have suggested that as many as 50% to 95% of electricity consumers are willing to pay a premium to purchase renewable energy. Analysts have cautioned that the share of customers actually willing to pay more for green power may be closer to 10% to 20%, but in any case, to a greater or lesser degree some see investment in renewables growing under restructuring in response to successful green power marketing (Hirsch and Serchuk 1999; Mayer et al. 1999).

On the other hand, the fact that renewables are typically a more expensive source of electricity generation than existing coal or new natural gas means that renewables might fare less well under restructuring. In many states, renewable generators were built under state regulatory programs designed to encourage use of low-emitting sources or in response to requirements of the Public Utility Regulatory Policies Act of 1978 that utilities purchase power from renewables at prices below avoided cost. As a growing component of the electricity supply sector becomes deregulated, programs such as these would become less viable, and the associated incentives to invest in new renewables would diminish as well.

Demand-Side Factors

Price Level and Demand Response

A primary motivation for electricity restructuring is to lower both wholesale and retail electricity prices. The thinking is that competition will make generating firms more efficient and lead to reductions in the cost of generation, which in turn will translate into lower electricity

[9] This ignores emissions associated with transport of the fuel from where it is grown to the electricity generator. These emissions are typically ignored for other fuel cycles as well.

[10] There also has been speculation about how restructuring in the electricity sector in developing countries would affect the environment in general, and the fate of renewable technologies in particular (Kozloff 1998).

prices. As price falls, total demand for electricity is expected to rise, and holding the mix of generation technologies constant, so are emissions.[11]

Price declines on average do not mean price declines everywhere. In some regions of the country, electricity rates have been relatively low under regulation, because of either very efficient regulation or the availability of low-cost generating resources, such as hydroelectric dams. In those regions, prices could rise if restructuring provides generators with the option of selling their electricity into broader regional markets where prices set at marginal cost would likely exceed the low average cost of the native generators. Thus, the effect of restructuring on electricity price depends on the relative performance of the generators prior to restructuring.

The predicted effects of restructuring on the average national price of electricity have ranged from a decline of 2% (Palmer et al. 2002) to a drop of 40% (Berkman and Griffes 1995), with the higher estimate being somewhat of an outlier. Assuming a relatively conservative elasticity of demand of –0.15% would suggest that the associated increases in electricity demand would range from 0.3% to 6.0%. Demand increases at the higher end would surely have adverse effects on emissions of noncapped pollutants, although the extent of those increases would depend on the relative roles of gas, nuclear, coal-fired, or renewable generation in meeting this increment in demand. Even in the presence of emissions caps, demand increases could result in regional shifts in pollution, with potential environmental consequences.

Price Structure and Demand Response

Many industry observers predicted that electricity restructuring would lead to greater use of real-time pricing of electricity in retail markets. Greater reliance on spot-market transactions at the wholesale level coupled with greater desire to differentiate products for competitive purposes could provide a stronger incentive to offer real-time electricity prices to customers who are in a position to manage the risk of price fluctuations in exchange for lower rates. The environmental effects of a change from time-invariant electricity prices to greater time differentiation depend on the fuel mix of peak versus baseload generation.[12] If peak-load pricing

[11]This argument does not necessarily imply an increased need for regulation. Brennan (1999) shows that the size of the economic social welfare loss associated with unregulated or underregulated emissions from electricity generators could increase or decrease as the cost of generating electricity falls, depending on the relative slopes of the demand and supply curves for electricity.

[12] Holland and Mansur (2004) find that the effect of reduced variance in demand (a consequence of real-time pricing) on emissions varies across regions of the country.

tends to shift demand from peak periods to base periods and baseload generators are mostly coal-fired, then this shift could lead to an increase in emissions. However, some of the environmental consequences of higher emissions at night might be less severe than for emissions during the day. This is especially true for emissions of NO_x, which is a precursor to ground-level ozone when combined with sunlight.[13]

In an analysis of the effects of real-time pricing for industrial customers only, Palmer et al. (2002) find that eliminating real-time pricing for industrial customers reduces the increase in NO_x emissions that would result from more widespread restructuring by 25% and reduces the increase in CO_2 emissions by almost 50%.[14] Eliminating real-time pricing shifts more demand from off-peak periods back to peak periods and thus shifts the mix of generation more toward gas and away from coal, with associated reductions in the emissions impacts of restructuring.

Demand-Side Management and Conservation

In the mid- to late 1980s and early 1990s, utility regulators in several states were actively encouraging the electric utilities under their jurisdiction to pursue cost-effective programs to reduce electricity demand or to shift demand away from peak periods. In some states, decisions about which demand-side management (DSM) or conservation programs to pursue were integrated with decisions about investment in new generating capacity under the rubric of integrated resource planning. Under this planning process, utilities would evaluate investments that promised reductions in current (or future) electricity use against investments in new generation capacity to find the most cost-effective approach to satisfy new demand. By reducing the need for generation, these programs were also seen as a way to reduce the adverse environmental effects of the electricity sector.

With the move toward restructuring and deregulation of the generation and retail sales parts of the electricity supply business, many anticipated the demise of integrated resource planning and utility DSM programs. Absent the push from regulators, independent generators or retail electricity suppliers would not have sufficient incentive to continue these programs, and future conservation efforts would fall short of those in the past.

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[13] Nighttime emissions of NO_x may be roughly one-third as potent as daytime emissions in contributing to ozone formation (Bharvirkar et al. 2003)

[14] See Table 13 in Palmer et al. (2002).

However, others anticipated that instead of regulator-mandated programs for DSM, the restructured industry could see an influx of energy services companies that would help large electricity consumers find ways to save electricity in exchange for a portion of those savings (Bohi and Palmer 1996). Thus DSM would become more of a private enterprise and less of a regulatory program. How fast this would happen would depend on what happened with electricity prices and the costs of energy-saving equipment.

4. Evidence on the Effects of Restructuring

More than 10 years has passed since the signing into law of the Electric Policy Act of 1992; FERC Order 888 is almost nine years old, and many states, including, for example, Maryland and New Jersey, have completed the initial multiyear transition period envisioned in their restructuring laws and enabling regulations. Thus, this is a natural juncture at which to look back at what has happened in this early phase of restructuring and get some sense of how restructuring has affected the electricity sector and its impact on air quality.

In this section of the paper we discuss the "evidence" regarding the effects of electricity restructuring on the many supply- and demand-side factors identified above, as well as the role of additional factors that have complicated the landscape since restructuring began. The evidence presented takes the form of a descriptive analysis—preliminary in nature because in most regions that have undergone restructuring, the transition to competitive markets is still underway. Arguably, the transition to open transmission access and truly competitive wholesale markets is continuing as well. This descriptive analysis relies largely on simple descriptive statistics and graphs in lieu of a more formal statistical analysis of the role of restructuring and other factors in the data trends presented. In some cases formal statistical analyses do exist, and we present those findings.

Coal Plant Utilization

Have the predictions that restructuring could lead to increased utilization of coal-fired generators, particularly older, high-emitting plants in the Midwest, been realized? This is a difficult question to answer using readily accessible data, but some trends are evident. First, Figure 1 shows that the average capacity factor for the entire fleet of coal-fired generators in the United States rose from roughly 60% in 1992 to 70% in 2002. Moreover, the rate of increase rose after 1995, coincident with the genesis of restructuring activity at FERC and in several states. The figure shows a virtually identical trend in average capacity factors at coal-fired units in the Ohio Valley region, home to many of the oldest coal-fired generation facilities in the nation.

However, the figure also shows that the national average capacity factor at coal plants also rose between 1981 and 1992. Using a simple trend regression analysis on the 1981 to 1992 national average capacity factor data to forecast to 2002 suggests that the post-1992 growth trend is roughly identical to the pre-1992 trend. This finding suggests that restructuring may not be contributing to an increase in capacity factors at coal plants. However, there are other factors that differentiate the earlier decade from the later one that need to be taken into account. Some of the upward trend during the 1980s was likely due to the influx of newer coal-fired generators, which added close to 60 gigawatts (GW) as new coal-fired capacity came on line and tended to raise the average capacity factor of the entire coal fleet as represented in the graph. The building of new coal plants slowed dramatically during the 1990s, and thus newer facilities were not being infused into the mix of vintages of coal plants during that decade. Nonetheless, capacity factors did rise, particularly after 1996, the year FERC issued Orders 888 and 889.

In addition to restructuring, another factor that likely has contributed to the increase in generation and capacity factors from coal-fired facilities is the rise in the price of natural gas. Figure 1 shows that the increase in average capacity factor at coal-fired plants is also coincident with a rather dramatic runup in the wellhead price of natural gas. This increase in the price of an alterative fuel could be a major contributing factor to the increase in generation from existing coal plants in recent years.[15]

Nuclear Retirement and Generation

One of the unexpected consequences of electricity restructuring and greater competition in wholesale electricity markets is the substantial improvement in performance at the nation’s nuclear plants. Contrary to predictions that many nuclear plants were at risk of retiring prior to their license expiration as a result of competitive pricing of electricity, nuclear units, for the most part, have thrived under competition.

[15] High natural gas prices contributed to a continued increase in coal-fired generation in 2003 and, according to EPA, also contributed an increase in annual emissions of SO_2 relative to 2002 (U.S. EPA 2004), facilitated by the use of banked allowances from Phase I.

Since the passage of the Energy Policy Act in 1992, only eight nuclear reactors totaling just less than 6 GW of capacity have been shut down. These commercial reactors are listed in Table 1. Notably, these plants account for only about 6% of total nuclear capacity in 1992, far below the upper limit of the predictions that 30% of existing capacity might retire as a result of restructuring.

Instead of faring poorly under restructuring, existing nuclear plants are actually thriving and producing more than ever. Figure 2 shows that even though only one new nuclear generator has been brought on line since the mid-1990s, total generation at U.S. nuclear plants has risen by close to one-third between the early 1990s and 2003, with most of that increase occurring in the most recent years. Moreover, preliminary data through November 2004 suggest that nuclear generation achieved an all-time high in that year.[16] Figure 3 shows the associated and substantial increases in capacity factors at the nation's nuclear plants in recent years.

This group of findings is consistent with the incentives created by greater competition. Given the large quasi-fixed costs associated with nuclear technology, it makes sense for a plant operator to try to reduce per MWh generation cost by increasing the amount of generation at the plant. Under cost-of-service regulation, incentives to increase productivity at nuclear plants were much more muted, since revenues were a function of cost. Reductions in cost would lead to an increase in net revenues (profits) during time periods when costs were otherwise not increasing and rate case adjustments to electricity prices did not occur. In other words, the reward to reducing costs depended on "regulatory lag" —the delay in adjusting revenues to match costs (Joskow 1974). However, reductions in cost would not be rewarded to the same degree that they are under competition.

Recent increases in nuclear generation have come about through a combination of reductions in scheduled and forced outages at U.S. plants and through investments that have led to incremental increases in capacity at existing plants. These investments, which range from changes in instrumentation settings to replacement of major components such as high-pressure turbines, pumps, and generators, increase the capacity rating of existing facilities and therefore are referred to as nuclear uprates.

[16] See EIA's most recent analysis of nuclear electricity generation in the United States at http://www.eia.doe.gov/cneaf/nuclear/page/nuc_generation/gensum.html (accessed February 4, 2005).

The relationships between both capacity factor increases and investments in new equipment at nuclear plants and electricity restructuring have been investigated by Zhang (2005). The Zhang analysis suggests that from 1992 through 1998, the extent of restructuring or market deregulation within a state had a positive effect both on plant capacity factors and on the level of additional investment at existing plants. These findings are consistent with the hypothesis that restructuring has been a positive force for productivity improvements at the nation's nuclear plants.

Growth in electricity generation at U.S. nuclear plants has clearly had some positive effects on the environment. If the observed increases in nuclear generation had not taken place, then generation from fossil facilities would have made up some of the difference, resulting in higher emissions. To some degree, at least, it is apparent that the incentives provided by restructuring did not lead to the retirement that some anticipated; instead, they have contributed to expanded generation by nuclear plants.

Gas Investment

Since 2000 there has been a dramatic increase in investment in new gas-fired capacity, including both new gas single-cycle turbines and new gas combined-cycle units. The amount of new gas capacity added in 2001 and 2002 dwarfs new natural gas capacity installed in any prior year. The amount of gas capacity that was planned in 2002 to be brought on line in both 2003 and 2004 exceeds total additions of capacity of all types in all prior years, as shown in Figure 4. This massive amount of entry of natural gas capacity in response to the opening up of electricity markets can be characterized as an overbuild—that is, an uncoordinated influx of investment that exceeded market opportunity. The massive new natural gas generation capacity has led to very high capacity margins in certain parts of the country, with summer reserve margins in the Northeast exceeding 23% in 2003 and exceeding 20% in the Ohio Valley and in Texas.[17] Not only has restructuring increased investment in new gas capacity, but also it has changed the nature of investment in gas turbines. According to Ishii (2004), the expansion of restructuring has brought about a shift in technology choice in the realm of gas turbines away from smaller turbines toward higher-capacity turbines that are better suited for combined-cycle, baseload

[17] Capacity margin is the ratio of total capacity installed to peak demand levels. See U.S. EIA, Electric Power Annual 2003, Table 3.3, at http://www.eia.doe.gov/cneaf/electricity/epa/epat3p3.html (accessed February 8, 2005).

application, can operate over more hours of the year, and would compete with baseload coal and nuclear units.

As a result of the overbuild, total gas-fired capacity exceeds current generation needs by a substantial margin, and therefore many of the new plants are operating at low capacity factors. The high price of natural gas, which makes generating with natural gas relatively less attractive than using coal for baseload generation, also contributes to low capacity factors at new gas plants. In peak periods, gas turbine technology is the marginal technology; electricity price is tied to short-run variable costs at these units and is therefore tightly dependent on natural gas price. Were it not for the overbuild in natural gas capacity, the peak-period price would provide revenue to offset the capital cost of new combined-cycle generation, but because of low capacity factors, these units are not earning expected revenue over all times of day. Furthermore, the environment of overcapacity means that there is no room for recovery of capital cost of gas turbines, even during the peak. Were capacity constrained, electricity price would be expected to rise above the short-run variable cost for new efficient gas turbines and begin to reflect long-run marginal cost, or equivalently, the variable cost of older and less efficient gas and oil-fired turbines.

Two offsetting factors resulting from the overbuild in natural gas generation affect the environment. One is the accelerated expansion of natural gas–fired capacity, attributable to a significant degree to restructuring and the perceived opportunity to earn profits in excess of regulated levels. This perception made what had been characterized as a mid-term or long-term transition in generation capacity begin to be realized much faster than expected. In isolation, this trend would have led to lower emissions and unambiguous environmental gains. The offsetting factor was the largely unanticipated runup in natural gas price since 1999 (Figure 1), which extended the economic advantage of existing coal-fired facilities. By and large, it is difficult to assert that the runup in natural gas price is attributable to the increase in gas-fired generation capacity in the electricity sector because the sector represents only 25% of total demand for natural gas in the United States. Rather, the increase in natural gas price appears to be largely due to factors outside electricity restructuring, and the associated increase in coal-fired generation and related effect on emissions would have been felt even in the absence of restructuring.

Renewables

The increase in market demand for green power that some had predicted would result from restructuring has yet to materialize. Bird and Swezy (2004) find that the green power market is only a small portion of the total electricity market. Looking at green power offerings from both utilities and competitive electricity suppliers, they find that, on average, just over 1% of all utility customers participate in some form of utility-offered green pricing program, and the vast majority of these are residential customers. A second source of green power comes from nonregulated companies, such as Green Mountain Energy, that aggregate electricity supply and offer portfolios to electricity customers that have specific environmental attributes. Bird and Swezy estimate that adding in their estimates of total green power customers from surveys of green power marketers raises the percentage of total utility customers participating in some form of green pricing program, but it is still less than 1.9% of all customers. Thus most of the increase in “voluntary” green power sales has been in response to utility-sponsored choice programs, many of which have been required by regulators, and less a result of retail market forces that emerged as a consequence of restructuring.

Despite the very limited success of green power marketing, renewables have gained some ground in the era of restructuring. Most of the states that have moved forward with restructuring (and several that have not) have adopted new policies to promote use of renewable generating technologies during the transition to competition. One of the most popular policies is what is known as a renewable portfolio standard (RPS). Under an RPS policy, a certain minimum percentage of electricity either generated or sold within the utility or at the state level must be generated using a renewable technology. Typically, this minimum percentage starts out small and grows over time. Since the mid-1990s, 18 states and the District of Columbia have adopted RPS policies.[18]

Whether as a result of an RPS or private green power marketing initiatives, the environmental effects of increased renewables generation are not as large as some have predicted. Simple estimates of the emissions reduction effects of greater renewables generation have often used the average emissions rate across the entire fleet of generation within the relevant jurisdiction. This approach is explicitly assuming that, holding total generation constant,

[18] In Pennsylvania, the recently adopted standard is actually an alternative energy portfolio standard, and it includes waste coal generation in the mix.

all fossil generation is reduced in proportion to its share of the generation mix with the introduction of increased renewables. However, renewables do not displace fossil generators in this manner. Palmer and Burtraw (2004, 2005) have shown that new renewables tend to back out largely generation from gas-fired facilities, especially new facilities, and thus the emissions reductions for CO_2 and NO_x will be smaller than others have estimated. Increased renewables will not reduce emissions of capped pollutants such as SO_2 either nationwide or within states that have caps, such as New York, unless the magnitude of the renewables requirement is so large that it causes aggregate emissions to actually fall below the allowable cap.

Electricity Price Levels and Demand

The changes in electricity prices in the early years of electricity restructuring have varied across states and across customer classes and generally have not been as dramatic as some had predicted.[19] Figures 5 through 8 provide an overview of how average nominal retail electricity prices in selected states have moved between 1990 and 2002.[20] In many cases these graphs mask large differences across regions of the state or across time periods in a year, but they give a general flavor of how prices have changed over time during the initial phase of electricity restructuring in several key restructured states. The graphs also provide data for one state that has not restructured, Florida, as well as for California and the United States as a whole.

These graphs provide some insights into why several states may have chosen to restructure. With the exception of Texas, all of the states included in the graphs that moved ahead with restructuring had retail electricity rates for each class of customers and for all customers taken together that were typically well above the national average price.[21] In some cases, such as Pennsylvania and Connecticut, that price gap started to close after restructuring, but for other states, the reduction in the price gap was more fleeting. Also, among the states included in the graph, in most of the states that underwent restructuring (Pennsylvania and Texas are the exceptions), retail electricity prices have tended to vary more over time both before and after restructuring than did prices in Florida or across the nation as a whole.

[19] One way that competition can bring about lower prices is by providing incentives for more efficient productions. Markiewicz et al. (2004) find evidence that restructuring has contributed to improved efficiency at fossil plants.

[20] The states included in these graphs were chosen to illustrate a range of price levels and to cover a range of policies toward price evolution during the early years of restructuring.

[21] Some states not included in the graph, most notably Montana, also had retail rates that were below the national average.

In most cases, the initial price declines shown in these graphs for the restructured states in the late 1990s were the result of retail price caps or low regulated prices for standard-offer service imposed by regulators or by law on utility providers at the time of restructuring. For example, Connecticut imposed a cap on residential prices for standard-offer service at 1996 regulated levels for the first few years of the transition. This cap was followed by a 10% rate reduction to be put into place until 2004, at which point prices would be allowed to rise to encourage market entry with a cap on the ultimate price increase allowed by the end of 2007. These caps were seen as a way of "front loading" the energy cost savings expected to follow naturally from the move to competition. In many states, such as Massachusetts and Maryland, these price caps were expected to be phased out in a few years, as more and more customers shifted to competitive suppliers and competition took the place of price cap regulation as a mechanism for regulating prices.

Unfortunately, the low prices imposed in many states at the outset of restructuring may have served to delay the spread of true retail competition. First, in many states, most notably California but also northeastern states such as Massachusetts, the retail price caps proved too tight to accommodate increases in wholesale electricity prices that accompanied some tight capacity situations in the early days of restructuring, or the wholesale electricity price increases being brought about at least in part by high prices of natural gas. Many utilities were stuck with a new type of stranded cost, since they were unable to recover in capped retail prices the costs of the power procured at rising wholesale rates. With electricity prices set so low, it became difficult for new suppliers to enter the market profitably: they were unable to cover their fuel costs and compete with the low price of standard-offer service from incumbent providers (Rose 2004). Many new entrants went bankrupt or left the market before doing so. Many retail customers who might have been inclined to switch providers were unlikely to do so given the low prices for standard-offer service. As a consequence, the dynamic allocation of customers to providers, the dynamic price competition, and the entry of new providers did not materialize.

Eventually, prices for standard-offer or default electricity service had to be adjusted upward to allow electricity retailers to cover increases in fuel costs reflected in wholesale market prices. This happened fairly quickly in Massachusetts, where a fuel adjustment clause was added to the default service pricing rule. The resulting effect of the runup in natural gas prices in 2001 on wholesale electricity prices is evident in the retail price spike in 2001 shown in the graphs. A milder form of this price spike also seems to have occurred in New York, where prices also trended up in 2000 and 2001 (with a particularly pronounced increase in the commercial sector) and then back down in 2002. In California, increases in residential, commercial, and industrial rates that began in 2001 continued through 2002 as restructuring was abandoned and regulators were trying to set rates that helped secure the economic health of both electricity suppliers and their customers.

What those price trends suggest for electricity demand and emissions is not uniform across the states. Although prices did fall in the early days, they also tended to rise again after 2000, and the size of those price increases varied substantially across states and across customer classes within states. With the exceptions of Pennsylvania and Connecticut, where residential electricity prices have remained fairly low since restructuring, the post-2000 increases in electricity prices have not given consumers a reason to expect sustained low electricity rates in the era of restructuring. As a result of the minimal effect on electricity price from restructuring, demand response to initial price drops is likely to have attenuated a bit, thereby muting any adverse effect on emissions results from higher demand that was anticipated to result.

Electricity Conservation and Demand-Side Management

Utility investments in DSM programs and associated energy savings (Gillingham et al. 2004) fell dramatically during the early years of restructuring as utilities sought to shed costs and compete more effectively with nonutility competitors that did not have such programs. According to data collected by the Energy Information Administration, between 1993 and 1999, annual utility expenditures on DSM programs fell by roughly 55%, and incremental annual energy savings fell by about 65%. Upon restructuring their electricity markets, some states established public benefits funds to support numerous programs, such as research and development of new technologies and energy efficiency investments that many feared would be lost as a result of restructuring. The source of these public benefits funds was charges assessed on all electricity users connected to the local distribution grid. Beginning in 1999, DSM spending by utilities started to increase again as a result of these programs. However, in several cases these programs were funded by state energy agencies or directly by regulators, and thus the role of the traditional utilities in administering these programs was reduced in those states.[22]

[22] For example, in New York State, the system benefits program is administered by the New York State Energy Research and Development Authority (NYSERDA).

Electricity Price Structures

The effect of electricity restructuring on the structure of electricity prices has also not been as dramatic as expected. Real-time pricing, which requires the installation of real-time electricity meters at customers' sites, has been adopted by only a small number of electric utilities, with relatively mixed success. For example, real-time pricing has been employed at Duke Power for large customers and by Georgia Power Company, where roughly 1,600 large commercial and industrial customers pay real-time prices (O'Sheasy 2002). These two programs have been relatively successful, and the Georgia Power program has very low attrition rates (O'Sheasy 2002).

However, another well-publicized experiment—for Puget Sound Energy residential customers—was ended in 2002, less than a year after it started (Glyde 2001). The Puget Sound experiment was not a real-time pricing program but a more moderate scheme, called time-of-use pricing, whereby prices varied in a predetermined manner between specified peak and off-peak periods. Time-of-use pricing was intended to create incentives for load shifting away from peak demand times and toward base periods without exposing customers to potentially large fluctuations in electricity price on an hourly basis. Customers did not save money, and some even wanted to return to flat rates, so the system was abandoned.

None of those major programs in real-time or time-varying pricing took place as part of restructuring in those states. Some states chose to impose real-time pricing on large customers as they entered the second phase of the transition to full restructuring. For example, in New Jersey, the default service price for large commercial and industrial customers who fail to choose a competitive provider by the end of the initial transition period is based on hourly spot market prices from PJM Interconnection (an RTO). In the case of California, real-time pricing was a consequence of the market disruption in 2001 and was implemented by the state.

The failure of the proliferation of real-time pricing should not necessarily be taken as a sign that it is a bad idea. Borenstein (2004) has used a simulation model to show that the benefits from greater use of real-time pricing tend to outweigh the costs. However, the fact that it has not become more widespread to date means that this type of change in pricing structure has not had a big role in shaping the impact of electricity generation on the environment in restructured states or elsewhere.

Emissions and the Effects of Environmental Policies

Table 2 provides an overview of annual emissions trends between 1992 and 2003 for three major pollutants from the electricity sector. This table shows that with the exception of CO_2, emissions from electricity generation have been declining over this roughly 10-year time horizon. SO_2 emissions have fallen by roughly a third and NO_x emissions by more than 40%. The decline in SO_2 emissions will continue into the future as generators draw down the accumulated bank of SO_2 emissions allowances. The sector is expected to reach the annual cap on SO_2 emissions allowances specified in Title IV of the 1990 Clean Air Act Amendments—8.9 million tons per year—by 2010. The cap on annual NO_x emissions is currently limited to electricity generators in the eastern states and only applies in the summer months, and thus total annual emissions of NO_x from this sector could rise as generation increases. Emissions of CO_2, which are unregulated at the federal level, are also expected to rise as electricity demand increases.

Unfortunately, the aggregate time series emissions data tell us virtually nothing about the effects of restructuring on emissions from electricity generators because of the confounding effects of environmental regulation. Prior years do not provide a good counterfactual of what emissions levels or emissions rates would have been in the absence of restructuring. In the case of both SO_2 and, to a lesser extent, NO_x, the emissions caps have virtually guaranteed reductions in emissions over this time period. If restructuring had resulted in increased utilization of existing coal facilities, then we might have expected to see a faster drawdown of the SO_2 allowance bank than the 2010 date originally forecasted (Carlson et al. 2000). However, U.S. EPA (2004) continues to forecast that the large bank of allowances will be exhausted by 2010.

Total emissions of CO_2, which is unregulated at the federal level, track the coal plant capacity factor results shown in Figure 1 very closely. As shown in Table 2, emissions grew through 2000 and then dropped when coal plant utilization dropped in 2001. The pattern of emissions changes over this decade is likely due to a mix of electricity restructuring and fluctuations in the price of natural gas, with the relative contribution of the two factors largely unknown.

Effects of Restructuring on Pollution Cap-and-Trade Programs

Much has been written about how public utility regulation of electric utilities has limited the use of SO_2 allowance markets to achieve cost-effective compliance with the national SO_2 emissions cap established under Title IV.[23] Differential regulatory accounting treatment of scrubbers versus allowance purchases served to reduce interest on the part of regulated utilities in using allowances for compliance (Bohi and Burtraw 1997; Sotkiewicz 2002). Other research suggests that state regulation led to excess reliance on fuel switching instead of allowance trading as a means of compliance (Arimura 2002; Rose 1997). By eliminating some of these regulatory barriers or disincentives to the use of allowance markets, the move from regulation to competition was expected to increase the efficiency of pollution cap and trade programs applied to the electricity sector (Brennan et al. 1996; Carlson et al. 2000).

Evidence on how restructuring has affected the performance of emissions allowance trading is still sparse. U.S. EPA (2004) finds that annual transfers of Title IV SO_2 allowances between economically distinct entities increased dramatically from when the program began through 2000, the beginning of the second phase of the program, and have declined since then, presumably because compliance plans were largely in place. These data suggest that use of the market did increase as experience with allowance markets grew, but the role of restructuring in influencing this trend is difficult to know.

The relationship between restructured electricity markets and pollution allowance markets received wide attention because of the California electricity crisis in summer 2000 and its effect on NO_x allowance prices in Southern California (Brennan 2001c; Burtraw et al. 2005). In 1994, to combat ozone pollution, the South Coast Air Quality Management District launched the first large urban cap-and-trade program for NO_x, known as the Regional Clean Air Incentives Market (RECLAIM). In summer 2000, when electricity capacity was tight in California and older high-emitting generators were called into service to meet peak-level demands, demand for NO_x allowances also rose and the price of NO_x allowances peaked at about $60 per pound, substantially above historical levels. Emissions during that summer exceeded the total allowance allocation. The inability to cope with large increases in demand for NO_x allowances may be due in large part to the lack of allowance banking in the RECLAIM program that would have

[23] Much of this literature is reviewed in Burtraw et al. (2005).

provided a cushion of allowances to help fill the gap in supply during periods of high demand (Burtraw et al. 2005).

Another strand of literature focuses on the potential relationship between allowance markets and the exercise of market power in electricity markets. In many cases, deregulated electricity generation markets function more as oligopolistic markets, with small numbers of competitors, than as perfectly competitive markets. In oligopolistic markets, individual suppliers can have some influence over the market price, and their incentives to behave strategically to raise prices could have implications for emissions and for outcomes under cap-and-trade programs. Mansur (2004) investigates the reasons behind a substantial drop in regional emissions of both SO_2 and NO_x in the mid-Atlantic states between 1998 and 1999. He finds that only 64% of the drop in NO_x emissions is attributable to the environmental regulation of NO_x, and roughly 36% of the drop in NO_x emissions can be explained by the exercise of market power by electricity generators. He finds similar results for the drops in regional emissions of SO_2 and CO_2. He also finds that strategic behavior in wholesale electricity markets helps lower the price of NO_x allowances and thus has positive effects on social welfare.

5. Prospects for the Future

Expectations about the large benefits to society from greater competition in electricity markets remain largely unmet, although some gains in efficiency related to generation are evident, particularly for nuclear power. Retail price reductions in states that moved to restructuring were largely the function of regulated transition-period price caps for electricity supplied by distribution utilities or effective price caps in the form of regulated prices for standard-offer service. These low prices limited entry by competitive suppliers, and many suppliers who did enter, unable to make a profit, subsequently withdrew from the market. As initial transition periods end during a time of relatively high natural gas prices, retail electricity prices are tending to rise and people are questioning the wisdom of restructuring in the first place. Still, it may be premature to judge the effects of allowing competition, since transition-period policies may have limited the scope for retail competition during the transition and the real opportunities for market forces to affect retail electricity prices may be yet to come.

Likewise, it may also be too early to tell how restructuring will affect the environment, both because all the data are not out yet and because the initial transition period is just drawing to a close. The general sentiment is that, in part because of lack of options for suppliers for smaller customers, regulators will continue to impose rate freezes or caps on rates paid by smaller customers into the future (Rose 2004).

The lessons from our experience with restructuring to date and our efforts to simulate the potential effects of restructuring in the future suggest that other factors affecting the electricity sector may have bigger effects on the environment and on electricity consumers than the move to competition. In this section we review the likely effects of the different factors.

Other Things Matter More to the Environment Than Competition

Many of the simulation studies that look at the potential effects of more widespread electricity competition and different types of regulatory policies on emissions from electricity generators suggest that policies other than restructuring will play a larger role in influencing the future course of emissions from the sector than will electricity restructuring. These policies include new or anticipated restrictions on emissions of multiple pollutants from the electricity sector, the presence or absence of caps on carbon emissions, and efforts to promote greater use of renewable technologies to supply electricity. Across all of these policy initiatives, the price of natural gas will have an important influence on effectiveness and cost-effectiveness. In this section we address each of these issues in turn.

Multipollutant Policies

The Clean Air Act Amendments of 1990 ushered in a new era of using cap-and-trade approaches to address emissions from electricity generators. The 1990 legislation and subsequent regulations have focused on emissions of SO_2 and NO_x, primarily to address acid rain concerns and ozone pollution. Although these regulations brought about substantial reductions in emissions, they have fallen short of meeting national ambient air quality standards for ozone and particulates and arresting the problems of acidification. Further reductions in both pollutants are clearly justified on cost-benefit grounds from the perspective of the human health benefits alone (Banzhaf et al. 2004).

Several proposals have been introduced over the past few sessions of Congress to impose stricter nationwide caps on emissions of SO_2 and NO_x in the electricity sector and to cap emissions of mercury and, in some cases, CO_2 as well. Three bills that would have regulated multiple pollutants were introduced into the Senate during the 108th Congress (2003–2004). All would use an emissions cap-and-trade program as the primary mechanism for achieving emissions reductions.

The most aggressive plan, the Clean Power Act, introduced by Senator Jeffords (I-VT), proposes to cap annual emissions of SO_2 at 75% below the Title IV cap and annual NO_x emissions at 25% of their 1997 levels by 2009. The bill also caps annual emissions of mercury at 10% of 1999 levels by 2008 and includes a national cap on CO_2 set at 1990 levels beginning in 2009. The bill allows for emissions trading for all gases except mercury.

The Bush administration's Clear Skies proposal, which was introduced by Senators Inhofe (R-OK) and Voinovich (R-OH), caps annual emissions of SO_2 at 50% of the Title IV cap of 9 million tons in 2010, with the cap declining to 30% of the Title IV cap by 2018. Annual emissions of NO_x are capped at roughly one-third of 1997 levels beginning in 2009, and the cap declines to roughly 28% of 1997 levels by 2018. The bill also calls for reductions in annual emissions of mercury of about 50% compared with 1999 levels by 2010 and 70% by in 2018.[24] This proposal permits the trading of emissions allowances for all three pollutants and imposes no cap on CO_2.

In between these two proposals is the Clean Air Planning Act, sponsored by Senator Carper (D-DE). This bill imposes emissions caps for SO_2, NO_x, and mercury and sets timetables for achieving those caps, falling in between the other two proposals. This bill also includes a phased-in cap on CO_2 emissions from electricity generators but allows for the use of emissions offsets from outside the electricity sector. Mercury emissions trading is allowed, although generators must meet facility-specific emissions reduction targets.

Multipollutant legislation had not advanced in Congress as of the end of 2004; however, EPA has taken steps toward requiring greater reductions in emissions of SO_2, NO_x, and mercury. In March 2005, EPA promulgated the Clean Air Interstate Rule (CAIR), which proposes annual caps on emissions of SO_2 and NO_x in 28 eastern states and the District of Columbia. The ultimate percentage reductions in emissions imposed within the CAIR region are comparable to those that would be required nationwide under the Clear Skies legislation, except they happen on a somewhat accelerated schedule. At the same time, EPA issued a rule to limit emissions of mercury using a nationwide mercury cap-and-trade program that would achieve 70% reductions over a longer time frame. .

While legislative and regulatory debates over multipollutant policies continue at the federal level, several states have taken decisive action to address emissions of one or more

[24] The Clear Skies initiative does not include a cap on CO_2 emissions, but instead proposes to cut greenhouse gas intensity on an economy-wide basis by 18% over the next 10 years using mostly voluntary initiatives and providing a formal mechanism for recognizing cuts that are made voluntarily.

pollutants from electricity generators beyond the requirements of federal law. These state policies are summarized in Table 3. Most, such as new regulations in Connecticut and Massachusetts that limit nonozone-season emissions of NO_x, are formulated as emissions rate standards. The largest state action is in North Carolina, which has recently placed emissions caps on its largest coal-fired plants. A similar plan has been adopted in New Hampshire for all existing fossil fuel generators. New York also has caps on emissions of SO_2 and NO_x from large generators within the state as well.

Were the federal policies to be implemented, these multipollutant programs, particularly the national or large regional emissions cap-and-trade programs, would substantially offset any increases in emissions that might result from further expansion of competition and electricity trading. Salient features of these policies include the stringency of the standard for mercury and the form of that standard. Stringent policies to control mercury using a cap-and-trade approach could result in substantial ancillary reductions in SO_2 emissions beyond those required under the CAIR policy, for example.

Carbon Policy

How a multipollutant policy affects investment decisions at electric companies depends in large part on whether the policy includes a cap on emissions of CO_2 (Burtraw and Palmer 2005). In the absence of a CO_2 policy, firms will invest a lot of resources in postcombustion controls at existing coal-fired and gas-fired facilities to reduce emissions of conventional pollutants. Once in place, these long-lived investments will further cement opposition to capping or taxing CO_2 emissions from electricity generators until the capital has depreciated.

If a multipollutant policy includes a cap on CO_2 emissions, the electricity sector will broaden the range of options it considers for reducing the entire basket of pollutants and begin to pay more attention to switching away from coal toward greater use of natural gas and renewables. Including CO_2 will also, depending on the level of the cap, have a greater impact on the price of electricity paid by consumers, which in turn will encourage more energy conservation and efficiency as a way to reduce emissions of greenhouse gases.

Efforts to regulate emissions of CO_2 from the electricity sector have been concentrated at the state and regional level. Massachusetts and New Hampshire have adopted limits on CO_2 emissions from electricity generators. At the invitation of Governor George Pataki of New York, nine northeastern states—Delaware, New Jersey, New York, Connecticut, Massachusetts, Rhode Island, Vermont, New Hampshire, and Maine—have formed the Regional Greenhouse Gas Initiative (RGGI). This group of states is working together to develop a cap-and-trade program for CO_2 emissions from electricity generators within the region. One challenge they face is how to limit increases in generation and emissions of CO_2 outside the RGGI region.

RPS and Other Policies to Promote Renewables

The renewable portfolio standard is another policy tool that has become increasingly popular with states and that could help to reduce emissions. As discussed above, the emissions-reducing effects of an RPS are not as large as some had previously predicted. However, the CO_2 emissions reductions from an RPS on the order of 10% will more than offset the CO_2 emissions increases predicted by Palmer et al. (2002) to result from a transition to more widespread restructuring.[25] Although an RPS is not a national policy, the renewable energy production credit was recently renewed and expanded to include more sources of generation; it will be in effect through 2005. Should the credit be continued indefinitely, this policy has emissions-reducing effects similar to the 10% RPS and thus could also serve to more than offset the emissions increases likely from electricity restructuring found by Palmer et al. (2002).[26]

Gas Prices

The effect of high gas prices on emissions from the electricity sector present a mixed bag. On the one hand, higher natural gas prices make coal-fired generation more attractive relative to natural gas units, and as a result coal units tend to be dispatched more than natural gas, which tends to raise emissions. At the same time, renewables generation also increases and has an emissions-reducing effect. Also, higher gas prices tend to lead to higher electricity prices, which can have a dampening effect on electricity demand.

The net effect on emissions will depend on the size of the gas price increase, among other things. In one analysis, Palmer and Burtraw (2005) find that natural gas prices that are 15% greater than the long-run levels predicted in a reference case (from the Annual Energy Outlook 2003 (EIA 2003a) result in a 3% increase in electricity price and a 1% reduction in electricity demand. This price increase also results in a 10% reduction in gas generation with almost offsetting increases in coal and renewables generation. In their analysis, the net effect on CO_2 emissions from the electricity sector was zero.

[25] Palmer and Burtraw (2004), Table 4, column 3.

[26] Palmer and Burtraw (2004), Table 4, column 6.

Other Things Matter More to Consumers Than Competition

Although the effects of electricity restructuring on retail prices have been mixed and the ultimate result of markets' setting retail prices has not yet been achieved in many states that have gone through restructuring, consumer savings have generally not met with expectations. Initial price declines of 10% or more have not generally been sustainable over time as fuel costs have risen and markets have been thin. Given that most of the high-cost states have gone through restructuring, additional savings from restructuring in lower-cost states are likely to be even smaller than the savings experienced to date, with simulation analysis suggesting price reductions on the order of 2% from making retail competition nationwide (Palmer et al. 2002). These small effects pale in comparison with the potential effects of other policy initiatives or changes in fuel prices on electricity prices and consumer welfare. Two factors in particular merit further discussion: allocation of CO_2 emissions allowances and changes in natural gas prices.

The spread of retail electricity restructuring beyond states that haven't already restructured seems unlikely, but the prospects for some sort of binding CO_2 constraint on the electricity sector may be a bit higher. Regional initiatives such as RGGI in the Northeast and ongoing discussions among the West Coast governors about binding climate policies for their states suggest that regional constraints are very likely. These initiatives seek to provide model systems that could be the foundation for a national CO_2 policy.

One important design question associated with any cap-and-trade program is the question of how to initially allocate the emissions allowances. Three basic approaches have been suggested (Burtraw et al. 2001b). One is to allocate allowances to firms at no cost based on some historical measure of performance, either generation or emissions, and to use that unchanging formula indefinitely. This approach was used to allocate SO_2 allowances under Title IV. A second approach is to allocate allowances to firms at no cost based on recent measures of performance, such as generation. This approach has been used in some states to allocate NO_x allowances under the NO_x SIP Call program. A third approach is to auction emissions allowances to the highest bidder. This last approach has typically not been used, although in Virginia a small portion of the NO_x SIP Call allowances are being sold in an auction.[27]

[27] Burtraw et al. 2005 review allocation approaches under the Ozone Transport Region NO_x budget trading program, which preceded the NO_x SIP Call. A small portion of the Title IV SO_2 allowances are also sold in an auction each year, and the revenues from those sales are distributed back to the electricity-generating companies to which those allowances were initially allocated.

When allowances are given away for free, the approach used in most programs, the impact on electricity prices varies importantly between regulated states and competitive states. In competitive states, generation prices are set based on the marginal cost of the marginal unit supplying electricity at a given time; if that unit must surrender emissions allowances to generate, then the competitive price will reflect the opportunity cost of using those allowances. In regulated states, prices are set based on average cost, and allowances that are given for free to regulated firms are treated as having zero cost for rate-setting purposes. This difference can have a big effect on electricity prices. For instance, the analysis by EIA of the McCain-Lieberman economywide carbon cap proposal is sensitive to the assumption about cost-recovery rules in regulated regions. The analysis assumes ratepayers receive 90% of the benefits of freely distributed allowances and company shareholders receive 10%. However, in competitive regions, when a fossil-fired unit is on the margin and sets the price in the region, the opportunity cost of emissions allowances is fully reflected in electricity price (U.S. EIA 2003b, 133).[28] This difference in prices dwarfs the magnitude of the savings realized so far from restructuring or expected from further restructuring. The difference in electricity price between regulated and unregulated regions disappears under an auction because firms are required to purchase emissions allowances, and thus the opportunity cost of those allowances is reflected in electricity prices.

The relationship between electricity prices and natural gas prices becomes even more important when the electricity price is set in competitive markets. When the price of natural gas increases, electricity prices will be affected in both regulated and unregulated states but in different ways. In regulated states, the increase in gas costs will raise the cost of using natural gas generators, and these higher costs, to a first approximation, will affect electricity generation prices in direct proportion to the share of natural gas generation in the mix.[29] However, in competitive markets, the increase in generation costs with natural gas will increase the market price of electricity whenever gas generators are on the margin, and the market price will go to all kWh sold at that time in the market, whether generated using natural gas or some other fuel. This means that during peak periods, when gas-fired units are typically on the margin, the impact of a

[28] Moreover, the social cost from using an auction can be one-third that of using historical allocation to distribute emissions allowances in a nationwide CO_2 trading program (Burtraw et al. 2001c).

[29] This simple statement ignores any reduction in the share of gas generation that might result as utilities shift away from gas toward greater use of coal. It also ignores any increase in the price of coal that could result from greater demand for this fuel.

gas price increase on electricity price is much greater under competition than it would be under regulation.

6. Conclusions

Electricity restructuring has had both predictable and unanticipated effects on the mix of fuels and technologies used to generate electricity. Despite the dearth of new coal-fired facilities brought on line in the 1990s, capacity factors at coal-fired plants have increased substantially since 1996, helping to maintain coal's roughly 50% share of total generation. Investments in new gas-fired facilities have reached unprecedented levels in the past couple of years, exceeding expectations that many had for new investment postrestructuring and exceeding demand for output from those new facilities. No additional nuclear plants have gone off-line permanently since 1998, and generation at existing nuclear plants has grown significantly over the past 10 years. The availability of green power offerings, particularly from traditional utilities, has increased substantially, but their share of the market has remained quite low. Instead, renewables are being promoted through other means, such as renewable portfolio standards, which are more prevalent in states that have undergone restructuring than in those that have not.

The contribution of restructuring to those many changes in electricity supply is difficult to discern from aggregate time series data, particularly given the concurrent changes in environmental regulations and input fuel prices. Most notably, increases in natural gas prices have played a role in the growth in coal-fired generation. To the extent that these price increases are driven by supply-side effects, such as lower productivity at existing and new gas wells, and not by demand shifts, this phenomenon is largely separate from restructuring itself.

It is even more challenging to tease out an estimate of the effect of restructuring on electricity sector emissions. Ex ante analyses suggested that effects of restructuring on emissions of NO_x and CO_2 were likely to be small, while no changes in emissions of SO_2 emissions were expected because the role of the aggregate emissions cap. Research also shows that the imposition of the SIP Call cap-and-trade program would substantially limit restructuring-related increases in NO_x emissions. Restructuring-related increases in aggregate NO_x emissions in the East would be totally avoided by an annual NO_x cap-and-trade program, such as that contained in EPA's CAIR rule. A four-pollutant bill that caps emissions of NO_x, CO_2, SO_2, and mercury from the electricity sector using a cap-and-trade approach would eliminate all restructuring-related increases in aggregate emissions of these pollutants nationwide. An economywide cap on carbon emissions would also mitigate increases in that pollutant as well.

The main environmental consequence of restructuring may be more related to its effect on the future of new environmental policies than its effect on emissions directly. Emissions cap-and-trade programs with freely distributed allowances can have dramatically different effects on electricity prices between states where electricity markets are regulated and those where markets have been restructured. In restructured states, prices reflect the full opportunity cost of emissions allowances used by the marginal firm, whereas in regulated states, the cost of freely allocated allowances is not reflected in electricity price. This difference can be very substantial for CO_2 allowances and may create a geographic divide in willingness to accept these regulations, and could have serious implications for the ability of the regulation to provide incentives to conserve electricity in regulated states.

Finally, we note that the most important factor affecting electricity prices over the past few years has not been the direct result of public policy. Rather, the wildcard affecting electricity price has been the price of natural gas, and natural gas price has also been a very important factor in affecting the choice of technology for electricity generation. If natural gas prices had remained relatively low, as they were in the 1990s when the movement toward restructuring took hold, the environmental consequences of restructuring might be more easily discerned. The massive investment in natural gas–fired technology that occurred at the end of that decade, coupled with lower natural gas prices, would have led to an expanded role for gas at the expense of coal-fired generation, with associated reductions in emissions of pollutants not under emissions caps. The unforeseen magnitude of investment in natural gas generation set the stage for an accelerated transition to the long-term consequences of restructuring—a large role for gas with its associated environmental advantages. But alas, the rise in gas prices early in this decade preserved the role for coal. On balance, the environmental impact of restructuring seems to be small, though probably ultimately positive, given that the one most tangible consequence of restructuring is the large investment in natural gas facilities that are part of the technology mix we have today.

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Tables

Table 1. Nuclear Reactors Shut Down Since 1992

Reactor Unit Name	*Net Capacity (Mwe)*	*Location*	*Initial Commercial Operation*	*Date of Shutdown*
Big Rock Point	67	Michigan	March 1963	August 1997
Haddam Neck	560	Connecticut	January 1968	December 1996
Maine Yankee	860	Maine	December 1972	August 1997
Millstone - 1	641	Connecticut	March 1971	July 1998
San Onofre- 1	436	California	January 1968	November 1992
Trojan	1095	Oregon	May 1976	November 1992
Zion 1	1040	Illinois	December 1973	January 1998
Zion 2	1040	Illinois	December 1974	January 1998

Source: U.S. EIA. http://eia.doe.gov/cneaf/nuclear/page/nuc_reactors/shutdown.html (accessed February 11, 2005).

Table 2. Annual Emissions from Electricity Generators for Selected Years, 1992–2003*

Emission	*1992*	*1996*	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*
CO_2 (million metric tons)	1,951	2,155	2,223	2,313	2,327	2,429	2,380	2,398	2,409
SO_2 (thousand short tons)	16,534	14,199	14,876	13,760	13,690	12,427	12,063	11,567	11,653
NO_x (thousand short tons)	8,501	6,909	6,956	6,859	6,305	5,918	5,550	5,282	4,836

*The totals include emissions from all useful heat input at combined heat-and-power plants. Source: EIA Electric Power Annual 2004, Table 5.1 (emissions for SO_2 and NO_x converted to short tons).

Table 3. Selected States with Multipollutant Rules Affecting the Electricity Sector

State	*Pollutants*	*Form of Regulation*	*Effective Dates*
Connecticut	SO_2, NO_x	Emissions rate standards.	2003 for SO_2. 2002–2003 for NO_x.
Massachusetts	SO_2, NO_x, CO_2, Hg	Emissions rate standards for SO_2, NO_x, and CO_2. Reduction from baseline emissions levels for Hg.	Phased in 2004–2006 for SO_2 and NO_x. Phased in 2005–2007 for CO_2, 2008 for Hg.
Missouri	NO_x	Tradable performance standard for summer emissions only.	2004.
New Hampshire	NO_x, SO_2, CO_2	Emissions caps.	2006.
New York	NO_x, SO_2	Emissions caps.	2005 for NO_x. Phased in 2005–2008 for SO_2.
North Carolina	NO_x, SO_2	Company-specific emissions caps.	Phased in 2007–2009 for NO_x. Phased in 2009–2013 for SO_2.
Texas	NO_x, SO_2	Regional emissions caps.	2003.
Wisconsin	NO_x, SO_2, Hg	Emissions rate standards.	Phased in 2007–2012 for SO_2 and NO_x. Phased in by 2012 for Hg.

Figures

Figure 1. Capacity Factors for Coal-Fired Generators and Natural Gas Prices

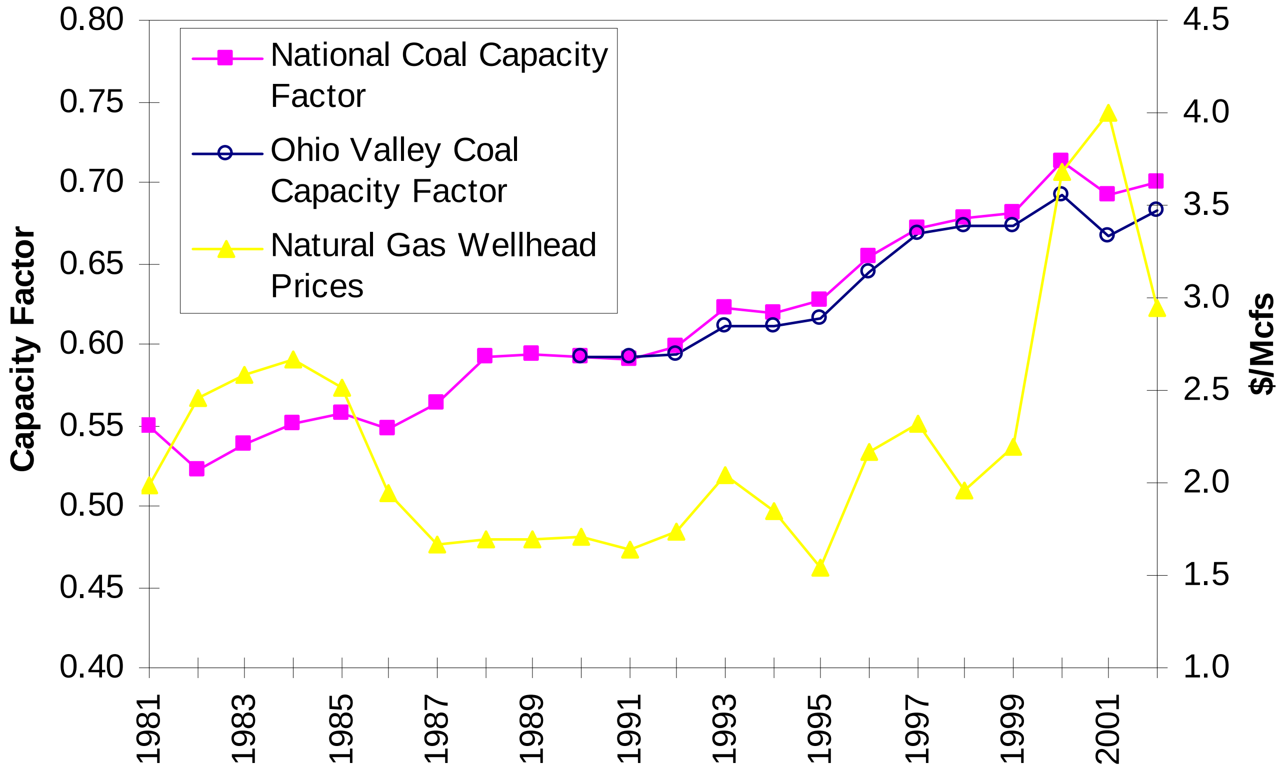
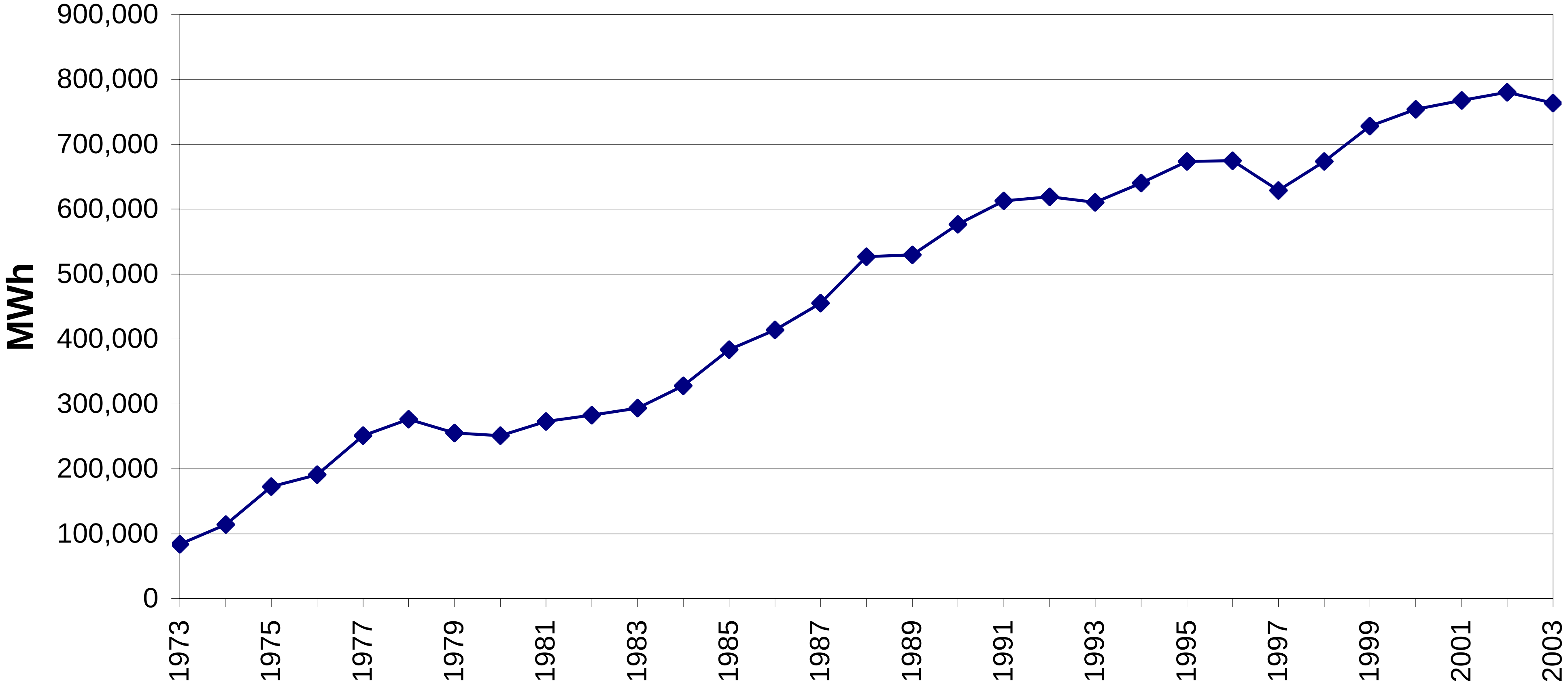


Figure 2. Nuclear Generation



Source: Energy Information Administration, Monthly Energy Review.

Figure 3. Nuclear Capacity Factor

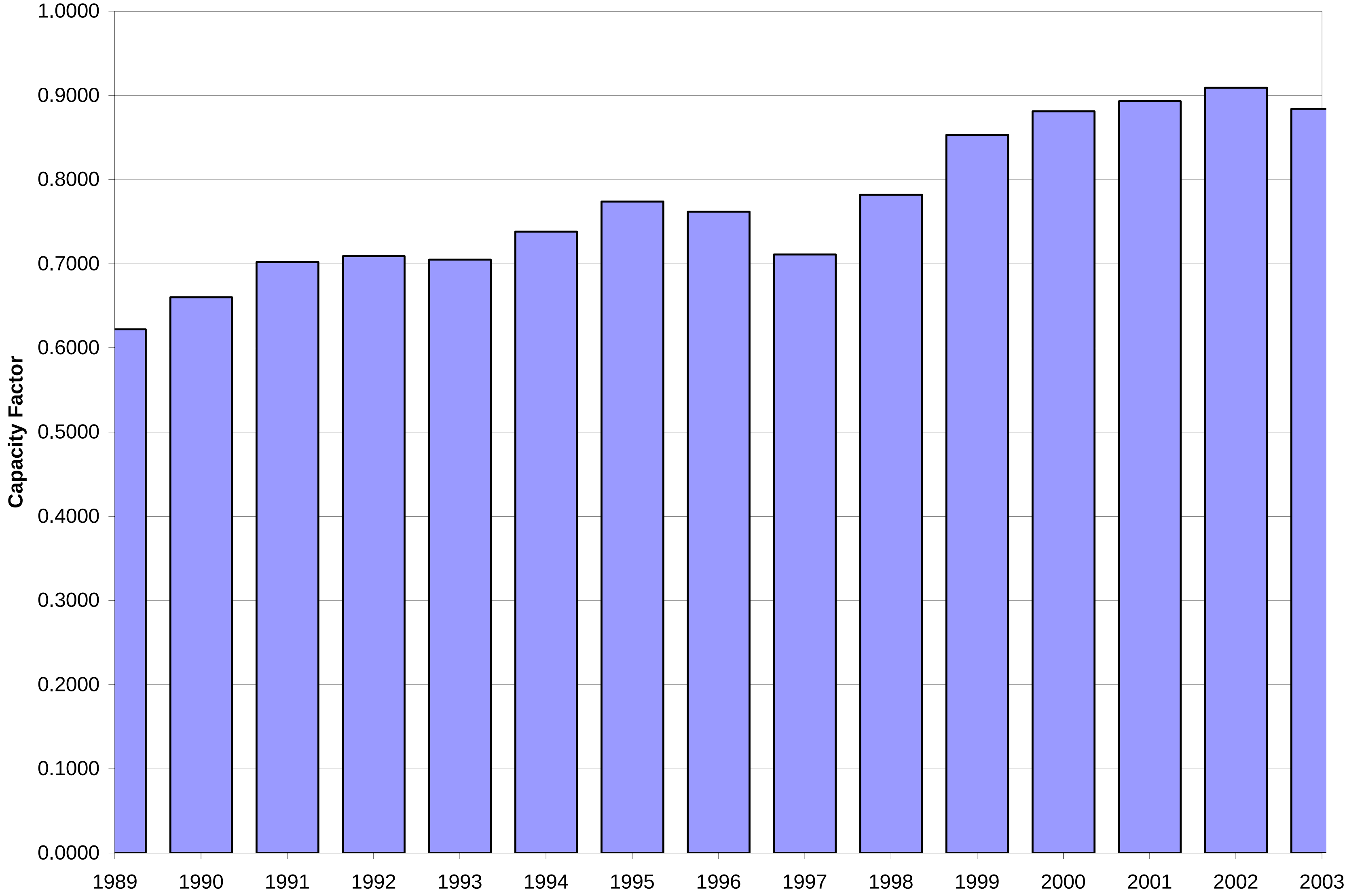


Figure 4. Capacity Additions by Year and Fuel

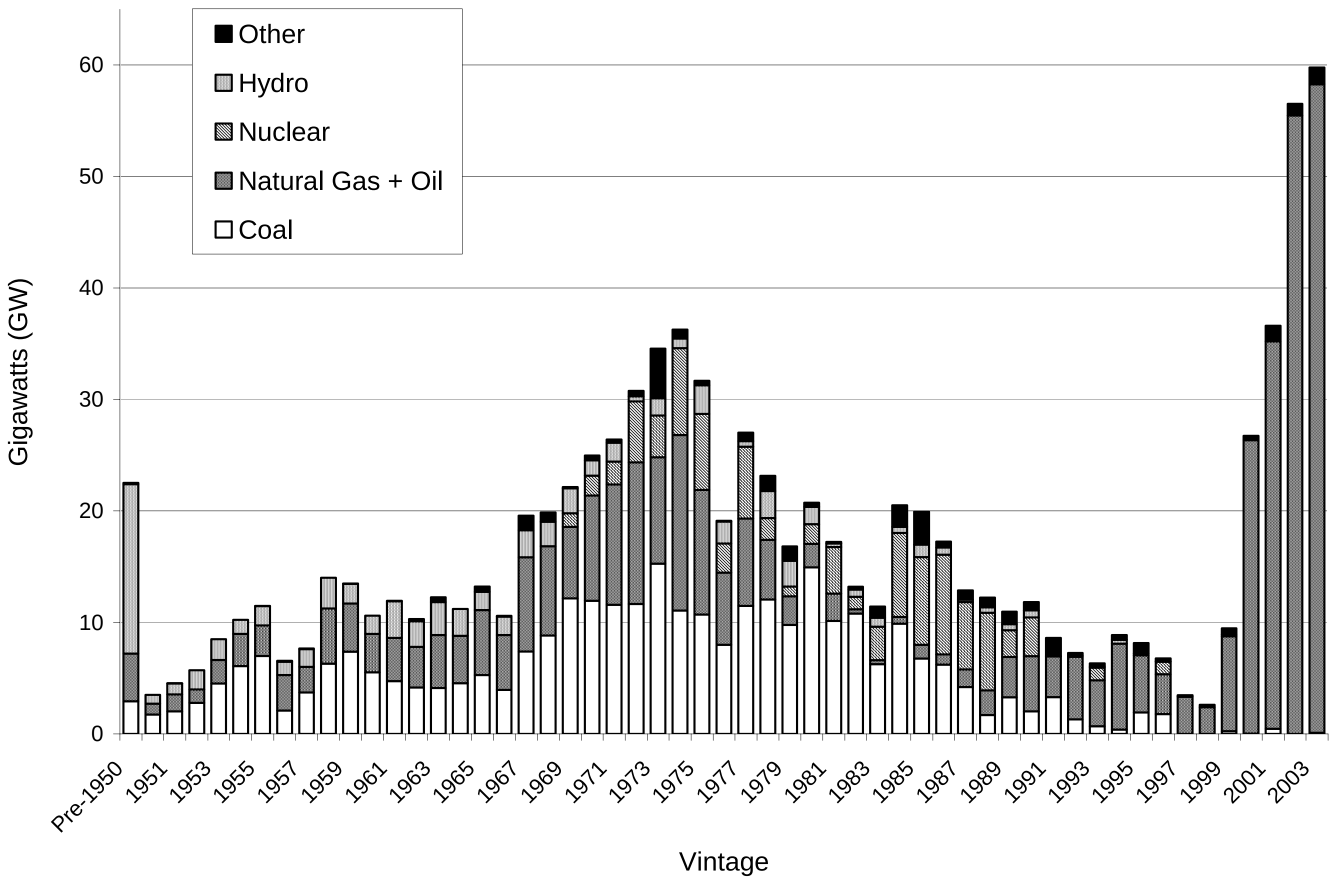


Figure 5. Average Annual Retail Electricity Prices for Residential Customers in Selected States and Nationwide

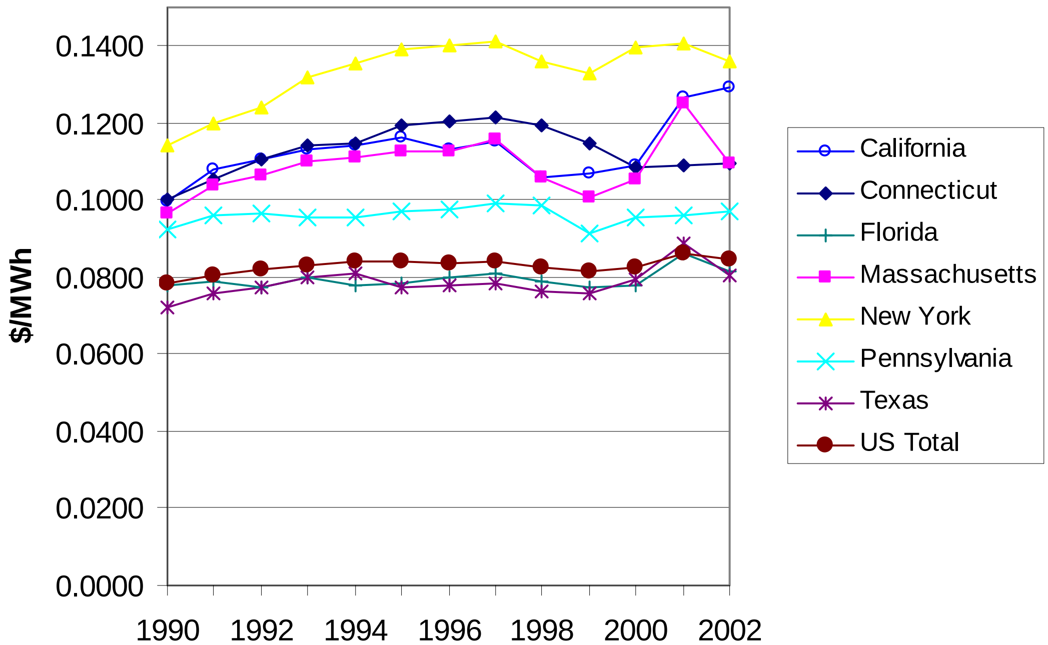


Figure 6. Average Annual Retail Electricity Prices for Commercial Customers in Selected States and Nationwide

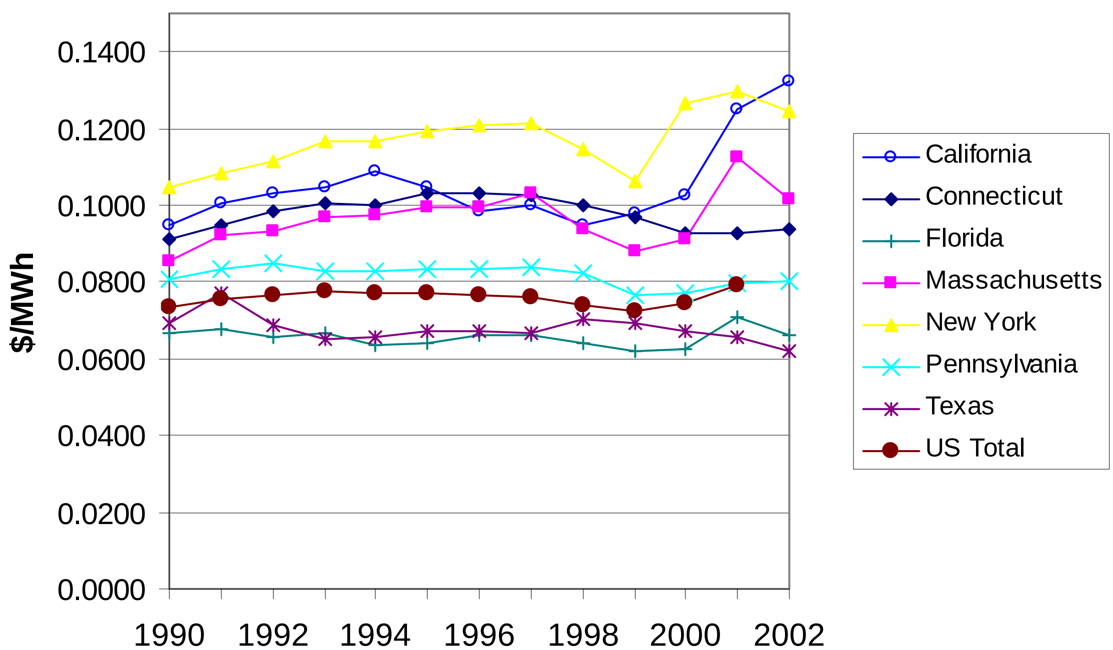


Figure 7. Average Annual Retail Electricity Prices for Industrial Customers in Selected States and Nationwide

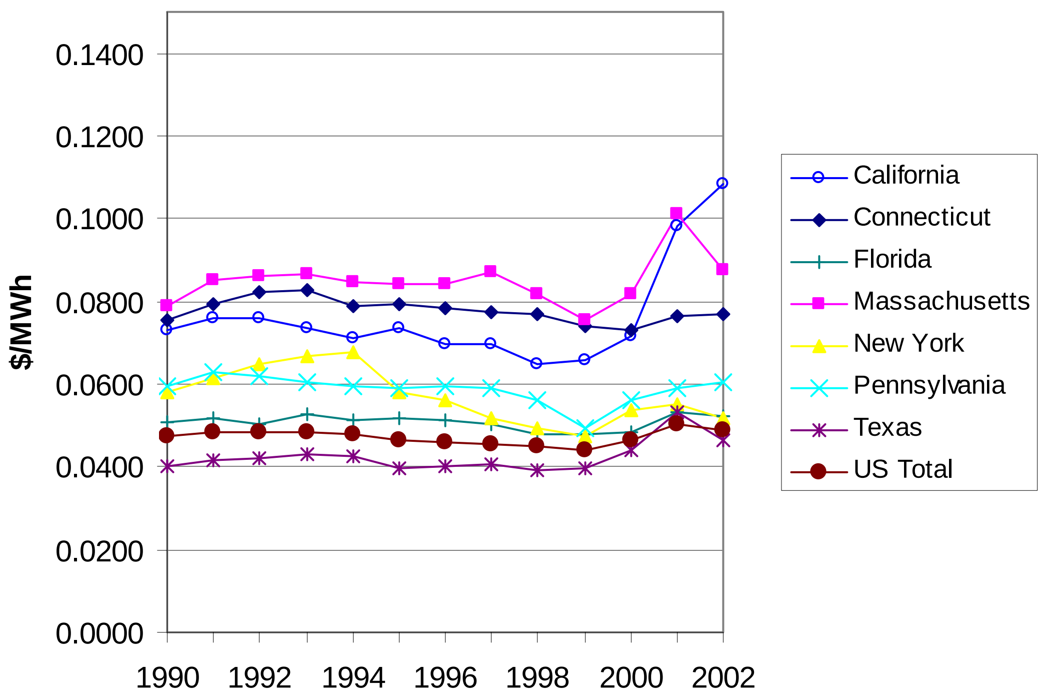


Figure 8. Average Annual Retail Electricity Prices for All Customers in Selected States and Nationwide