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A Retrospective Review of FERC's Environmental Impact Statement on Open Transmission Access

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Executive Summary

Over the last decade there has been an ongoing, extensive discussion of the environmental implications of increased competition in the electricity industry. As part of that discussion, this study examines the Federal Energy Regulatory Commission (FERC) analysis of "Order 888," a proposal to increase competition in US wholesale electricity markets by promoting open access to transmission lines.

FERC's final environmental impact statement (FEIS) for Order 888 was issued in 1996, including detailed forecasts of the expected environmental effects of increased competition. Starting from a base year of actual data for 1993, the FEIS projected several scenarios for electricity industry activity and associated air emissions for the years 2000, 2005, and 2010. The FEIS found that competition would slightly increase air emissions under some scenarios, and would slightly decrease emissions under other scenarios. The overall environmental effects of competition appeared to be small, and FERC projected that they were likely to be less important than other benefits of increased competition.

We now have the opportunity to compare the FEIS projections for 2000 with actual experience up to and including that year. Our objective is not to critique FERC's methodology with the benefit of hindsight, but to identify lessons that can be learned about the expected and unexpected environmental implications of increased competition in the US electricity industry.

FERC's Methods and Findings

FERC's modeling effort included two base cases with no assumed increase in competition, three principal scenarios modeling effects of competition, and at least eight sensitivity analyses. The two base cases differed in fuel price assumptions, one assuming that natural gas would become significantly more expensive relative to coal (which we refer to as the "base case favors coal"), and the other assuming a continuation of the relative fuel prices of 1986-96 (the "base case favors gas").

Corresponding to the two base cases were scenarios modeling the effects of increased competition and using the same price assumptions, the Competition-Favors-Coal and Competition-Favors-Gas Scenarios. The third option, the Low-Response Scenario, is quite similar to Competition-Favors-Coal in its projections. The sensitivity analyses were added in response to criticisms of the FEIS, several of them based on other agencies' assumptions, which FERC viewed as unrealistic.

The principal environmental results of the FERC analysis were as follows:

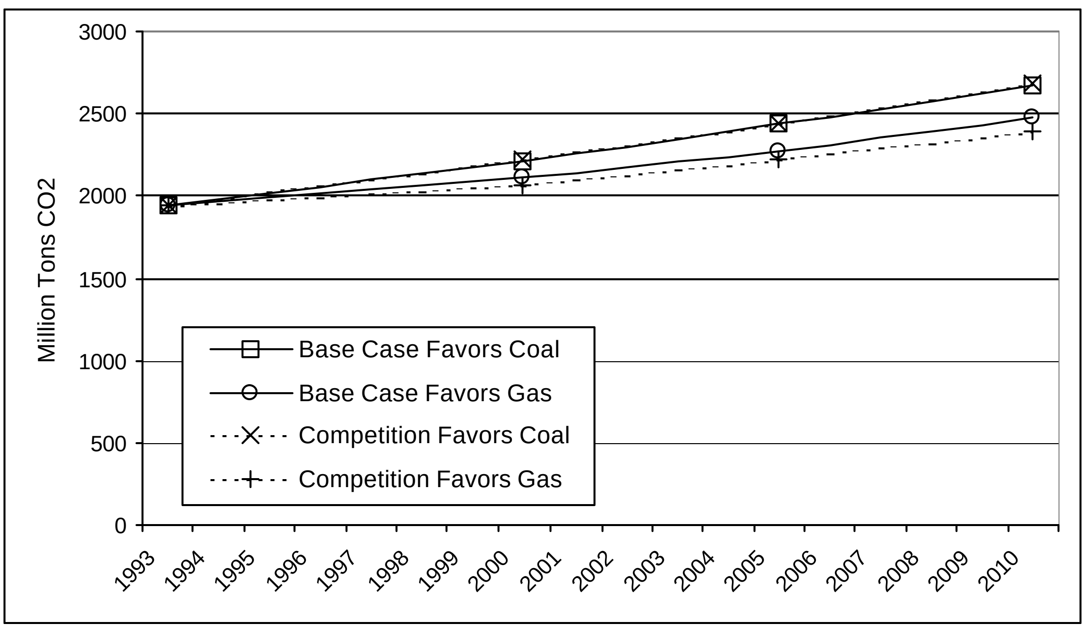
- National nitrogen oxide (NO_X) emissions from power plants are projected to be higher than in the base case by less than 2 percent under both the Competition-Favors Coal and Low-Response scenarios. National NO_X emissions are projected to be lower by three percent in the Competition-Favors-Gas Scenario.
- National carbon dioxide (CO_2) emissions in 2010 are projected to be higher than in the base case by less than one percent in the Competition-Favors-Coal and

Low-Response scenarios, and to be lower by three percent in the Competition-Favors-Gas Scenario.

- National sulfur dioxide (SO_2) emissions are projected to decrease throughout the study period in accordance with the nationwide cap on SO_2 mandated by Title IV of the Clean Air Act of 1990. The proposed rule will not affect the timeframe for national SO_2 emissions reductions.
- National emissions of mercury are projected to increase by two percent in the Competition-Favors-Coal Scenario, to remain constant in the Low Response Scenario, and to be lower by one to three percent in the Competition-Favors-Gas Scenario.
- Impacts on water and land use are found to be small in all scenarios.

As indicated in Figure ES-1, FERC's projections of CO_2 emissions depend almost entirely on the assumptions regarding relative coal and gas prices. This point applies to NO_X emissions as well. FERC's analysis concludes that competition will have very small environmental impacts relative to fuel price dynamics.

Figure ES.1 FEIS Projection of National CO_2 Emissions



One thing that is clear with the benefit of hindsight is the pattern of relative fuel prices. Gas prices have turned out to be high, while coal prices have remained relatively low. Therefore, among all the FERC scenarios and sensitivity analyses, the fuel prices in the Competition-Favors-Coal Scenario are generally the closest to actual experience through 2000. For this reason, we interpret the base case favoring coal, and Competition-Favors-Coal, as the FERC forecasts that are most relevant to consider in light of recent experience. Consequently, most of our report focuses on these scenarios.

As described above, the Competition-Favors-Coal Scenario leads to an increase in NO_X and CO_2 emissions relative to the corresponding base case. This is important because it means that recent experience indicates that electricity competition is likely to increase air emissions from power plants. The several scenarios that FERC analyzed where air emissions were reduced slightly have turned out to be irrelevant.

Comparison of FERC's Emissions Projections With Recent Experience

In general, the FEIS projections for air pollution in 2000 – in both the base cases and competition scenarios – were lower than actual experience. For the US as a whole, the FEIS projection for 2000 NO_x emissions was 5.4 percent lower than actual for the base case (favoring coal), and 4.3 percent lower than actual for Competition-Favors-Coal. Projections of national CO_2 emissions for 2000 were lower than actual by 8.5 percent in the base case, and by 7.9 percent in Competition-Favors-Coal.

In addition to national data, we examine projections for four regions in the eastern US: New England, the Mid-Atlantic, the South Atlantic, and the East North Central (the northeastern Midwest). Much of the controversy over the effects of increased transmission access focused on potential increases in air emissions in these regions. In particular, some analysts argued that overall emissions might increase if coal-fired plants in the South Atlantic and East North Central regions increased their exports of power to New England and the Mid-Atlantic, displacing new, lower-emission generators in the Northeast.

In short, as of 2000, Competition-Favors-Coal underestimated actual national emissions of both pollutants, by a wider margin for CO_2 than for NOx. On a regional basis the scenario underestimated emissions in New England and East North Central, overestimated NOx for the Mid-Atlantic and the South Atlantic, and came quite close to actual figures for CO_2 for the latter two regions.

While we did not analyze mercury emissions in 2000, it is likely that the FEIS projections underestimated these emissions as well because the FEIS underestimated coal generation, which is the major source of mercury emissions from electricity generation.

Electricity Generation and Consumption

The most important factor accounting for the gap between actual and projected emissions was the growth in generation. Nationally, generation grew faster over the period 1995 through 2000 than FERC had predicted; the projection for generation in 2000 under Competition-Favors-Coal was 173 billion kWh, or 4.6 percent, below the actual figure. FERC underestimated generation in all three major fuel categories, coal, nuclear, and oil/gas-fired power plants. By far the largest difference was in nuclear generation, accounting for 122 billion kWh, the majority of the total underestimate. Most of the rest of the gap was in oil and gas; the error in projecting coal-fired generation was the smallest.

Regionally, New England's actual generation in 2000 was quite close to the scenario estimate. Three of the region's nuclear units were retired during the 1990s, so more generation was fossil-fueled and less was nuclear than FERC had projected – a fact that likely explains the underestimate of New England air emissions, noted above. New England also had increasing power imports during the 1990s.

Generation in the Mid-Atlantic was also quite close to the scenario estimate for 2000, with roughly the predicted mix of fuel types. This likely accounts for the fairly accurate projection of CO_2 emissions; unexpected rapid introduction of NOx controls may have accounted for FERC's overestimate of NOx emissions. The Mid-Atlantic region consistently exports power, of an amount roughly equal to New England's imports (coincidentally).

The South Atlantic had rapid growth of generation in the 1990s, but the Competition-Favors-Coal projection of generation was very close to the actual figure for 2000. As in the Mid-Atlantic, this is consistent with the relatively accurate CO_2 projection, while introduction of NOx controls may explain the overestimate of NOx emissions. Despite rapid growth of generation, there was no surge of power exports; in fact, the South Atlantic is a net importer of power. All of its increase in generation was required to meet the region's own load growth.

In the East North Central region, the Competition-Favors-Coal projection underestimated generation in 2000 by two percent. Here, as in all the regions we examined except New England, there was a significant expansion in coal-fired generation. Since emissions were underestimated by more than two percent, generation must have become more emissions-intensive, on average, than FERC projected. The East North Central region was a net importer of power in the 1990s, with a gradually increasing level of imports. As in the South Atlantic, its increase in generation was required to meet local load growth.

Therefore, it appears that predictions about low-cost coal generation in the Midwest and Southeast being increased to export power to other regions have not been confirmed by actual experience. Instead, these regions have increased coal generation in order to meet unexpectedly high electricity load growth within the local region. Although increased exports did not materialize by 2000, the main concern of an increase in emissions in upwind regions did occur – even if not for the reasons originally feared.

FERC's Modeling Assumptions

We have seen that FERC's most relevant (and most accurate) scenario, evaluated against actual experience for 2000, underestimated CO_2 emissions by 7.9 percent, and generation by 4.6 percent. The fact that CO_2 was underestimated by more than generation implies that, on average, electricity production became slightly more carbon-intensive than FERC projected.

There are two sets of FERC assumptions that affect FEIS projections of emissions (beyond generation and fuel prices, the dominant influences which we have already discussed). First, there are FERC assumptions used to model the likely impacts of Order 888 on the electricity industry. Second, there are other assumptions that were common to all base cases and competition scenarios.

In the first set of assumptions, FERC assumed that reduced barriers to transmission were equivalent to a lowered usage price for the transmission grid. This approach is hard to test against the evidence but appears reasonable to us, and probably does not bias the forecasts. Other FERC assumptions about the effects of competition – the anticipated decline in planning reserve margins, increase in fossil plant availability, and changes in fossil plant heat rates – have turned out to be slightly inaccurate. All of these inaccuracies should have biased the projections toward overestimating emissions, the opposite of the observed result.

The second set of assumptions, those that were common to all FERC base cases and scenarios, include several factors with major impacts on the projections. Generation was underestimated, as noted above. Coal plant lifetimes were also underestimated, a factor that is of little importance by 2000 but will affect later years of the projections. Nuclear capacity factors were substantially underestimated: FERC assumed an average capacity factor of 74 percent for the nation's nuclear plants throughout the study period, while the actual figure in 2000 was an impressive 90 percent. FERC's low estimate of nuclear capacity factors leads to an overestimate of fossil generation requirements, and thus should also tend to cause an overestimate of air emissions.

We are unable to quantify and untangle the contribution of each of these factors to the FERC projections. However, there are useful lessons to be learned from the FERC analysis that can guide future efforts. In particular, FERC did not assess the potential for increased competition to result in increased electricity sales, which would naturally result in increased air emissions. Similarly, FERC did not account for the potential for increased load growth as a result of reduced utility demand-side management (DSM) efforts, which would also result in increased air emissions. In addition, FERC did not assess the potential for nuclear capacity factors to improve with increased competition, as utilities sell their generating units and place them in the hands of a few companies with substantial nuclear expertise. Recent experience demonstrates that these factors should be considered in future analyses of competitive electricity markets.

Some of the modeling assumptions may become important as the era of competition continues, but do not appear to have affected outcomes as of 2000. It is not yet clear whether competition is responsible for large increases in generation, but it could be in the future. Likewise, plant life extension for coal and other plants could be an important result of competition in the future, but has not yet had a major impact. These factors should be carefully considered in any further investigation of the environmental effects of competition.

General Conclusions

- Natural gas prices have been relatively high and coal prices have remained relatively low since the FEIS was prepared. Consequently, FERC's Competition-Favors-Coal Scenario most accurately represents recent industry experience, as well as the most likely future. This Scenario indicates that increased competition at this time is more likely to lead to increased air emissions than decreased emissions – absent additional actions to reduce the environmental impacts of electricity generation and consumption.

- FERC's projections of national NO_X and CO_2 emissions in 2000 were lower than actual experience. In the Competition-Favors-Coal Scenario, FERC's forecast of NO_X emissions was roughly four percent lower than actual experience, and its forecast of CO_2 emissions was roughly eight percent lower. While we did not analyze mercury emissions in 2000, it is likely that the FEIS projections underestimated these emissions as well because the FEIS underestimated coal generation.

- FERC's projection of national electricity demand through 2000 was lower than actual experience, by 4.6 percent. This is the dominant factor explaining why FERC's projections of NO_X and CO_2 emissions were lower than actual experience. A more thorough investigation of the environmental impacts of competition should assess the potential for competition to increase electricity demand, and the extent to which increased demand would lead to increased air emissions. Such an assessment should consider the effect that competition has on utility DSM programs, and their impact on electricity demand.

- FERC assumed that a number of electricity industry factors would remain unaffected by competition. It is quite likely that some of these factors – in particular electricity demand, nuclear generation, and nuclear and coal plant lifetimes – *would* be affected by increased competition. In other words, FERC's assumptions regarding the likely changes due to Order 888 were too narrowly defined. Future analyses of the environmental impacts of electricity competition should consider these factors in more depth.

- Of those electricity industry factors that were assumed to be affected by competition, FERC's assumptions under the Competition-Favors-Coal Scenario turned out to be fairly close to actual experience in recent years. The slight deviations between FERC's assumptions and actual experience are likely to lead to increased air emissions in most cases.

- Coal-fired power plants in the Midwest and South do not appear to have increased generation in order to export power into other regions in response to Order 888. While coal generation has increased considerably in the Midwest and South Atlantic regions, this increased generation was needed to meet load growth within each region. Nonetheless, while electricity exports did not increase, air pollution did, which was the chief concern of those expressing fears of greater exports from regions dominated by relatively less-controlled coal power plants.

- The FERC underestimate of CO_2 emissions was greater than the underestimate of generation growth, indicating a more carbon-intensive generation mix than originally projected. This has important implications for climate change policies.

1. Introduction

In 1995 the Federal Energy Regulatory Commission (FERC) opened a rulemaking procedure to increase competition in US wholesale electricity markets through policies promoting non-discriminatory, open access to transmission lines. (FERC 1995) In 1996 FERC issued a final environmental impact statement (FEIS) of the proposed rule, in accordance with the requirements of the National Energy Policy Act. (FERC 4/1996)

The FEIS projected that the proposed rule would have only a small impact on air emissions over the following fifteen years. Under some scenarios the proposed rule was found to reduce air emissions slightly, while under other scenarios the proposed rule was found to increase air emissions slightly. The FEIS found other factors in the electricity industry would have a much larger impact on the environment than the open access rulemaking. The FEIS concluded that the benefits of the proposed rule would outweigh the potential environmental costs, and that there was no need to undertake environmental mitigation measures beyond those already underway through other agencies and forums.[1]

The FEIS was based on projections of the US electricity industry and associated air emissions for the years 2000, 2005, and 2010. We now have the opportunity to compare the FEIS projections for 2000 with actual experience in the electricity industry through 2000. Such a comparison will shed light on FERC's projections and conclusions.

The objective of this study is not to review and critique FERC's FEIS methodology and conclusions with the benefit of 20/20 hindsight. Instead, the objective of this study is to identify lessons that can be learned from FERC's analysis and recent experience, in order to inform the on-going debate about the environmental implications of increased competition in an integrated North American electricity market.

This study begins with a summary of the FEIS methodology, findings and conclusions. We then compare the FEIS projections of nitrogen oxide (NO_X) and carbon dioxide (CO_2) emissions for 2000 with actual emissions in 2000. We then investigate the reasons for any differences between actual and projected emissions, by evaluating US and regional electricity generation patterns, and by reviewing the various modeling assumptions that FERC used in making the projections. Finally, we summarize our findings and general conclusions.

[1] FERC's proposed rule was eventually implemented through Order 888. (FERC 5/1996) For the remainder of this report, we refer to the open access rulemaking as Order 888, even though that order did not yet exist at the time the FEIS was released.

2. The FERC FEIS and Its Findings

2.1 The FERC FEIS Methodology

Base Cases

FERC assessed the environmental impacts of Order 888 using the Coal and Electric Utilities Model (CEUM) to model electricity generation and emissions under different assumptions about the future. The first step in this modeling effort was the establishment of base cases – future scenarios in which it was assumed that Order 888 is not implemented. The base cases focused on what FERC believed to be the key variable, separate from Order 888, that would determine electric industry emissions during the modeled period: the relative prices of coal and natural gas. Two bases were developed:

- *The High-Price-Differential Base Case.* Natural gas is assumed to become substantially more expensive compared with coal than it was in the recent past. Gas prices rise significantly and coal prices fall slightly. For reasons that will become clear later in this report, we will sometimes refer to this scenario as the "base case favors coal."

- *The Constant-Price-Differential Base Case.* Natural gas is assumed to maintain essentially the same price relative to coal that existed from 1986 to 1996. Both coal and gas prices fall slightly over the modeled period. We will sometimes refer to this as the "base case favors gas."

Having established the fuel price parameters of these two base cases (as well as other assumptions about the future of the industry absent Order 888) FERC ran the CEUM model for the two cases through the year 2010. The results of these model runs established what FERC believed to be the high and low limits of possible air emissions in a future without implementation of Order 888. These emissions boundaries are driven by the relative prices of coal and gas. When natural gas is less expensive, air emissions are lower. When natural gas is more expensive, air emissions are higher.

Competition Scenarios

To assess the potential environmental impact of Order 888, FERC developed three "competition scenarios," in which they assumed various changes to the industry resulted from implementing Order 888. These three scenarios assume three different general outcomes. The first scenario assumes that Order 888 strongly pushes the industry toward competition and that it does this in a way that tends to favor coal-fired generation over gas-fired generation. The second also assumes that Order 888 has a strong effect but that this effect tends to favor gas over coal. The third assumes that Order 888 has little effect on the rate at which wholesale electric markets become more competitive.

- *The Competition-Favors-Coal Scenario.* Order 888 is assumed to result in efficiency gains in the electric industry generally (e.g., lower reserve margins) as well as dynamics that favor coal (e.g., better availability and heat rates for existing plants, largely coal-fired). To reflect a future that is generally favorable to coal, FERC used the same fuel price assumptions as in the High-Price-Differential Base Case.

- *The Competition-Favors Gas Scenario.* Order 888 is assumed to result in efficiency gains in the electric industry generally (e.g., lower reserve margins) as well as dynamics that favor gas (e.g., lower heat rates for natural gas plants). To reflect a future that is generally favorable to gas, FERC used the same fuel price assumptions as in the Constant-Price-Differential Base Case.
- *The Low-Response Scenario.* Order 888 is assumed to lead to no efficiency gains as a result of increased competition in the industry. For this scenario, FERC used the same fuel price assumptions as in the High-Price-Differential Base Case, because these prices are likely to result in the greatest environmental impacts.

According to the FEIS, these alternative scenarios were designed to provide a range of potential impacts that could results from Order 888.

Sensitivities

Before completing the FEIS, FERC released a Draft EIS (DEIS) and asked for public comments. In response to the comments received FERC prepared three sensitivity analyses to investigate how their results would change if key assumptions were different. FERC considered the following sensitivities:

- *Two "Frozen Efficiency" Reference Cases*. There is no further open access of any kind during the study period and efficiency in the industry (including plant availability) does not increase. FERC emphasizes that it believes these sensitivities are unrealistic.
- *Two Intermediate Scenarios*. Gas prices remain constant relative to coal, but other conditions in the industry favor coal.
- *Four Expanded Transmission Cases and Scenarios*. Four different expanded transmission scenarios were developed in response to criticism of FERC assumptions about transmission limitations, particularly the assumption that there would be no increase in bulk transmission between regions.

2.2 The FERC FEIS Findings

Emissions: Summary

In general, FEIS competition scenarios showed emissions changing by three percent or less from comparable base cases.

- National NO_X emissions from power plants are projected to be higher than in the base case by less than 2 percent under both the Competition-Favors Coal and Low-Response scenarios. National NO_X emissions are projected to be lower by three percent in the Competition-Favors-Gas Scenario.

- National CO_2 emissions in 2010 are projected to be higher by less than one percent in the Competition-Favors-Coal and Low-Response scenarios, and to be lower by three percent in the Competition-Favors-Gas Scenario.
- National SO_2 emissions are projected to decrease throughout the study period in accordance with the nationwide cap on SO_2 mandated by Title IV of the Clean Air Act of 1990. The proposed rule will not affect the timeframe for national SO_2 emissions reductions.
- Emissions of mercury are projected to increase by two percent in the Competition-Favors-Coal Scenario, to remain constant in the Low Response Scenario, and to be lower by one to three percent in the Competition-Favors-Gas Scenario.
- Impacts on water and land use are found to be small in all scenarios.

NO_X and CO_2 Emissions

The tables and charts below provide more details on the FEIS NO_X and CO_2 emissions projections. Table 2.1 presents the NO_X emissions projections for both base cases and both competition scenarios. In presenting this, we follow FERC, comparing the base case that favors gas (with lower gas prices) to the "Competition-Favors-Gas" scenario. Because both scenarios include the same gas price assumptions, the difference in emissions between the two is what FERC projects to be the emissions impacts of Order 888 in a future with lower gas prices. Similarly, we compare the base case that favors coal (with high gas prices) to the "Competition-Favors-Coal" scenario.

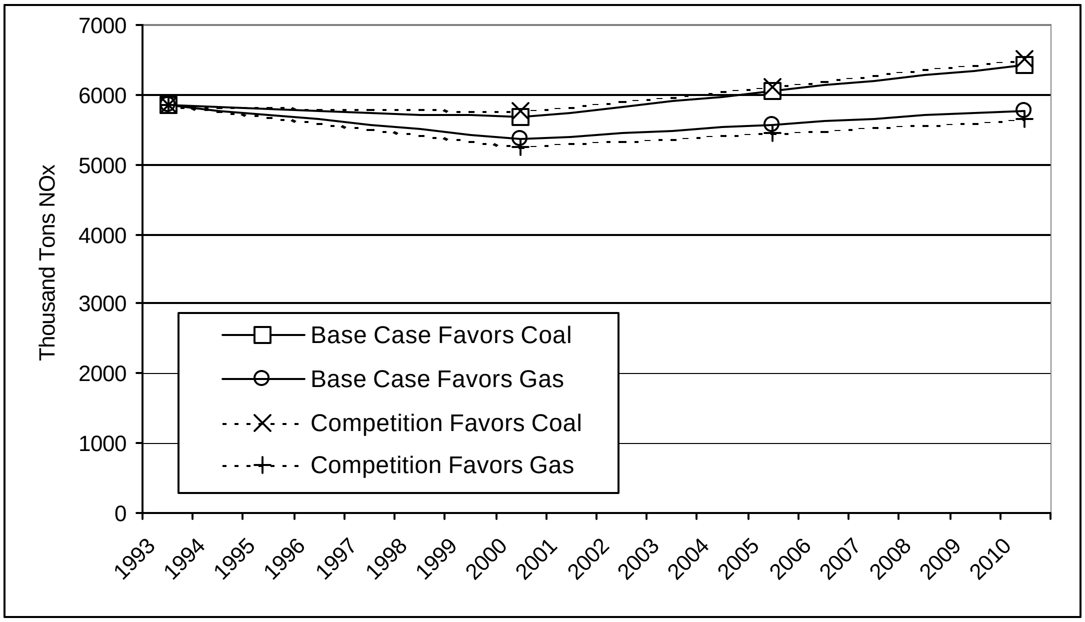
In order to make graphs and tables more readable, we do not show results for FERC's "Low Response" scenario. However, in every case the results for this scenario are very close to the results of the "Competition-Favors-Coal" scenario. (In most cases, the difference between the results of the two scenarios is under 0.5 percent.)

Table 2.1 FEIS Projections of National NO_X Emissions

	1993	2000	2005	2010
Base Case Favors Gas	5,844	5,362	5,579	5,772
Competition-Favors-Gas Scenario	5,844	5,255	5,449	5,638
Percent Change	NA	-2.0%	-2.3%	-2.3%
Base Case Favors Coal	5,844	5,672	6,053	6,426
Competition-Favors-Coal Scenario	5,844	5,763	6,108	6,519
Percent Change	NA	+1.6%	+0.9%	+1.5%

Figure 2.1 presents this same information in the form of a graph. As seen in the percentages above and the figure below, FERC's projections of NO_X emissions depend almost entirely on the assumptions regarding relative coal and gas prices. Their analysis shows very little deviation from the base cases as a result of Order 888.

Figure 2.1 FEIS Projection of National NO_X Emissions



The reduction in NOx emissions in the period 1993 to 2000 reflects FERC's assumption that emission controls are being installed as required by Title IV of the Clean Air Act and the Memorandum of Understanding (MOU) signed by the Ozone Transport Commission states.[2] The increase in emissions after 2000 reflects the assumption that increased generation due to load growth will lead to increasing NOx emissions, even with the new emission controls in place.

Table 2.2 presents FERC's predictions of CO_2 emissions in each of the two base cases and competition scenarios. As with NO_X emissions, FERC's projections of CO_2 emissions depend almost entirely on the assumptions regarding relative coal and gas prices. Their analysis concludes that competition will have very small environmental impacts relative to fuel price dynamics.

Table 2.2 FEIS Projections of National CO_2 Emissions

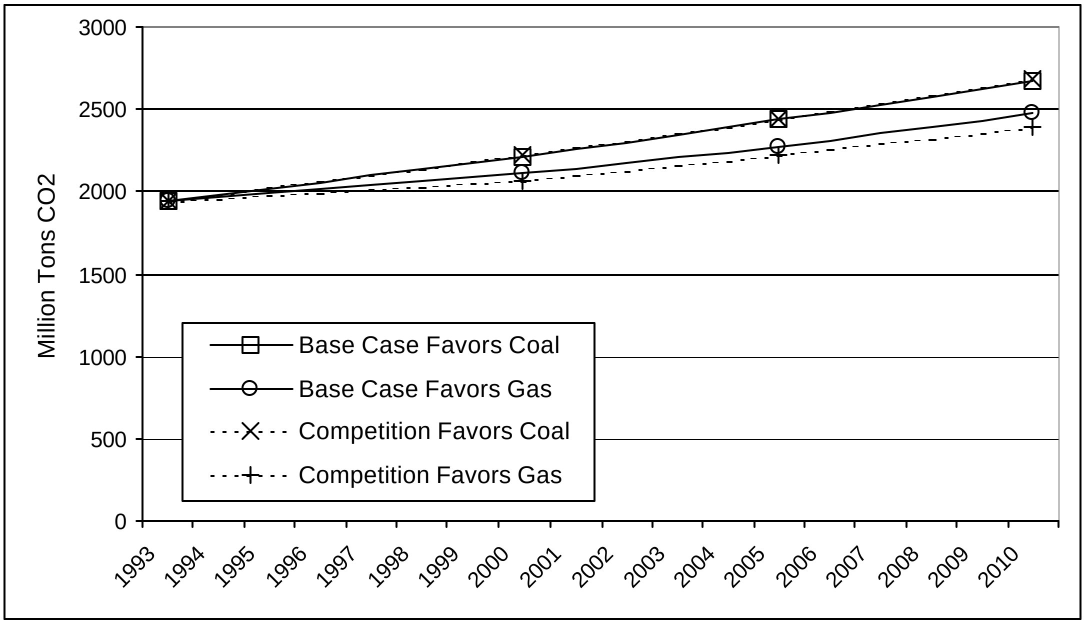
	1993	2000	2005	2010
Base Case Favors Gas	1,942	2,110	2,272	2,475
Competition-Favors-Gas Scenario	1,942	2,069	2,223	2,394
Percent Change	Na	-1.9%	-2.2%	-3.3%
Base Case Favors Coal	1,942	2,210	2,436	2,671
Competition-Favors-Coal Scenario	1,942	2,224	2,442	2,680
Percent Change	Na	+0.6%	+0.3%	+0.3%

Figure 2.2 presents the same information on CO_2 emissions in the form of a graph. Note that, unlike FERC's projection of NO_X emissions, their prediction for CO_2 includes rising

[2] Note that the EIS did not assume that companies would be installing controls in anticipation of EPA's NOx SIP Call rule.

emissions throughout the modeled period, including the period 1993 through 2000. This reflects the fact that there are no CO_2 emission reduction programs in place similar to Title IV of the Clean Air Act or the Ozone Transport Commission MOU.

Figure 2.2 FEIS Projection of National CO_2 Emissions



2.3 The FERC FEIS Conclusions

The FEIS concluded that Order 888 would not have significant environmental impacts, and that any impacts would be outweighed by the economic benefits of the order. The study points out that the "most important factor that would affect changes in national NO_X emissions is the relative competitive position of coal and natural gas." (FERC FEIS, page ES-11)

In sum, if competitive conditions in the electric power industry develop in a way that favors natural gas, Order 888 would lead to environmental benefits because gas generation has less air emissions than coal generation. Conversely, if competitive conditions favor coal, Order 888 would lead to small negative environmental impacts. (FERC FEIS, page ES-1)

The FEIS conclusions focus upon NO_X emissions, because of concerns about ozone nonattainment in certain regions of the country. The study notes that NO_X emissions were a major national problem before Order 888 and will remain so regardless of whether the proposed Order 888 is adopted. (FERC FEIS, page ES-1) The FEIS concludes that implementation of Order 888 will, at worst, contribute only marginally to a significant underlying problem, and in some cases may slightly alleviate the problem. (FERC FEIS, page 8-5)

The FEIS also points out that many other factors affecting the electricity industry could have a greater impact on the environment than Order 888.

> There is understandably considerable uncertainty as to what the future will look like half a decade and more into the next century. Assumptions about electricity demand growth rates, nuclear capacity and utilization, world oil prices, the relative prices of natural gas and coal, market penetration of new generating technologies, and possible changes in environmental regulations all could potentially have much greater impacts on environmental quality than the impact attributable to the proposed rule. (FERC FEIS, page 8-1)

2.4 Coal and Natural Gas Prices: Which FERC Forecast Should We Analyze?

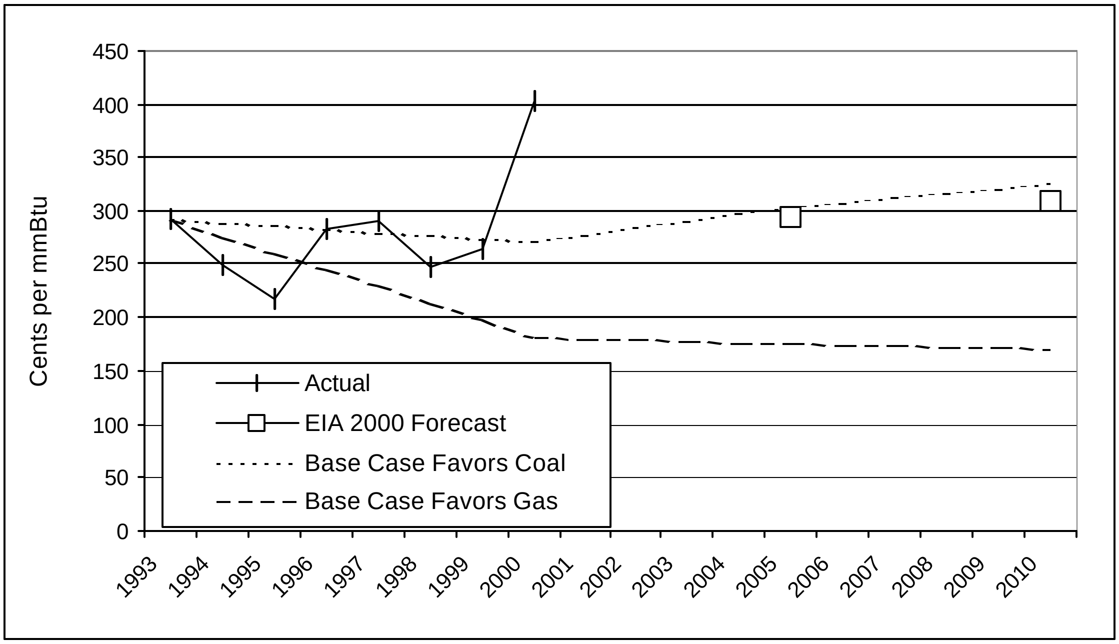
FERC structured its analysis so that a base case with one fuel price assumption should be compared with a competition scenario with the same fuel price assumption. In other words, FERC assumes that Order 888 will not lead to any significant change in fuel prices relative to the base case. Fuel prices are taken as exogenous, or external to the forecast. In fact, FERC forecasts two principal futures, depending on the evolution of fuel prices. From our present vantage point, with data through 2000, it is clear that the fuel price assumptions are much closer to reality for one of these futures than for the other.

Figure 2.3 presents a comparison of FERC's *natural gas* price projections with actual gas prices from 1993 through 2000. Gas prices were lower than both of FERC's forecasts in 1994 and 1995. Since 1995, however, they have tended to be close to or above FERC's high gas price forecast in the High Price Differential Base Case (the base case favoring coal). Thus it is reasonable to take that base case, combined with the Competition-Favors-Coal Scenario, as FERC's projections, given the price patterns that have actually occurred.

Moreover, Competition-Favors-Coal is closer to actual experience as of 2000 than any other FERC scenario, on virtually every indicator that we have examined. Other scenarios are not only less realistic in their assumptions, but also less accurate in their projections. To simplify drastically, Competition-Favors-Coal forecasts more pollution than other FERC scenarios, and by most measures actual pollution in 2000 was even greater than the projections in Competition-Favors-Coal. Little would be gained by repeating that finding throughout this report. Therefore, we will focus most of our attention on the Competition-Favors-Coal Scenario, and the contrast between it and the corresponding base case.

The fact that gas prices have been high and that the Competition-Favors-Coal Scenario has turned out to be the most accurate has important ramifications regarding the environmental impacts of Order 888. The Competition-Favors-Coal Scenario is the one that leads to increased emissions of NO_X, CO_2 and other pollutants – due to higher levels of coal generation. As we will see, actual emissions have generally been even higher than the scenario forecast.

Figure 2.3 US Gas Prices for Electric Utilities: FERC Projections Compared with Actual Prices From 1993 to 2000 and Current Projections for Later Years



Furthermore, as indicated in Figure 2.3, current Energy Information Administration (EIA) projections of natural gas prices in 2005 and 2010 are quite close to FERC's projection in the Competition-Favors-Coal Scenario, and are much higher than the Competition-Favors-Gas Scenario. This further supports the point that the Competition-Favors-Coal Scenario has turned out to be the most relevant competition scenario modeled by FERC.

FERC's forecast of 2000 *coal* prices in the High Price Differential Base Case (the base case favoring coal) is slightly higher than actual experience. The actual coal price in 2000 was $1.20/MMBtu, and FERC's forecasted price was $1.29/MMBtu – roughly seven percent higher.

3. Comparison Of FERC's Emissions Projections With Recent Experience

3.1 Compiling Actual Data

We use the Energy Information Administration's Electric Power Annual reports as our source for actual electricity generation and emissions data. (EIA 1993-2000) Volume I of the Electric Power Annual contains data on power plant generation and capacity, while Volume II contains data on power plant air emissions.

As of the time this report was prepared, Volume I was available for all years from 1993 through 2000, while Volume II was only available through 1999. Consequently, in order to make comparisons with FERC's projections, we estimated the 2000 NO_X and CO_2 emissions. Our "actual" 2000 emissions are estimated, for each region of the country, by multiplying actual 2000 fossil generation times the emissions-per-fossil-generation rate experienced in 1999. Given that the amount of generation from fossil plants is the primary factor affecting air emissions (especially CO_2), this approach provides a good approximation of regional air emissions in 2000. Nonetheless, actual 2000 emissions may turn out to be slightly different than those presented here.

Furthermore, in comparing the FEIS's projections for the year 2000 to actual data for 1995 through 2000, we encounter some problems with the consistency of the data. In sum, FERC's methodology for presenting electricity generation and air emissions was not consistent with the methodology used by EIA, our source of actual data. In order to make the two sources of data consistent, and to keep FERC's numbers internally consistent, we have made a few adjustments to FERC's data. These adjustments are described in more detail in Appendix A.

3.2 National and Regional NO_X Emissions

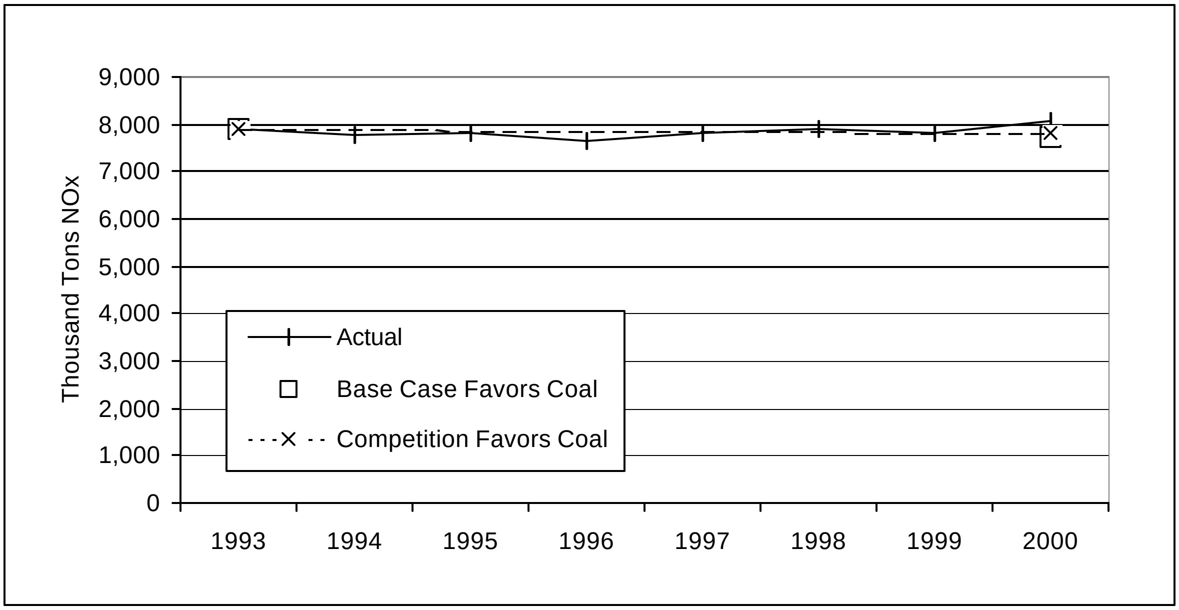
For the US as a whole, the FEIS projections for 2000 NO_X emissions were lower than actual emissions in that year. Table 3.1 compares the FEIS projections with actual 2000 emissions. The FEIS base case projection was lower than actual by 5.4 percent while the Competition-Favors-Coal Scenario emissions were lower by 4.3 percent.

Table 3.1 National NO_x Emissions: Actual Versus FERC Projections (1000 tons)

Base Case or Scenario	NO_X Emissions in 2000	Difference from Actual	Percent Difference
Actual 2000 Emissions	8,190	---	---
Base Case Favoring Coal	7,746	-444	-5.4%
Competition-Favors-Coal Scenario	7,837	-353	-4.3%

The same information is presented graphically in Figure 3.1. This figure also presents actual NO_X emissions for the interim years, 1993 through 2000. We start with 1993 emissions because FERC used actual 1993 data as its base year data. National NO_X emissions decreased from 1993 through 1996, and then began climbing. As noted, in 2000, actual NOx emissions were 4.3 percent above FERC's highest emission scenario, Competition-Favors-Coal.

Figure 3.1 National NOx Emissions: Actual Versus FERC Projections



While FERC's FEIS underestimated national NOx emissions, it did not underestimate emissions in all of the regions. FERC's estimates were higher than actual in some regions and lower than actual in others. Below we present FERC's results versus actual emissions for four regions in the eastern U.S., New England, the Mid-Atlantic, the South Atlantic and the East North Central (the northeastern Midwest). We focus on these regions because much of the controversy over FERC's FEIS focused on potential increases in air emissions in this area of the country. A map of these regions appears in Appendix B.[3]

In New England, actual NOx emissions continued their downward trend during 1994-96, falling well below FERC's forecast by 1996. This trend was due to decreasing in-region generation (increasing power imports) and to the installation of controls pursuant to the Ozone Transport Commission's Memorandum Of Understanding. In 1997, New England NOx emissions spiked, rising well above FERC's predictions , as fossil generation rose to make up for nuclear plant outages. And in 2000, actual emissions were five percent above FERC's forecast for the year.

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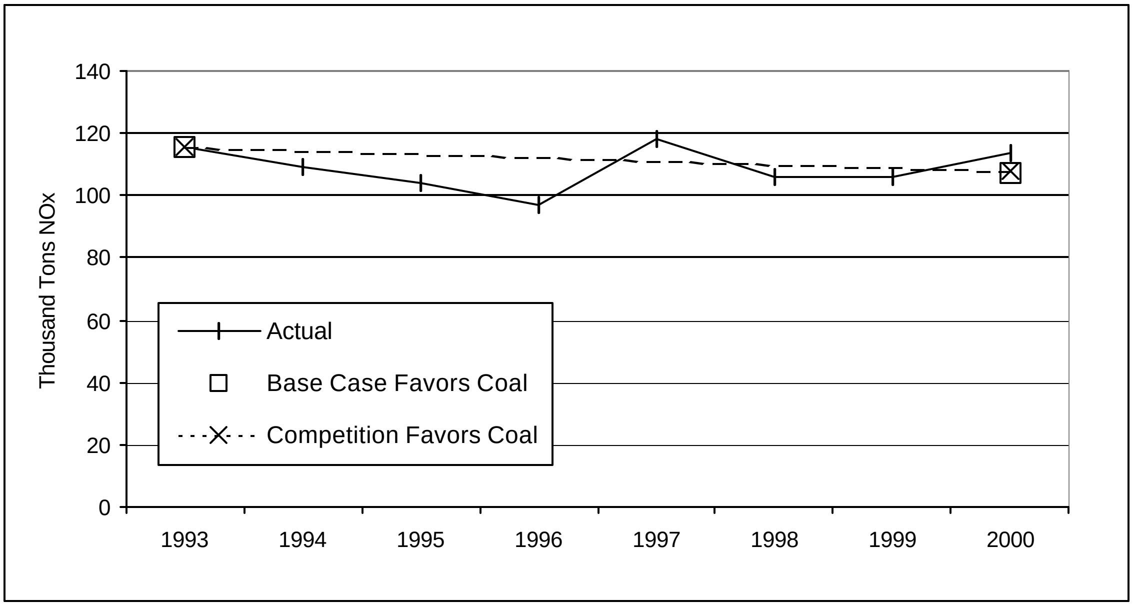
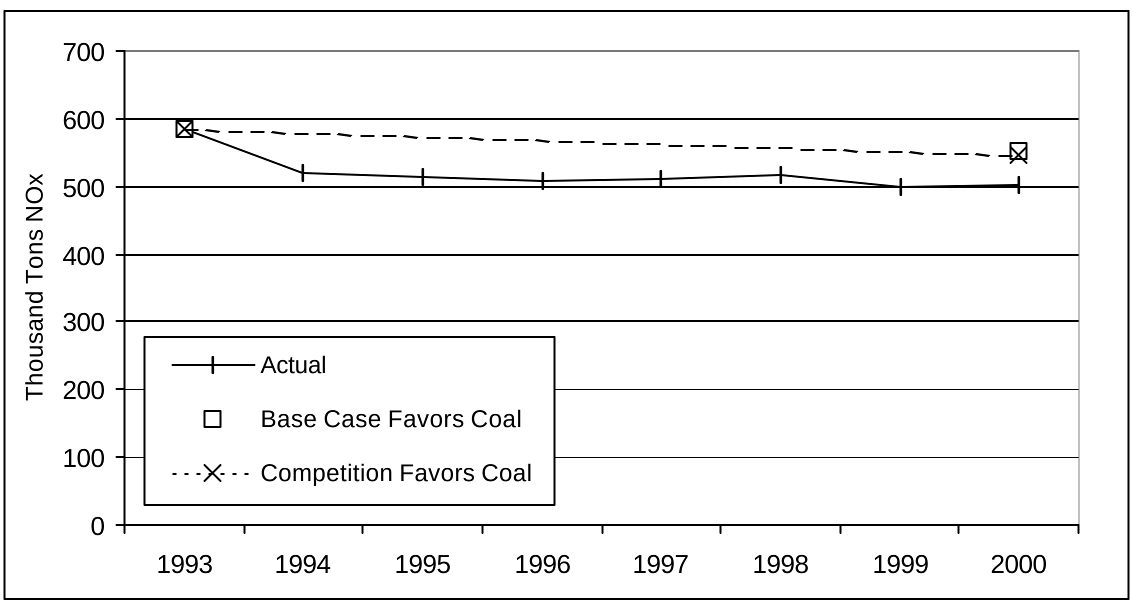
[3] The New England region includes Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. The Mid-Atlantic region includes New York, Pennsylvania and New Jersey. The East North Central region includes Wisconsin, Michigan, Illinois, Indiana, and Ohio. The South Atlantic region includes Delaware, Maryland, Washington DC, West Virginia, Virginia, North Carolina, South Carolina, Georgia, and Florida.

Figure 3.2 New England NOx Emissions: Actual Versus FERC Projections



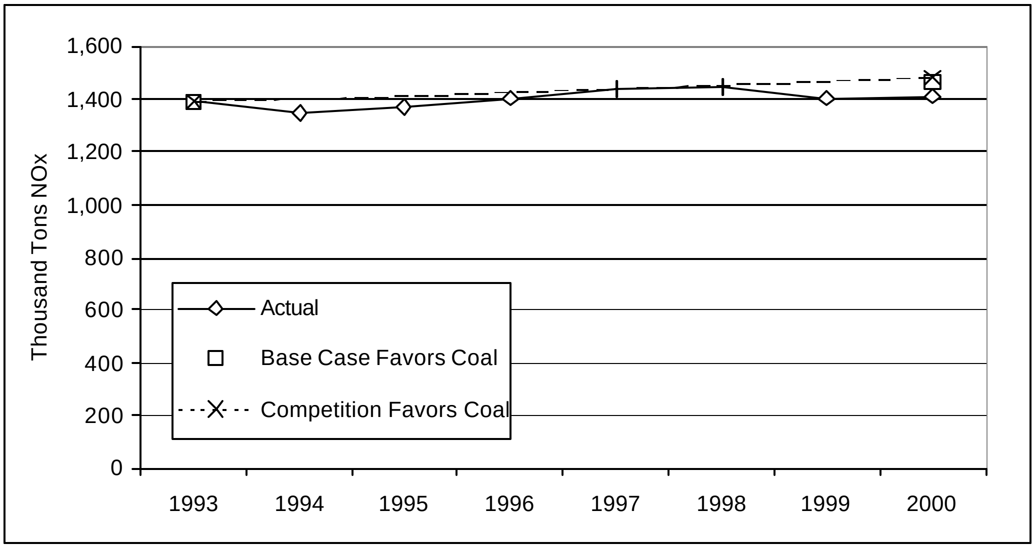
Mid-Atlantic NOx emissions were significantly lower than FERC scenarios for the entire period, the result primarily of an 11-percent drop between 1993 and 1994. Coal-fired generation in the Mid-Atlantic decreased between these two years, but there have been NOx controls installed as well, as the drop in coal-fired generation is not large enough to explain this emission reduction. (See the discussion of Mid-Atlantic CO_2 emissions with Figure 3.8)

Figure 3.3 Mid-Atlantic NOx Emissions: Actual Versus FERC Projections



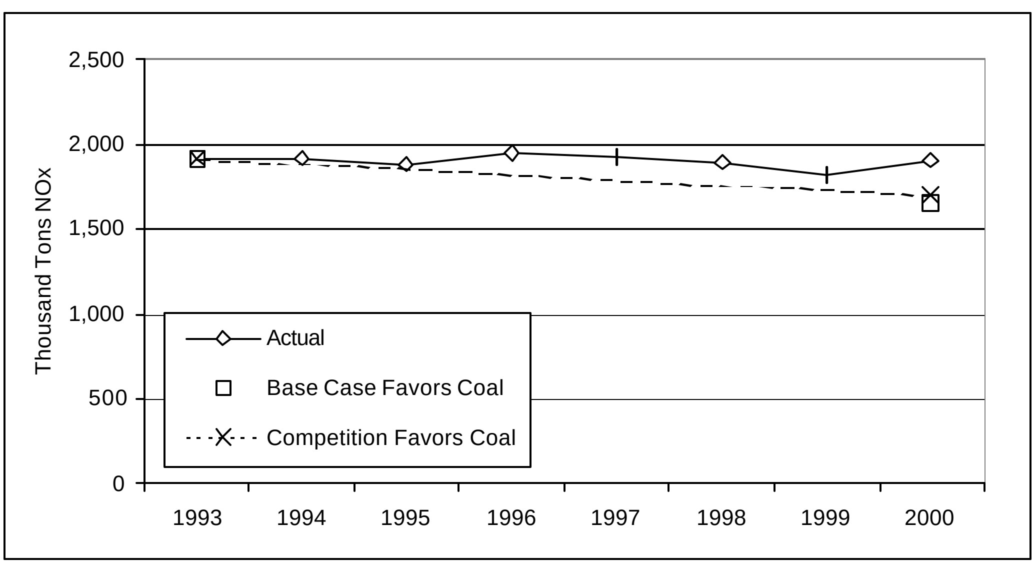
In the Southeast, NOx emissions rose steadily through the first three years after Order 888, following FERC's Competition-Favors-Coal prediction in 1997 and 1998. Coal-fired generation in the region increased in each of these years. Emissions then decreased in 1999. In 2000, emissions were below FERC's forecast.

Figure 3.4 South Atlantic NOx Emissions: Actual Versus FERC Projections



In the East North Central (the northeastern Midwest) region, actual NOx emissions increased significantly between 1995 and 1996 and remained above FERC's projection for the entire period. In 2000, actual emissions were 11 percent above FERC's Competition-Favors-Coal Scenario. As we will discuss in Chapter 5, the increases in NOx emissions seen in 1996 and 2000 are primarily the result of increased coal-fired generation.

Figure 3.5 East North Central NOx Emissions: Actual Versus FERC Projections



3.3 National and Regional CO_2 Emissions

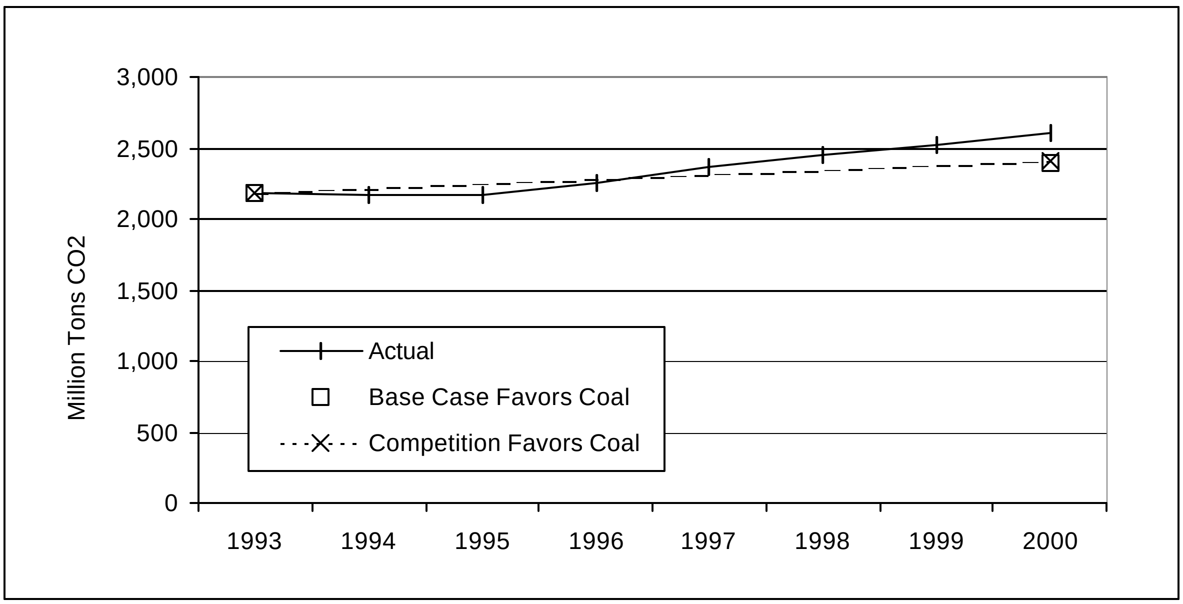
As with NOx, the FEIS projections of CO_2 emissions in 2000 were lower than actual emissions in that year. However in the case of CO_2, the difference between the projected and actual numbers is larger. Table 3.2 compares the FEIS projections with actual 2000 emissions. The FEIS base case projection was lower than actual by 8.5 percent, while the Competition-Favors-Coal Scenario emissions were 7.9 percent below actual.

Table 3.2 National CO_2 Emissions: Actual Versus FERC Projections (million tons)

Base Case or Scenario	CO_2 Emissions in 2000	Difference from Actual	Percent Difference
Actual 2000 Emissions	2,611	---	---
Base Case Favoring Coal	2,390	-221	-8.5%
Competition-Favors-Coal Scenario	2,404	-207	-7.9%

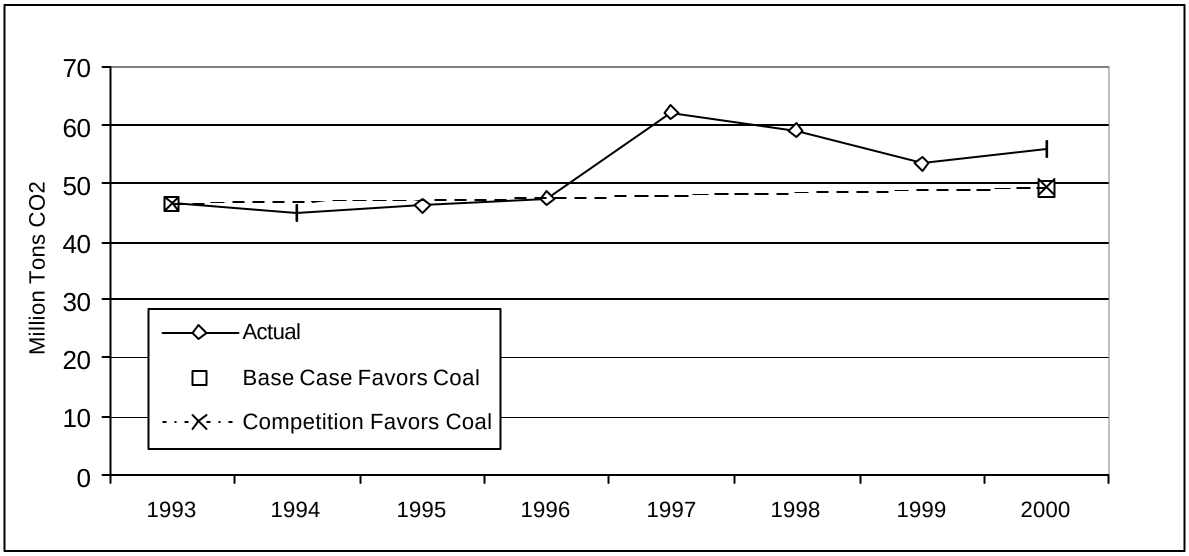
Figure 3.6 shows the same information in graphical form. While all four FERC scenarios (including Base Case Favors Gas and Competition-Favors-Gas, not shown here) predicted falling NOx emissions over this period, all four scenarios predict rising CO_2 emissions.

Figure 3.6 National CO_2 Emissions: Actual Versus FERC Projections



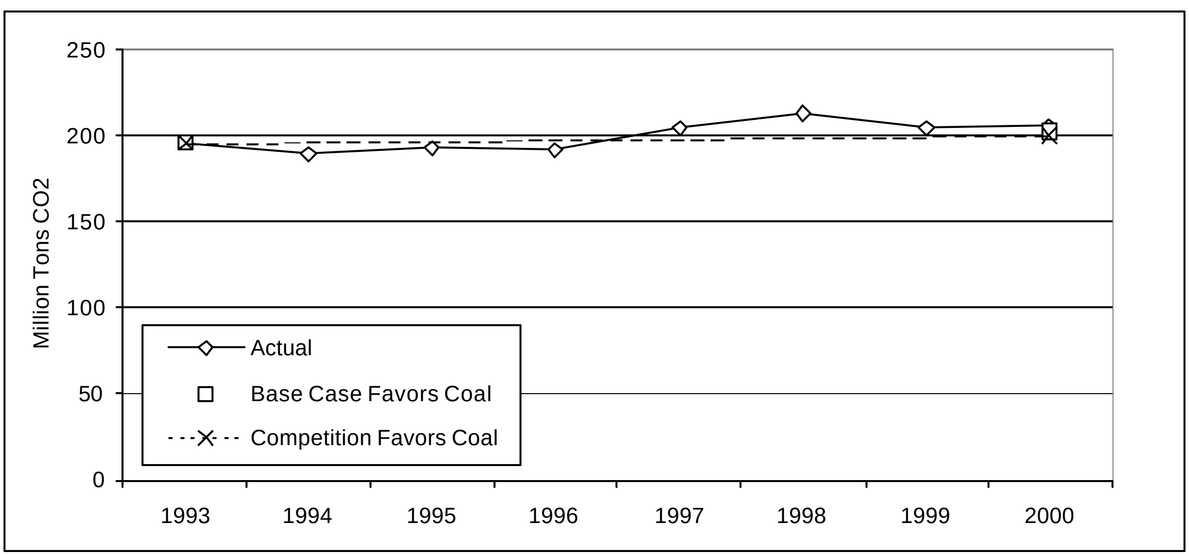
Turning to the regions, we find that FERC projections are generally lower relative to actual emissions for CO_2 than for NOx. In New England, CO_2 emissions follow the same general trend as NOx, except they do not decline after the sharp increase in 1997. They come down slightly in 1998 and then rise again sharply. The increase in 2000 is due to a 17 percent increase in coal-fired generation in New England. However, because the region's coal plants have effective NOx controls, NOx emissions do not rise in 2000 as much as CO_2 emissions.

Figure 3.7 New England CO_2 Emissions: Actual Versus FERC Projections



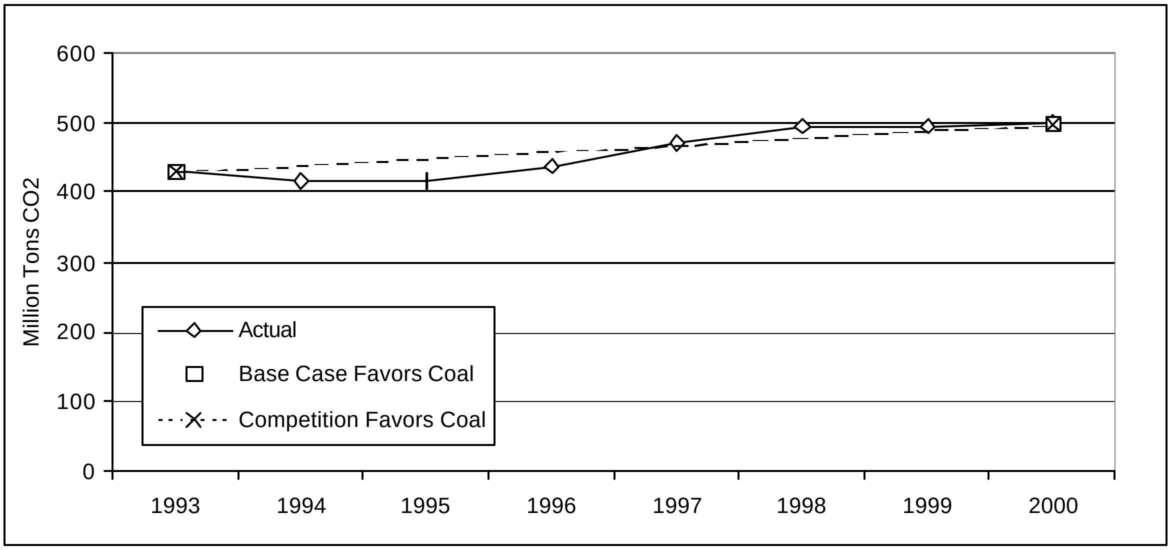
Mid-Atlantic CO_2 emissions generally follow the same trend as NOx emissions in the region (shown in Figure 3.3 above). However, the decrease in emissions between 1993 and 1994 is not as pronounced as the decrease in NOx emissions. (NOx emissions fall by 11 percent, while CO_2 emissions fall by four percent.) This indicates that the large decrease in NOx emissions was due to both the reduction in fossil generation and the installation of NOx controls.

Figure 3.8 Mid-Atlantic CO_2 Emissions: Actual Versus FERC Projections



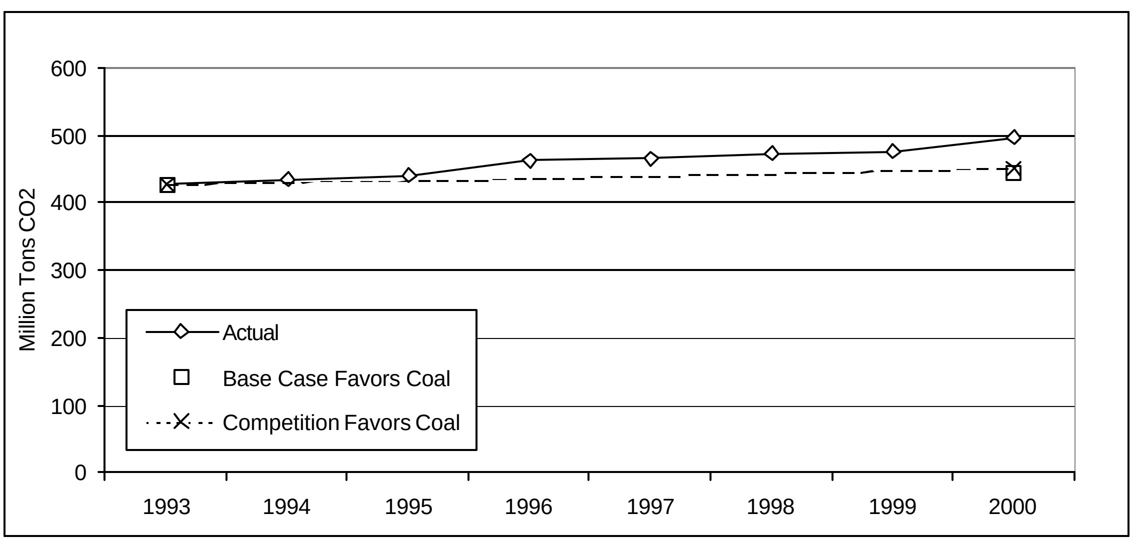
South Atlantic emissions of CO_2 rise faster and climb higher relative to the FERC projections than the region's NOx emissions. NOx emissions in this region never rise above FERC's Competition-Favors-Coal Scenario; CO_2 emissions, however, rise above this scenario in 1998 and 1999 and end up just slightly above it in 2000.

Figure 3.9 South Atlantic CO_2 Emissions: Actual Versus FERC Projections



Emissions of CO_2 in the East North Central region are similar to the region's NOx emissions in that they remain above FERC's projections for the entire period. However, while NOx emissions trended down over this period, CO_2 emissions rose steadily. Emissions ended the period 17 percent above 1993 levels in 2000.

Figure 3.10 East North Central CO_2 Emissions: Actual Versus FERC Projections



3.4 Summary

Comparing actual emissions to FERC's projections at the national level, we find that both actual NOx and CO_2 emissions in 2000 were above FERC's Competition-Favors-Coal Scenario. Of the four regions we reviewed, two have 2000 NOx emissions above this scenario and three have CO_2 emissions above this scenario.

While we did not analyze mercury emissions in 2000, it is likely that the FEIS projections underestimated these emissions as well because the FEIS underestimated coal generation. Coal is the major source of mercury emissions among the fuels used in electricity generation.

In chapters 4 and 5, we investigate which of FERC's assumptions about the future could be the causes of this underestimation of emissions. Assessment of these causes can help guide future investigators as they make their own forecast assumptions.

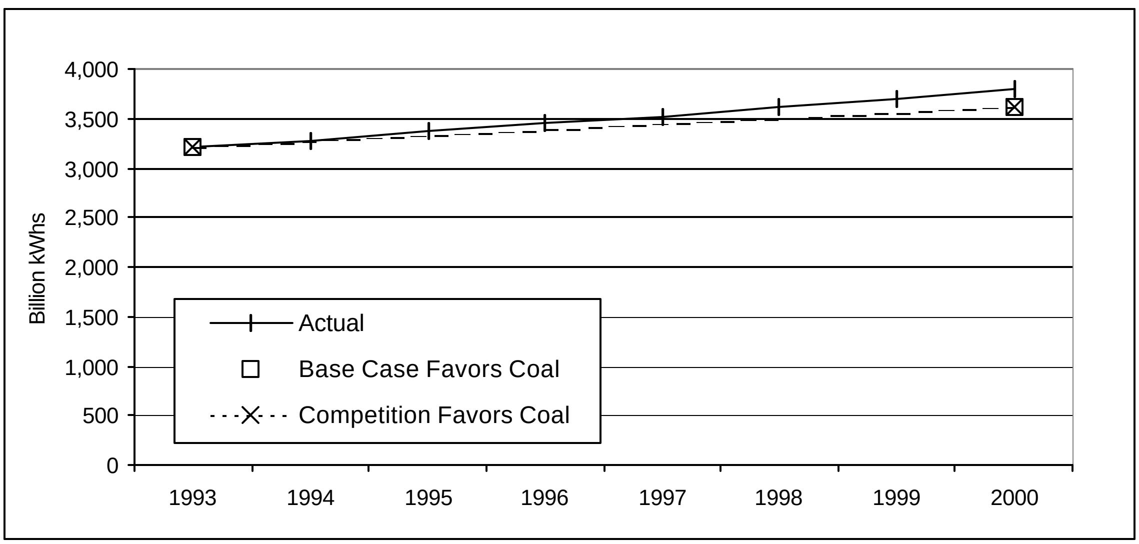
4. Electricity Generation and Consumption

4.1 National Electricity Generation

In Chapter 3 we illustrated how both FERC's base case favoring coal and its Competition-Favors-Coal Scenario underestimated air emissions during the five years following Order 888. (Recall that Competition-Favors-Coal is not only the most appropriate FERC scenario, but also the one with the highest emissions.) Here, we investigate generation at the national level and generation and consumption in several regions to investigate why FERC's emissions projections were low.

FERC's projection of national electricity demand from 1993 to 2000 was lower than actual experience, as indicated in Figure 4.1. FERC predicted average annual load growth of 1.8 percent; while actual load growth averaged 2.4 percent per year.[4] FERC's projection of electricity generation in the Competition-Favors-Coal Scenario turned out to be 175 TWh (4.6 percent) below the actual figure in 2000.

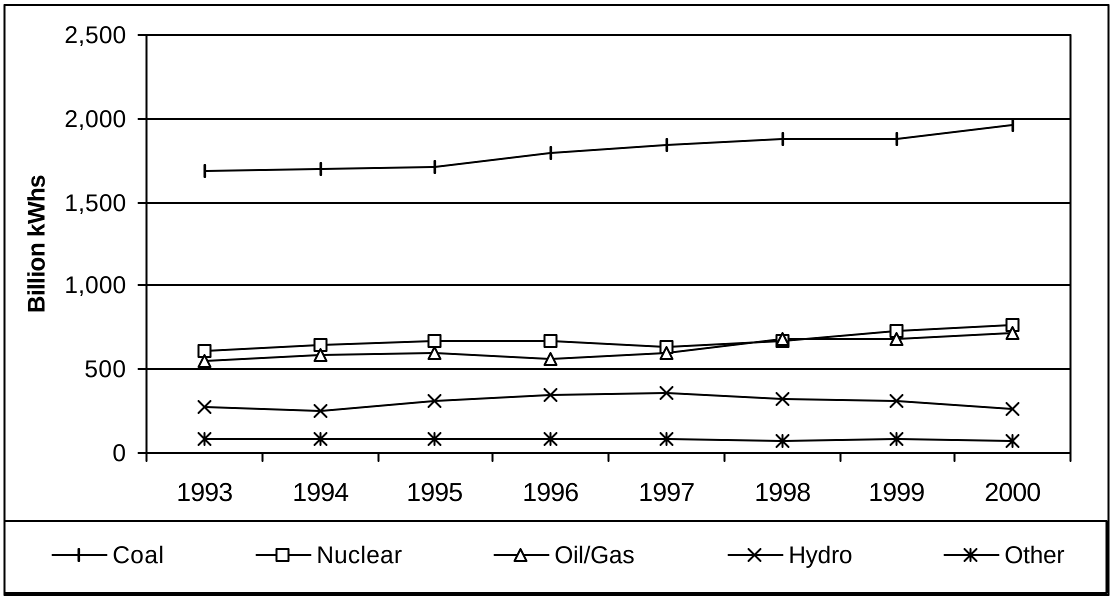
Figure 4.1 National Generation: Actual Versus FERC Projections



Looking at national generation by fuel type in Figure 4.2, we see that the largest absolute increase between 1993 and 2000 came from coal-fired generation. There was also considerable increases in generation from nuclear and oil/gas-fired generation. For all of the increase in US generation from 1993 through 2000, 47 percent of the increased generation came from coal-fired plants, 30 percent came from oil/gas-fired plants, and 27 percent came from nuclear plants. Generation from hydro and other plant types decreased slightly.

4 Data presented later in this chapter reveals that the growth in U.S. generation was due to load growth within the U.S. and not to an increase in power exports.

Figure 4.2 National Generation by Fuel Type



The "Other" fuel category includes geothermal, wind, solar photovoltaics and biomass generation.

Table 4.1 presents the capacity factors of the five fuel types, for all US plants from 1993 through 2000. It shows that coal plants have experienced steadily increasing capacity factors over this period, consistent with the trend toward increased generation. Note that coal plants could increase their capacity factors even more over time, where the US average could technically reach 80 to 85 percent if the electricity demand were high enough and the coal economics were favorable enough. Table 4.1 shows that nuclear plants have also experienced steadily increasing capacity factors over this period, with capacity factors reaching exceptionally high levels of 87 and 90 percent in 1999 and 2000.

Table 4.1 Capacity Factors of US Power Plants from 1993 Through 2000

Fuel / Year	1993	1994	1995	1996	1997	1998	1999	2000
Coal	62%	62%	63%	65%	67%	68%	68%	71%
Nuclear	70%	74%	78%	77%	71%	79%	87%	90%
Oil & Gas	26%	28%	27%	25%	27%	31%	30%	29%
Hydro	31%	28%	34%	38%	40%	36%	34%	29%
~~Other~~	~~72%~~	~~71%~~	~~71%~~	~~70%~~	~~65%~~	~~42%~~	~~54%~~	~~50%~~
Total	48%	48%	50%	50%	51%	53%	53%	53%

FERC's underestimation of electricity generation clearly has important implications for the FEIS projections of air emissions. In 2000 FERC underestimated generation in all three of the major fuel categories: coal, nuclear and oil/gas. Underestimates of coal and oil/gas will lead to underestimates of NO_X and CO_2 emissions, while underestimates of nuclear generation will lead to an overestimate of these emissions.

Of the 175 TWh difference between FERC's estimate and actual generation, 70 TWh was due to underestimating generation from coal, and 30 TWh was due to underestimating oil/gas, for a total of 100 TWh from fossil-fired power plants. FERC underestimated nuclear generation by 122 TWh, but this was offset by an overestimate of 47 TWh of hydro and other generation, leading to a total of 75 TWh predominantly from sources with no emissions of NO_X and CO_2. Thus, FERC's underestimation of electricity generation in 2000 includes a larger underestimation of generation from fossil-fired power plants than from zero-emission plants. Consequently, FERC's underestimation of NO_X and CO_2 emissions is slightly greater than its underestimation of electricity load growth.

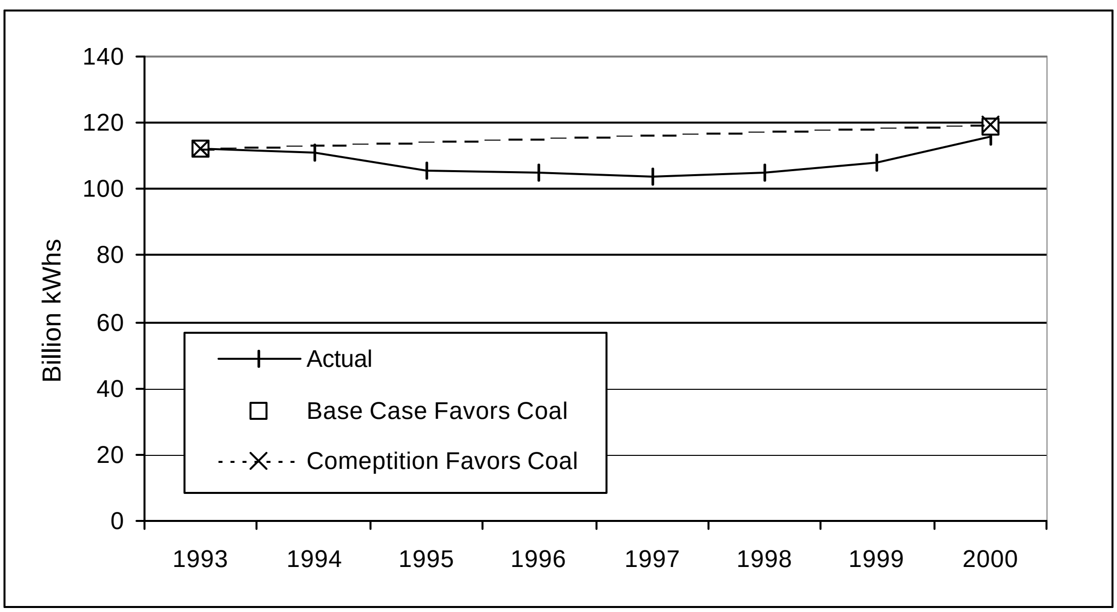
4.2 Regional Generation and Consumption

A major issue of contention during the FEIS process was whether or not low-cost coal-fired plants in the Midwest and Southeast would increase their output in a competitive electric industry as they could more easily deliver their power to higher-cost regions. Below, we focus on electricity generation in the regions of the country examined in Chapter 3, to assess whether or not this has happened. Our conclusion, in brief, is that it did not occur.

New England

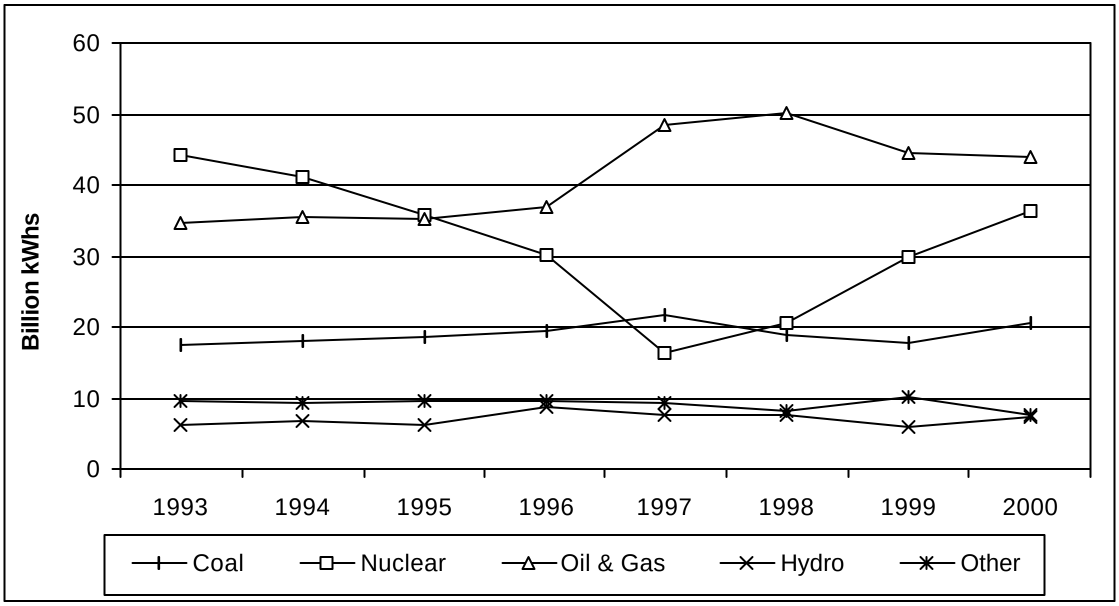
In New England, actual generation was below FERC projections for the period 1995 through 2000, although the gap was narrowing in 1999 and 2000. Figure 4.3 below shows total New England generation versus FERC's projections.

Figure 4.3 New England Generation: Actual Versus FERC Projections



Turning to generation by fuel in New England, we find a significant drop in nuclear generation accompanied by smaller increases in coal and oil/gas generation. Between 1993 and 1997 nuclear generation dropped by nearly 28 billion kWh or 68 percent. For most of 1997 a significant portion of New England's nuclear capacity was unavailable due to unscheduled outages. Nuclear generation rebounded in 1998 through 2000, but it did not reach the levels of the early 1990s, as three of the units down in 1997 were retired rather than restarted.

Figure 4.4 New England Generation by Fuel Type



Gas and oil-fired units in New England increased production considerably to help make up for the lost nuclear generation, and several new gas-fired plants began operation in the region in the period 1998 through 2000. Generation also rose somewhat from the region's few coal-fired plants. These trends are reflected in the region's average capacity factors during this period. The regional nuclear capacity factor fell from 79 percent in 1993 to 32 percent in 1997 and then shot up to 95 percent in 2000. The regional coal capacity factor rose from 66 to 82 percent.

This information on generation by fuel type in New England sheds light on the region's rising NOx and CO_2 emissions, shown in Figures 3.2, and 3.7 in Chapter 3. Although total regional generation actually fell between 1993 and 1999, fossil generation rose, causing an overall increase in NOx and CO_2 emissions, with a pronounced spike in 1997, when the nuclear shortfall was at its worst. Coal-fired generation increased by 17 percent between 1999 and 2000, causing a significant increase in CO_2 emissions.

While fossil generation in New England rose during this period, it was only able to replace about two thirds of the lost nuclear generation, and the region relied heavily on increased power imports to meet loads. Figure 4.5 illustrates the growing electricity deficit in New England and the region's increasing reliance on imported power.[5]

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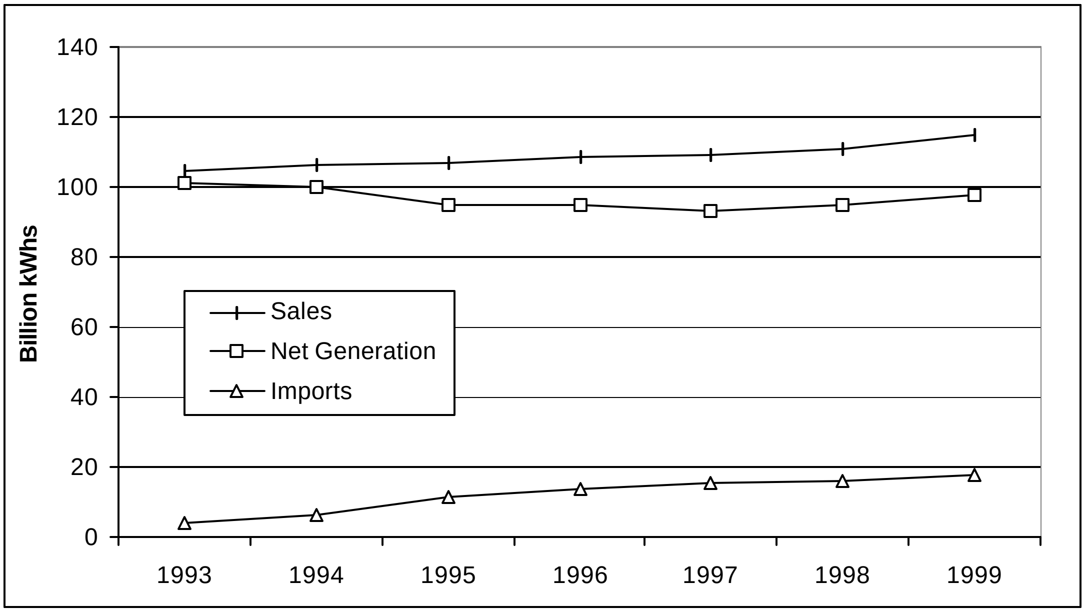
[5] The Generation, Sales and Power Imports figure for New England and other regions do not include data for 2000, because information on 2000 regional sales was unavailable when this report was written.

Figure 4.5 New England Generation, Sales and Power Imports

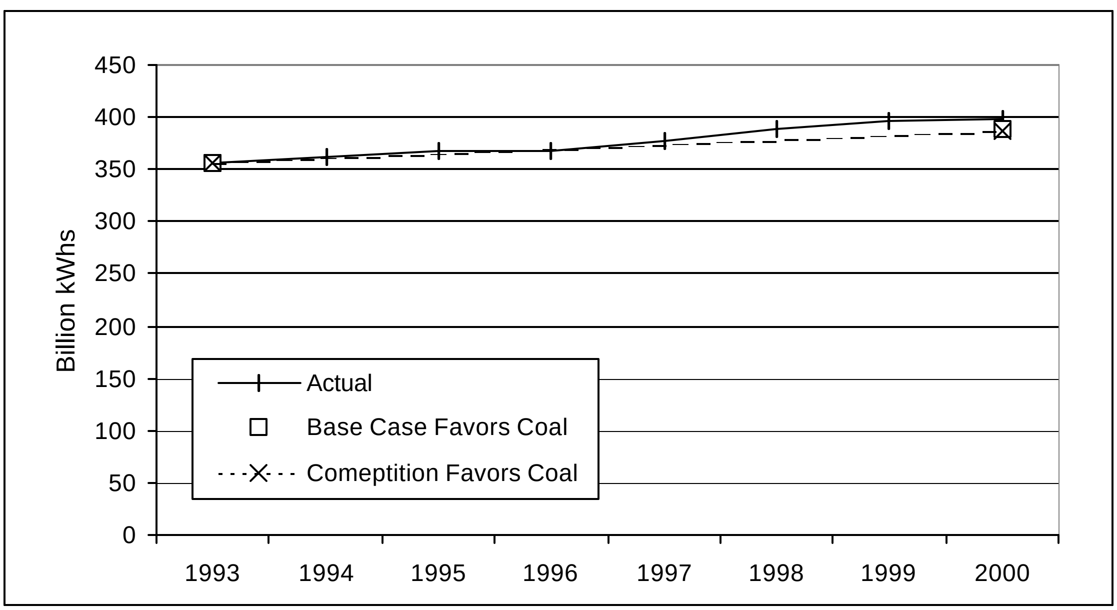


Note: Figure 4.6 shows generation net of losses, so these figures are lower than the generation figures presented in Figure 4.4.

The Mid-Atlantic

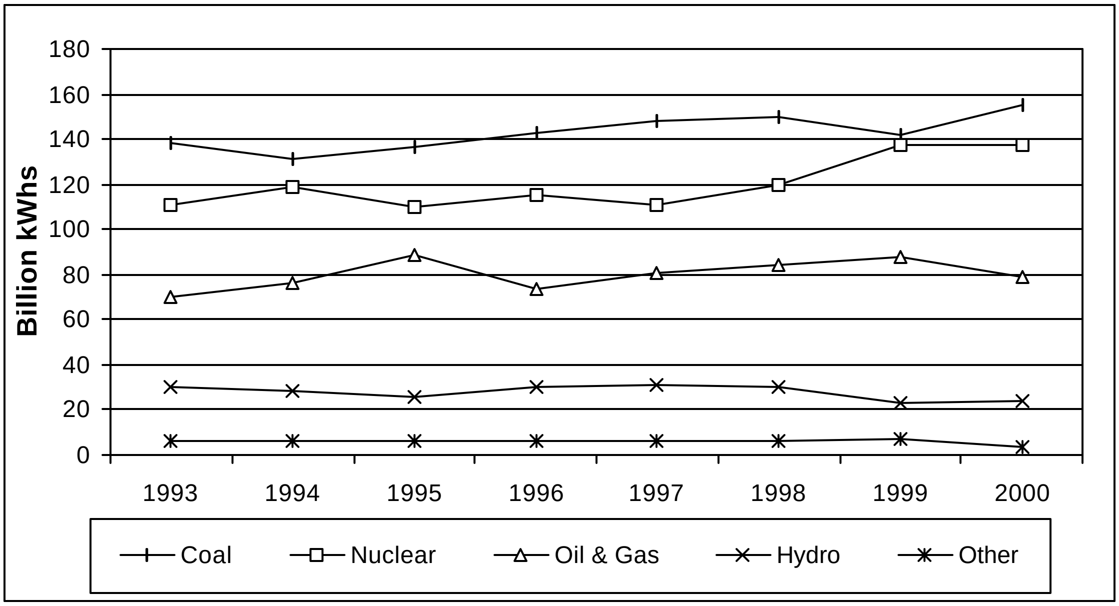
The pattern of generation in the Mid-Atlantic region is quite different from that in New England. Generation grew steadily there during the period of interest, rising just above FERC's Competition-Favors-Coal Scenario in 1998 and 1999 and nearly matching it in 2000.

Figure 4.6 Mid-Atlantic Generation: Actual Versus FERC Projections



Generation using all fuels except hydropower increased in the Mid-Atlantic between 1993 and 2000. Coal-fired generation increased steadily except for a dip in 1999, ending up in 2000 12 percent above 1993 levels. Nuclear generation remained relatively stable until 1997, when it shot up by 24 percent. And gas/oil generation finished 2000 having risen 13 percent over 1993 levels.

Figure 4.7 Mid-Atlantic Generation by Fuel Type

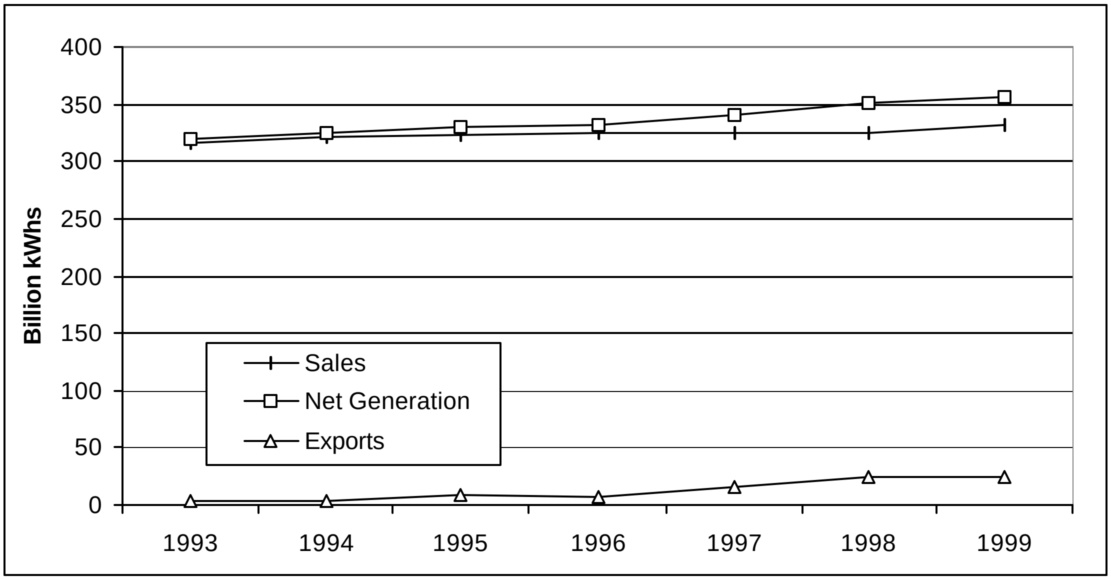


The effects of the reduction in coal-fired generation between 1993 and 1994 can be seen in the regions emissions, shown in Figures 3.3 and 3.8, in Chapter 3. Note that both NO_X and CO_2 emissions fall over this period. However, CO_2 emissions fall much less than NO_X suggesting that NO_X controls were installed during this period.

The region's coal capacity factor started in 1993 at 63 percent and rose erratically to a high in 1998 of 68 percent. The region's nuclear capacity factor was also erratic but finished the period with a strong 87 percent in 1999, up from 73 percent in 1993.

The Mid-Atlantic region was a net exporter of power for the entire period 1993 through 2000. Notably, exports from the region increased significantly during this period, rising by 19 billion kWh. This amount is roughly comparable to New England's imports (see Figure 4.5). However, actual flows are undoubtedly more complicated than a straight transfer between these two regions, since New England also imports power from Canada, and the Mid-Atlantic also exports power elsewhere.

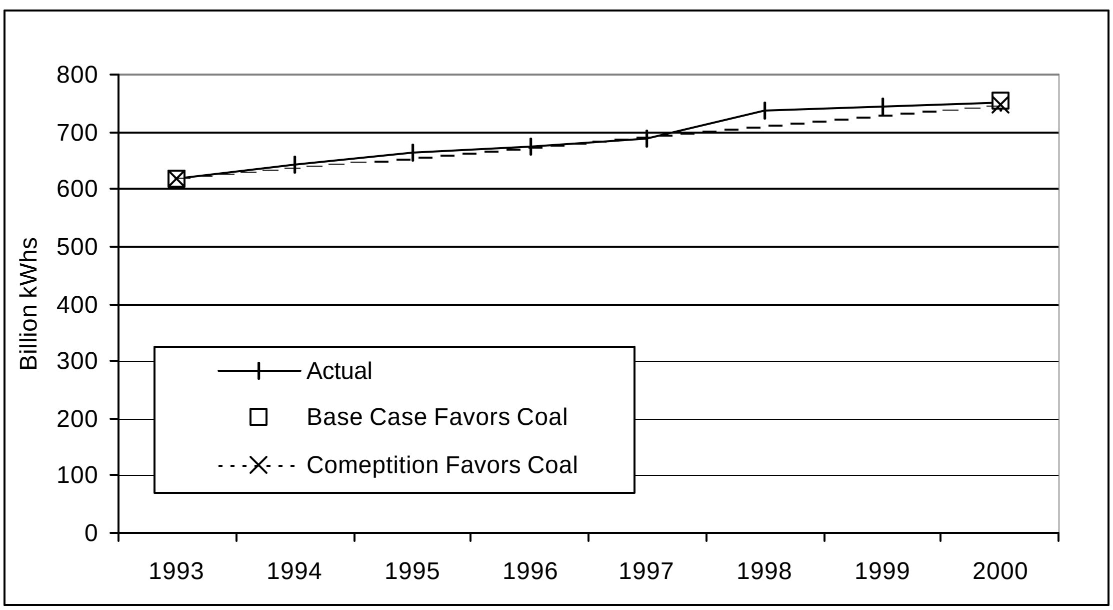
Figure 4.8 Mid-Atlantic Generation, Sales and Power Exports



The South Atlantic

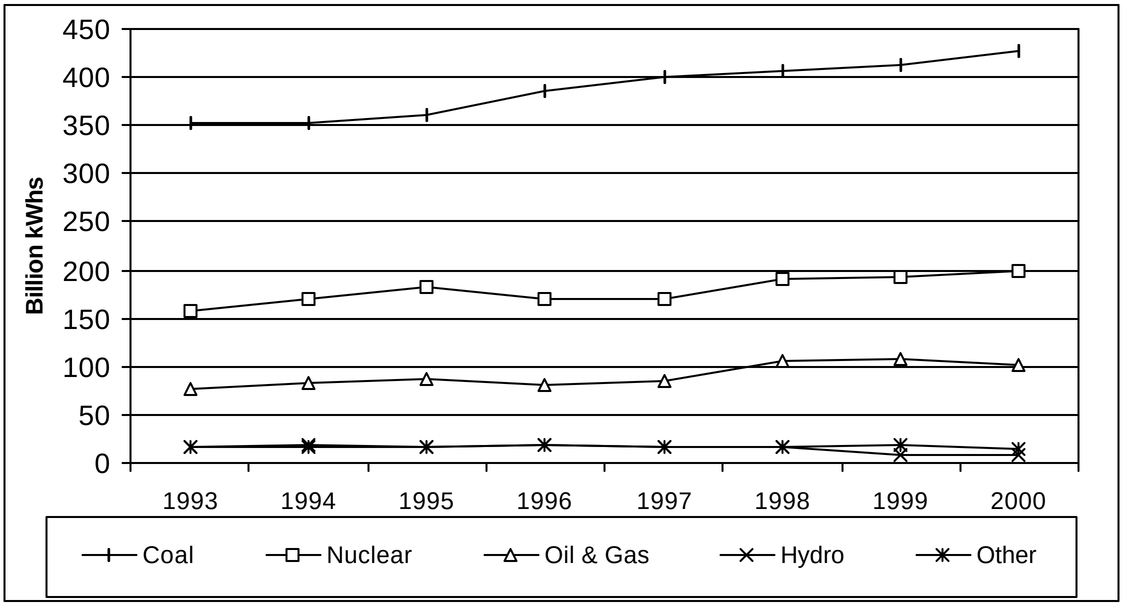
The largest increase in generation of any region of the country during the 1993 through 2000 period came in the South Atlantic, where generation increased by 124 billion kWh, or 20 percent. Notably, FERC predicted rapid growth in generation there; the Competition-Favors-Coal Scenario prediction for 2000 is only 0.3 percent below actual. However, actual generation in 1998 and 1999 is above this scenario.

Figure 4.9 South Atlantic Generation: Actual Versus FERC Projections



As Figure 4.10 shows, nearly half of the increase in South Atlantic generation came at coal-fired plants; coal-fired generation increased by roughly 21 percent. There were slightly larger percentage increases in nuclear generation (26 percent) and oil/gas-fired generation (32 percent).

Figure 4.10 South Atlantic Generation by Fuel Type

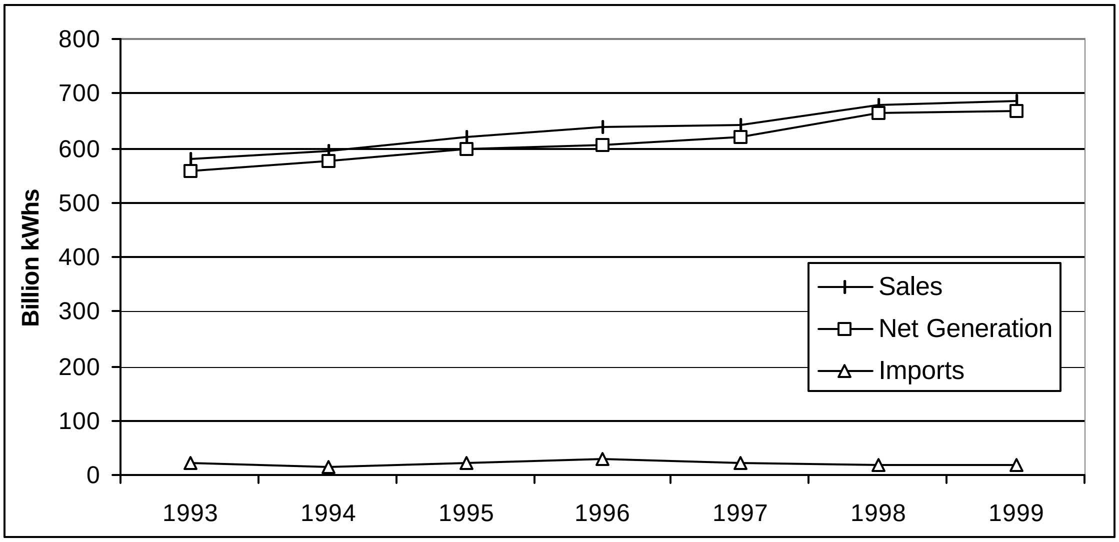


Because FERC's generation estimate for the South Atlantic was fairly accurate, their emissions estimates, seen in Figures 3.4 and 3.9 in Chapter 3, were close to actuals as well. As throughout the FEIS, however, their estimates were significantly lower, relative to actual, for CO_2 than for NO_X. South Atlantic CO_2 emissions rose well above FERC's estimate in 1998 and 1999.

Capacity factors in the South Atlantic rose steadily over the period. The region's coal capacity factor went from 59 percent in 1993 to 68 percent in 2000. The nuclear capacity factor rose from 76 percent in 1993 to 93 percent in 2000. (In 1998, 1999 and 2000 the regional nuclear capacity factor was above 90.)

With this increase in generation, one might expect the South Atlantic to have increased its power exports during this period as well. However, the region remained a net importer for the entire period. The increase in generation simply allowed the region to reduce imports slightly while also meeting some of the fastest load growth in the country.

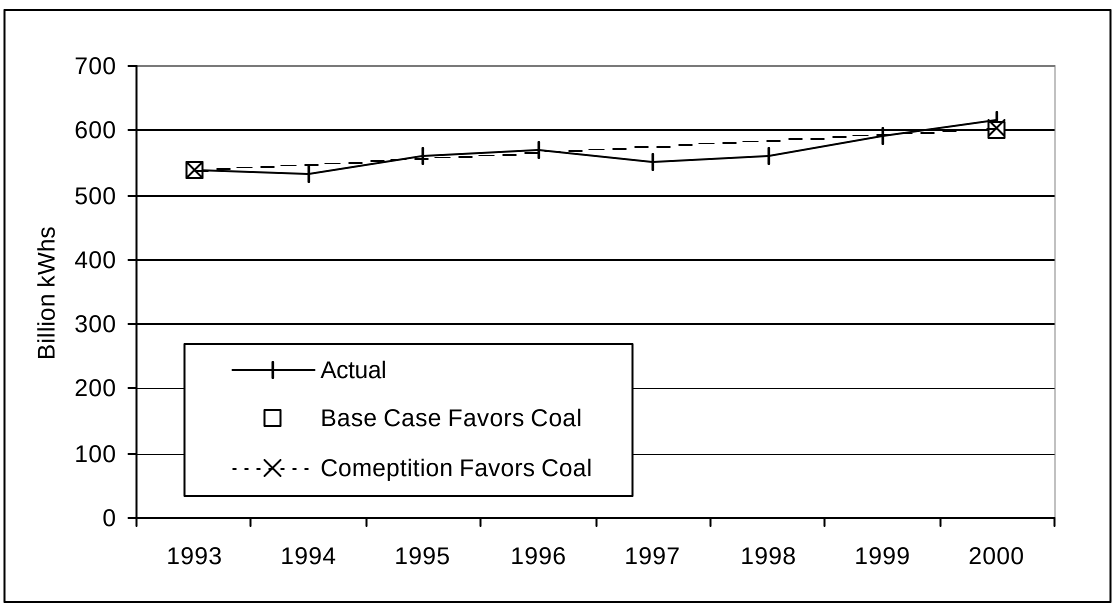
Figure 4.11 South Atlantic Generation, Sales and Power Imports



The East North Central

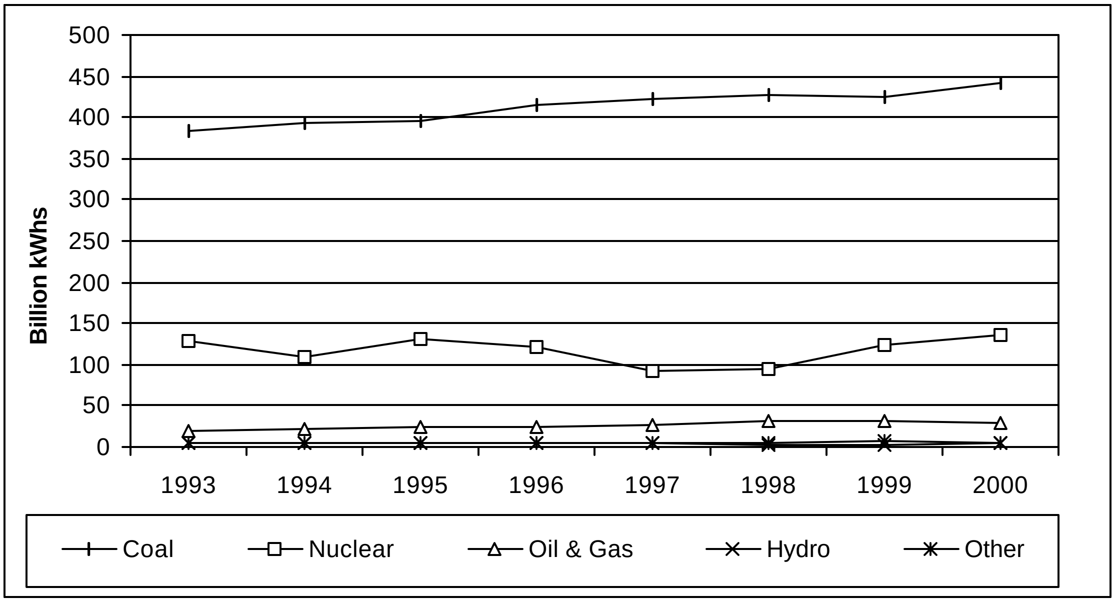
Total generation in the East North Central region traversed FERC's projections, sagging below them in 1997 and 1998 and rising back above them by 2000. As shown in Figure 4.12, total generation finished 2000 two percent above FERC's Competition-Favors-Coal Scenario.

Figure 4.12 East North Central Generation: Actual Versus FERC Projections



As in the Mid-Atlantic and South Atlantic, coal-fired generation rose significantly in the East North Central, rising 15 percent between 1993 and 2000. Nuclear generation trended neither up nor down, and oil/gas generation was up 10 billion kWh or 52 percent.

Figure 4.13 East North Central Generation by Fuel Type

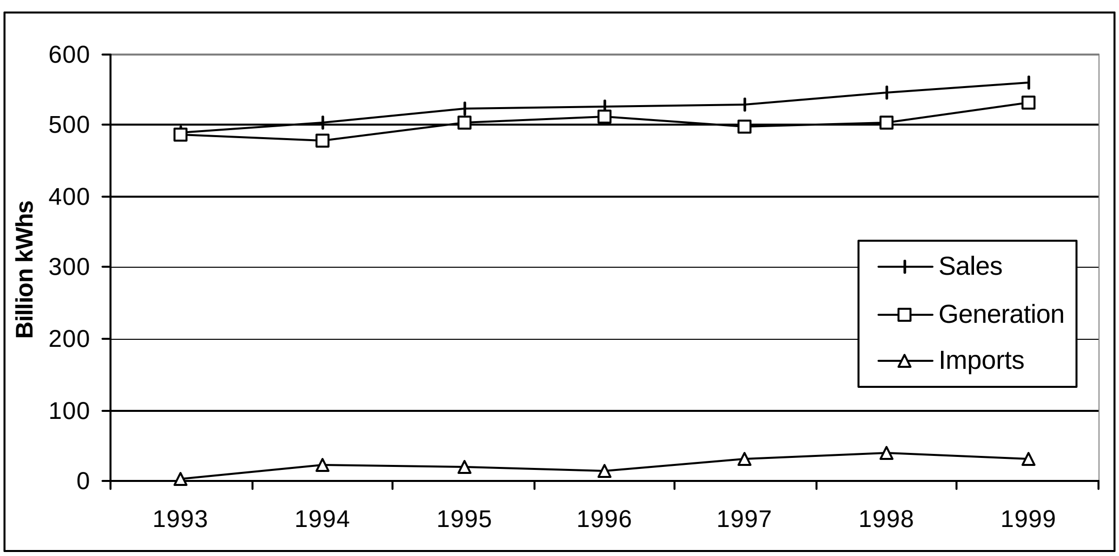


Both NO_X and CO_2 emissions follow the trend of increasing coal-fired generation in the East North Central. As seen in Figures 3.5 and 3.10 in Chapter 3, emissions of both pollutants climb above the FERC predictions with the jump in coal-fired generation in 1996, and they remain above the FERC predictions.

The coal capacity factor for the region started out at 56 percent, climbed steadily and finished out 2000 at 65 percent. The nuclear capacity factor started at 73 percent, was very erratic, falling to 60 percent in 1998, and then rose to 91 percent in 2000.

The East North Central remained a net power importer throughout the period, with the amount of imported power trending slightly upward.

Figure 4.14 East North Central Generation, Sales and Power Imports



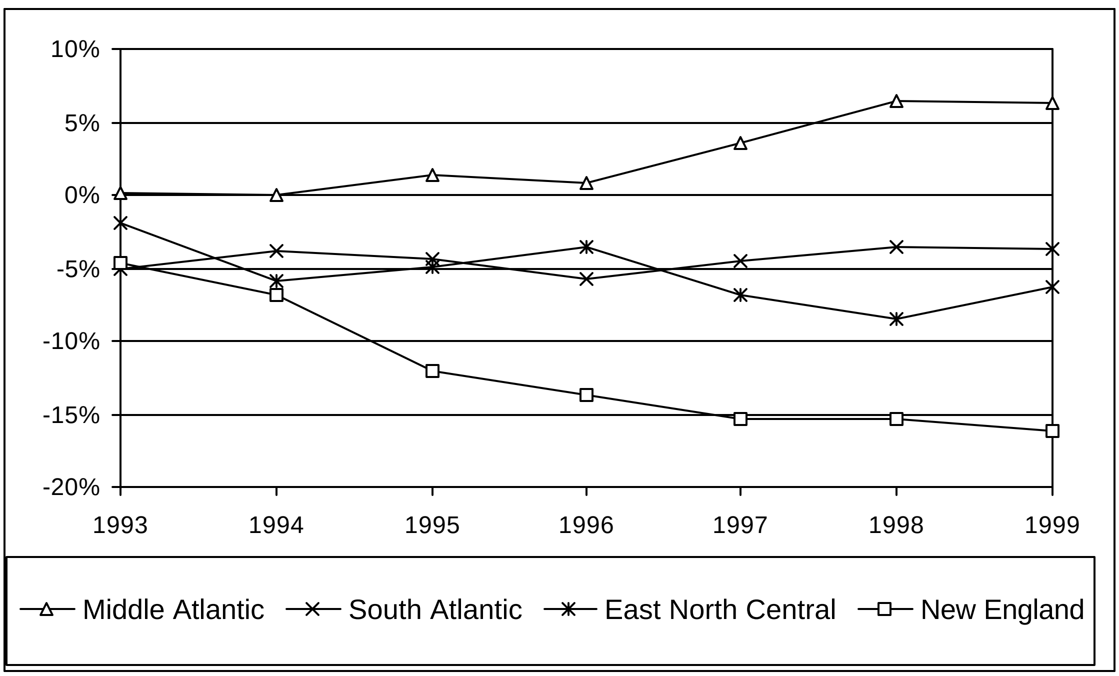
4.3 Summary

US electricity demand and generation increased at a relatively high rate of 2.4 percent per year from 1993 through 2000. Most of the increased generation during this period came from coal and oil/gas plants, while the remainder came from nuclear generation. On average, US coal plant capacity factors increased steadily over this period from roughly 62 percent to 71 percent. Similarly, US nuclear plant capacity factors increased from roughly 70 percent to roughly 90 percent.

National electricity demand and generation grew faster from 1993 through 2000 than FERC predicted in the FEIS. This appears to be the dominant factor explaining why actual NO_X and CO_2 emissions in 2000 turned out to be higher than those predicted by FERC.

With regard to regional generation, Figure 4.15 summarizes the net generation status of our four regions in recent years. Here we see that the Mid-Atlantic was the only region to be a net exporter for the entire period, the other three regions were net importers.

Figure 4.15 Net Generation Surplus for the Four Regions



During the course of the FEIS, many commenters expressed concern that Order 888 would create opportunities for low-cost coal plants in the Midwest and South to increase their generation levels and sell excess power to neighboring high-cost regions such as the Northeast. It appears as though this type of inter-regional transfer of power has not occurred in recent years. The East North Central region has been a net importer throughout this period – with increasing levels of imports over time. The South Atlantic region has maintained a constant level of imports during this study period.

This information on imports and exports reveals that, while the coal plants in the East North Central and South Atlantic did in fact increase their output during this period, it was not to export power to higher cost regions. It was instead to meet load growth *within* their own regions. Load grew in the East North Central region at an average annual rate of 2.3 percent between 1993 and 1999, and in the South Atlantic at 2.8 percent per year during this period.

However, this finding does contradict or disprove the theory that low-cost electricity will more effectively find profitable (high-cost) markets in an industry with open transmission access. In other words, this finding tells us nothing about what low-cost coal plants would have done had load not grown so fast in their own regions.

5. FERC's Modeling Assumptions

5.1 Introduction and Approach

In order to explain the differences between FEIS projections and actual experience in 2000, it is necessary to review the various assumptions that FERC used in its analysis. These assumptions fall within two distinct categories. First, FERC developed a set of assumptions to model the likely impacts of Order 888 on the electricity industry. It is these assumptions, and only these assumptions, that lead to the deviations between the base cases and the associated competition scenarios. Second, there are numerous assumptions that were held constant in all cases – the base cases and all competition scenarios. While this latter group of assumptions has important implications for projections of air emissions, they do not lead to any of the deviations between the base cases and the associated competition scenarios.

We investigate both of these categories of assumptions in the following sections. For each of the key modeling assumptions and associated factors we seek to answer several questions. How did FERC's assumption compare with experience through 2000? Did the factor change over time as a result of increased competition (i.e., Order 888), or did it change as a result of ongoing industry trends? What is the likely impact on air emissions of FERC's assumption, and what is the likely air impact if a revised assumption is used to reflect current knowledge?

In answering these questions we seek to determine whether FERC modeled the full set of factors that are likely to be affected by competition, and to identify lessons that can be learned for choosing the appropriate assumptions regarding these various factors in the future.

5.2 Assumptions Regarding the Effects of Order 888

FERC assumed that the trend toward more competitive wholesale markets had been underway in 1996 for some time and would continue even absent Order 888. However FERC also assumed that Order 888 would accelerate the movement toward competition significantly. FERC modeled increasing competition in the competition scenarios (relative to the base cases) by adjusting five different factors:

- Transmission barriers. FERC included in its model certain costs (referred to as a usage price) to reflect barriers to the use of the transmission grid. FERC assumes that Order 888 lowers barriers to transmission use between 1996 and 2010, thus the usage price falls faster in the competition scenarios than in the base cases.

- Reserve margins. Planning reserve margins are assumed to fall as utilities make greater use of existing power plants and bulk power purchases.

- Fossil plant availability. Availability is assumed to improve as plant owners seek to make the most of existing power plants in a competitive market.

- Heat rates for existing fossil plants. These are assumed to improve as competition leads plant owners to more effectively maintain plants and to reduce fuel costs of existing power plants.
- Heat rates for new gas combined cycle plants. These are assumed to improve as competition leads plant owners to use better technology and to reduce fuel costs for new power plants.

The specific assumptions that FERC used to model each of these factors are summarized in Table 5.1. Assumptions that differ between the base case and the associated competition scenario are presented in italics.

Table 5.1 Modeling Assumptions That Reflect the Impact of Order 888

	Base Cases		Competition Scenarios	
Assumption/Factor	Favoring Gas	Favoring Coal	Competition-Favors-Gas	Competition-Favors-Coal
Coal and Gas Prices	Gas, coal prices maintain same relative position as last 10 years	Gas prices rise as in most forecasts; coal prices fall	Gas, coal prices maintain same relative position as last 10 years	Gas prices rise as in most forecasts, coal prices fall
Transmission Barriers	Usage price gradually falls to 0.5 mill/kWh by 2010	Usage price gradually falls to 0.5 mill/kWh by 2010	*Usage price falls to 0.5 mill/kWh by 2000*	*Usage price falls to 0.5 mill/kWh by 2000*
Competition Reserve Margins	Fall to 15 percent gradually by 2005	Fall to 15 percent gradually by 2005	*Fall to 15 percent by 2000, 13 percent by 2005*	*Fall to 15 percent by 2000, 13 percent by 2005*
Fossil Plant Availability	Rise to 85 percent in 2005	Rise to 85 percent in 2005	Rise to 85 percent in 2005	*Rise to 85 percent in 2000, 90 percent in 2005*
Heat Rates for Existing Fossil Plants	Heat Rates Degrade Over Time	Heat Rates Degrade Over Time	Heat Rates Degrade Over Time	*Heat Rates Do Not Degrade Over Time*
Heat Rates for New Combined Cycle Gas Plants	Heat Rate Set at 7500 Btu/kWh	Heat Rate Set at 7500 Btu/kWh	*Heat Rate Improves to 6800 Btu/kWh*	Heat Rate Set at 7500 Btu/kWh

Source: FERC FEIS, Table ES-1.

Transmission Barriers

FERC assumed the same transmission capacity and capability in all base cases and competition scenarios. FERC assumed that Order 888 would not lead to new transmission line construction during the study period, because Order 888 does not remove the principle barriers to construction of new lines. FERC also assumed that Order 888 would not lead to increased transfer capability of existing transmission lines, because such innovations were too speculative.

However, FERC assumes that some of the barriers to using the existing transmission lines are reduced over time, allowing for greater bulk power transmission across regions.

FERC included in its model a "usage price" to reflect barriers to the use of the transmission grid. The barriers represented by the usage price include line losses, constraints on transmission capacity and transaction costs associated with using a system that was not designed to be the basis of a competitive market. FERC assumes that on-going industry trends would eventually reduce the barriers of transmission usage in the base cases, but that these barriers would be reduced more quickly in the competition scenarios. FERC assumed the same reduction of transmission barriers in both the Competition-Favors-Coal and the Competition-Favors-Gas Scenarios.

Recent experience has been generally consistent with FERC's assumptions regarding the amount of transmission capacity. While there have been some cases of transmission upgrades and expansions in recent years, they have significantly lagged behind both the increase in electricity demand and the increase in generation plant capacity additions. (Hirst 2000)

In fact, since 1982 there has been a clear and steady reduction in the amount of US transmission capacity when normalized by peak demand (i.e., MW-miles of transmission per MW of summer peak). (Hirst 2001) Given that this reduction in normalized transmission capacity has been occurring for so long, and that it has occurred consistently in every region of the US, it is clear that Order 888 is not solely responsible for reduced (or increased) transmission investments. Therefore, FERC's assumption that transmission capacity would remain unchanged between the base cases and the competition scenarios appears to have been supported by recent experience.[6]

FERC's assumptions about reduced transmission barriers may be generally consistent with recent experience, although it is difficult to quantify the extent to which FERC's usage price reflects experience. In December 1999 FERC issued Order 2000, which was designed to advance the formation of Regional Transmission Organizations (RTOs). This order notes that since the adoption of Order 888 "power resources are now acquired over increasingly large regional areas, and interregional transfers of electricity have increased." (FERC 1999, page 13) It also notes that "because of the changes in the structure of the electricity industry, the transmission grid is now being used more intensively and in different ways than in the past." (FERC 1999, page 16)

However, the same order dedicates roughly 38 pages to a discussion of the existing barriers and impediments in the transmission system, and concludes that "economic and engineering inefficiencies and the continuing opportunity for undue discrimination are impeding competitive markets." (FERC 1999, page 70) In fact, FERC uses these barriers and impediments to justify the need for RTOs. So FERC's Order 2000 suggests both (a) that transmission barriers have been reduced in recent years, and (b) that many barriers remain.

6 This is not to say that increased competition would not have an impact on transmission investments. It could lead to concerns about cost recovery of transmission lines, and it could create uncertainty about the amount of profits that could be obtained from new transmission lines. However, recent experience suggests that these factors would be secondary impacts compared to the on-going trends in the industry that have reduced the investments in new transmission lines.

Bottom line: Because of the proxy that FERC used to model transmission barriers, and the lack of data to compare with the proxy, it is difficult to determine just how closely FERC's transmission assumption compares with recent experience. However, broad industry trends suggest that their modeling assumptions were not dramatically different from recent experience. Increased transmission capacity could, in theory, lead to increased generation from regions with plentiful, low-cost, existing coal plants, leading to increased air emissions, but it appears as though FERC's assumptions on this factor are generally consistent with recent experience.

Reserve Margins

In the two base cases, planning reserve margins are assumed to fall gradually from 17 percent in 1996 to 15 percent in 2005 and to remain at 15 percent thereafter. In the two competition scenarios, FERC assumes that reserve margins fall faster and farther – to 15 percent in 2000 and 13 percent in 2005.

Reserve margins in the US have declined steadily since the early 1980s. However, the reductions in recent years have not been as great as FERC had projected. The 2000 reserve margin for the US on average was 17.1 percent – slightly higher than FERC's assumption under both competition scenarios. (NERC 2000) It is quite likely that reserve margins will continue to decline on average, as projected by FERC in both competition scenarios.[7]

In general, lower reserve margins result in construction of less new combined-cycle capacity and increased utilization of existing coal plants. Therefore, lower reserve margins tend to lead to increased air emissions. So if FERC's projection of declining reserve margins under the competition scenarios turned out to be accurate, it would have lead to increased air emissions (all else being equal).

Bottom line: Since FERC slightly overestimated the amount to which reserve margins would decline, its projections slightly overstated the amount of air emissions that would occur in the competition scenarios.

Fossil Plant Availability

In the two base cases, national average plant availability for fossil plants is assumed to increase gradually from 81 percent in 1993 to 85 percent in 2005.[8] In the Competition-Favors-Coal Scenario, plant availabilities rise faster and farther than in the base cases – to

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[7] However, this issue is complicated by the fact that competition could lead to cyclical construction patterns, where merchant power plant developers build large amounts of capacity in response to periods of low reserve margins and high electricity prices. Once this capacity comes on line, the reserve margin increases, electricity prices decline, and developers stop building power plants for a while. Then the reserve margins drop and the cycle begins again. This inability to maintain an optimal balance of supply and demand results from the fact that new power plants take three to four years to plan for, get permitted, construct and bring on-line.

[8] A power plant's availability factor indicates the percent of time within a year that the plant is available for service.

85 percent in 2000 and 90 percent in 2005.[9] FERC assumes this only for the Competition-Favors-Coal Scenario, because, due to the large installed base of coal-fired plants, a general increase in all plant availability will favor coal.

Fossil plant availability factors have not risen as dramatically as FERC assumed under the Competition-Favors-Coal Scenario. Equivalent availability factors increased steadily to a peak of 83.9 percent in 1997, but dropped slightly in 1998 (83.3 percent) and 1999 (82.4 percent).[10] (NERC 2000) Therefore, the industry is likely to fall slightly short of the 85 percent target of the Competition-Favors-Coal Scenario. However, it is possible that fossil plant availability factors could continue to increase to the 85 percent target by 2005, as assumed in the base cases.

Fossil plant availability factors have risen steadily from at least 1982 through 1997. Therefore any improvements to availability are most likely due to industry trends, and cannot be attributed to Order 888 or increased competition in general.

FERC assumptions slightly overstate the availability of fossil power plants in the Competition-Favors-Coal Scenario – at least in the short term and probably in the long-term as well. They also overstate the effect that Order 888 is likely to have on fossil plant availability, by suggesting that the improvement would occur under competition but not in the base cases. FERC's assumptions, therefore, will lead to an overstatement of coal generation in the Competition-Favors-Coal Scenario, which will lead to an increase in air emissions (all else being equal).

Bottom line: FERC's assumption on fossil plant availability overstates the amount of air emissions in the Competition-Favors-Coal Scenario, and therefore overstates the impact that Order 888 is likely to have on air emissions.

Power Plant Heat Rates

Finally, FERC makes some assumptions regarding the impact of competition on power plant efficiencies, or "heat rates."[11] Both base cases assume that each existing plant's heat rate increases over time (the plant becomes less efficient) until the plant is retired or undergoes a life extension project. Heat rates for *new* combined-cycle gas plants are assumed to remain at the 1996 level (7,500 Btu/kWh) through 2010, in both base cases.

The Competition-Favors-Coal and Competition-Favors-Gas Scenarios make different assumptions about heat rates. The Competition-Favors-Coal Scenario assumes that heat rates for new combined-cycle plants remain at 7,500 Btu/kWh, and that heat rates for existing coal plants will not degrade throughout the study period due to improvements in coal plant maintenance. The Competition-Favors-Gas Scenario assumes no change in

[9] FERC notes that "some older coal plants are not likely to reach this level without substantial capital investment." However, FERC selected this figure believing that it illustrates an upper bound of what existing coal plants could achieve if the industry focused on meeting competition through increased use of existing coal-fired plants (FEIS page. 3-18).

[10] Plant availability data were not available for 2000 at the time this report was prepared.

[11] Heat rate is a measure of a plant's efficiency. It is usually stated in terms of the energy (Btu) needed to produce one kWh of electricity, or Btu/kWh.

coal plant heat rates and assumes that new combined-cycle plants achieve a heat rate of 6,800 Btu/kWh.

Heat rates for new combined cycle plants have declined steadily in recent years. The Energy Information Administration currently assumes that combined cycle power plants installed in 2000 can achieve a heat rate of 6,927 Btu/kWh, and that plants installed in 2010 will be able to achieve even lower heat rates of 6,350 Btu/kWh. (EIA 2000)

If existing fossil plants can improve (or avoid degradation of) heat rates over time, then they will consume less fuel per kWh and therefore produce less air emissions per kWh. However, they will also be more economically competitive relative to other power plants that might have lower emission rates, which would lead to higher air emissions (all else being equal).

If new natural gas combined cycle plants can improve heat rates over time, they will be more economically competitive than other existing fossil plants, and they will consume less fuel per kWh, both of which will produce less air emissions (all else being equal).

Bottom line: With regard to new combined cycle plant heat rates, FERC's assumptions are too high in the Competition-Favors-Coal Scenario, and fairly close in the Competition-Favors-Gas Scenario. Consequently, FERC's heat rate assumptions lead to overstated air emissions from the Competition-Favors-Coal Scenario.

Overall Impact of These Assumptions

FERC's modeling assumptions under the Competition-Favors-Coal Scenario turned out to be fairly close to actual experience in recent years. The slight deviations between FERC's assumptions and actual experience are likely to lead to overstatement of air emissions in most cases, as summarized below:

- With regard to transmission barriers, it appears as though FERC's assumptions are not significantly different from recent experience, and any difference could have lead to increased or decreased air emissions. We expect that supply, demand, and power plant economics across the regions play a larger role in determining transmission levels than do the transmission barriers modeled by FERC.

- With regard to reserve margins, FERC slightly overestimated the amount to which reserve margins would decline, and therefore slightly overstated the amount of air emissions that would occur.

- With regard to fossil plant availability, FERC slightly overstates existing fossil availability and therefore overstates the amount of air emissions in the Competition-Favors-Coal Scenario.

- With regard to combined cycle plant heat rates, FERC's heat rate assumptions are too high in the Competition-Favors-Coal Scenario, leading to overstated air emissions in that scenario.

Nevertheless, our analysis in Chapter 4 above indicates that FERC underestimated the 2000 CO_2 emissions in the Competition-Favors-Coal Scenario by roughly seven percent.

This underestimation is apparently not explained by the four factors discussed above. Other modeling assumptions used in FERC's analysis are apparently responsible for a large portion of this underestimation, as described in the following section.

5.3 Assumptions That Remain Constant in All Scenarios

FERC assumed that numerous factors affecting the electricity industry would remain unchanged between the base cases and the competition scenarios. Table 5.2 presents a summary of these inputs. Some of these factors could have a large impact on the air emissions from the electricity industry – even if they turn out to be the same in all cases and scenarios – and could explain some of the deviation between FERC's air emission projections and those actually experienced in 2000.

Table 5.2 Modeling Assumptions that Remain Constant In All Cases and Scenarios

Input	Assumption
US Electricity Load Growth	1995 – 2000: 1.8% per year 2000 – 2010: 1.7% per year
Power Plant Lifetimes	Coal and Oil Steam: -- 60 years if > 50 MW -- 45 years if < 50 MW Gas Steam: 45 years Nuclear: 40 years Turbines: 20 years
U.S. Nuclear Capacity	2000: 98 GW 2005: 98 GW 2010: 92 GW
Nuclear Capacity Factors	1995 – 2010: 74%
U.S. Hydro Capacity	2000: 86.0 GW 2005: 86.1 GW 2010: 86.1 GW
World Oil Prices (1995 $)	1995: 18.69 $/BBL 2000: 19.86 $/BBL 2005: 22.32 $/BBL 2010: 25.04 $/BBL
Environmental Regulations	Title IV of CAAA of 1990 is implemented (FERC assumes no NOx controls are installed on Group II boilers). Phase II of the OTC MOU is implemented.

Furthermore, it is possible that some of the factors listed in Table 5.2 might be affected by Order 888. If this were the case, then FERC's modeling approach would not capture some important impacts of the Order. In the sections below we look at three key modeling factors – load growth, power plant lifetimes and nuclear capacity factors – and assess (a) the extent to which FERC's assumptions were consistent with recent experience, and (b) whether the factor might be affected by Order 888. The results can help guide future forecasting efforts of a competitive electricity market by further refining the choice of assumptions.

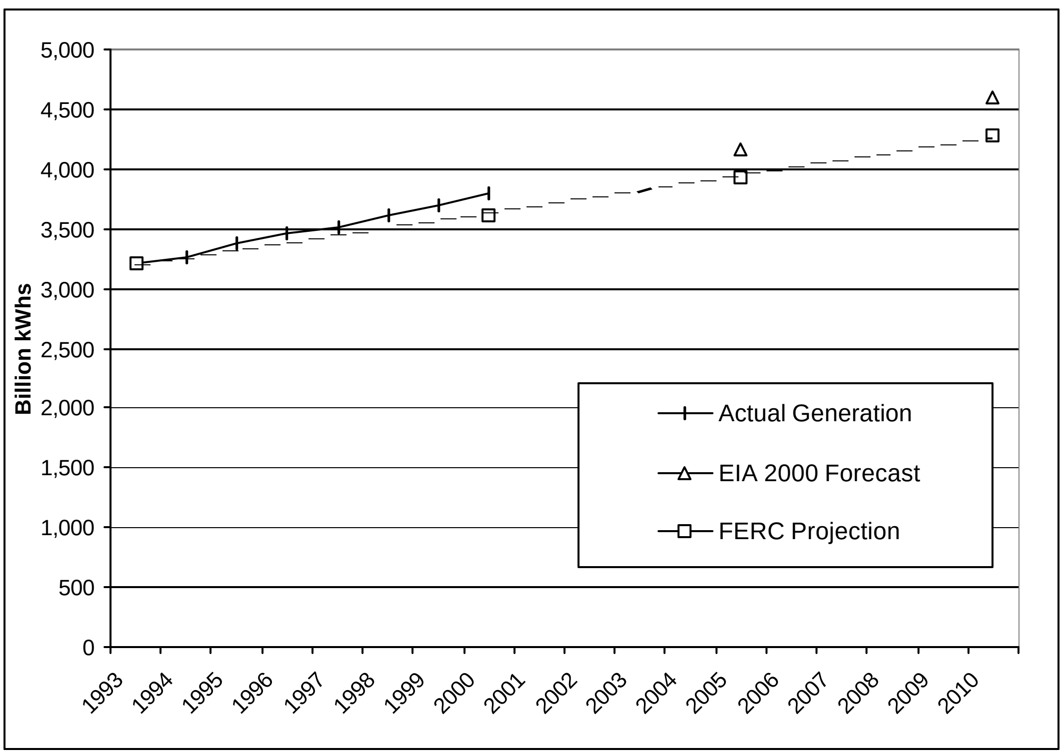
Electricity Generation

As indicated in Figure 5.2, FERC's assumption for US electricity generation in 2000 turned out to be lower than actual generation in that year. Actual US electricity generation in 2000 was 3,792 TWh, and FERC's projection was 3,617 TWh – roughly 4.6 percent lower.

FERC's underestimate of electricity generation has important ramifications for FERC's air emissions projections, because additional generation from fossil power plants, particularly coal, will lead to higher air emissions. While some pollutants can be controlled, CO_2 emissions per MWh of generation are determined by fuel type and heat rate. Thus electricity generation is the most important factor determining CO_2 emissions, together with the mix of plant types and heat rates.

Furthermore, as indicated in Figure 5.2, current projections of US electricity generation indicate that FERC's projection will continue to be low throughout the study period. By 2010, FERC's projection of US electricity generation could be too low by as much as seven percent. This would likely result in a significant underestimation of the air emissions in the later years.

Figure 5.2 US Electricity Generation: FERC Projections Compared with Actual Generation From 1993 to 2000 and Current Projections for Later Years



Given the importance of electricity generation in determining air emissions, it is important to consider whether Order 888 itself was likely to have an impact on electricity generation. At the time the FEIS was prepared, some studies warned of the potential for increased competition in the electricity industry to increase electricity sales and therefore increase air emissions. (Tellus Institute 1995) Several reasons were given:

- If increased competition were to achieve its intended goal of lowering electricity prices, then customers could be expected to increase their level of electricity consumption in response.
- Retail electricity providers can be expected to promote increased electricity sales as a conventional strategic objective for maximizing profits. Electricity sales could be promoted through declining block rates, fuel-switching to electricity, or offers of low-cost electricity as means of gaining customer acceptance or tying electricity sales to other products.
- Distribution companies can be expected to promote increased sales in response to price caps that would be established during restructuring proceedings and utility merger agreements.
- Vertically-integrated electric utilities could reduce or eliminate their demand-side management (DSM) activities due to concerns about creating stranded costs and other uncertainties in a restructured electricity market.

It is difficult to determine the impact that increased competition has had on electricity sales, due to the limited experience with retail competition to date. The one exception is the prediction that DSM activities would be reduced in response to electricity restructuring. Utility DSM expenditures were cut dramatically from $2.4 billion in 1995 to $1.4 billion in 1999. (EIA 1999) It is clear that these reductions are due to uncertainties and risks created by industry restructuring, and in some cases by just the *expectation* of industry restructuring in the future.

It is important to note that other factors potentially unrelated to restructuring may have been responsible for much of the higher electricity load growth experienced from 1993 through 2000. Much of the increase in load growth was due to the rapid economic expansion of the latter half of the 1990s.[12] Nonetheless, the rapid load growth during this period could have been significantly moderated by utility DSM activities, had they been increased rather than decreased during this period. Energy efficiency initiatives are most cost-effective, and efficiency savings are most easily achieved, during times of rapid economic expansion when new end-use equipment is purchased and new buildings are constructed.

[12] We performed a linear regression to test the correlation between electricity sales growth and GDP growth. The regression analysis included 1993-2000 US electricity sales as the dependent variable and US GDP growth rates and relative US electricity prices as the explanatory variables. Both explanatory variables were statistically significant, and the regression had a high adjusted R-squared of 90 percent, indicating that GDP and price were responsible for 90 percent of the variation in US electricity sales over this period.

Clearly, there is enough uncertainty about the impact of increased competition on electricity load growth that it is tenuous to assume this factor will remain unchanged in competition scenarios. Furthermore, while it may be too soon to identify increased load growth as a result of increased competition by 2000, this effect could easily become much larger over the long-term. A more thorough investigation of the environmental impact of competitive electricity markets should include electricity load growth as one of the factors that change in the competition scenarios. This approach can help indicate the potential for greater air emissions from the electricity industry over the long-term future.

Bottom line: Electricity load growth is one of the most important factors driving air emissions from the electricity industry, and could easily be affected by increased competition. This should be included as one of the factors that change in competition scenarios, and if done so will likely project greater air emissions.

Coal Plant Lifetimes

FERC notes that there is considerable uncertainty over the lifetimes of existing fossil capacity. However it also notes that the relatively low cost of keeping these plants in operation, coupled with the absence of current (1996) plans to retire significant capacity, indicates that these plants are likely to be available in the foreseeable future. Where companies have announced plant retirements (by early 1996), FERC assumes the plant will retire in that date. Where no retirement has been announced, a 60-year lifetime is assumed for units larger than 50 MW and a 45-year lifetime, for units smaller than 50 MW.

Coal plants can be expected to have longer operating lives under competitive electricity markets than under regulated markets. Recent sales of existing coal power plants indicate that they are considered very valuable in the current and future electricity market. Coal plants that have already been sited, have all the necessary transmission access, have already incurred the large costs of construction, and have relatively low operating costs will prove to be valuable for a long time and are unlikely to be retired any earlier than necessary. Many coal plants could easily operate longer than the 60-year lifetime that FERC assumed in the FEIS.

Furthermore, increased competition in the electricity industry could create incentives for power plant owners to operate their power plants longer than utilities would have in a regulated environment. Existing coal plants with low operating costs can become more profitable in a competitive electricity market, and independent power plant owners have less regulatory certainty about cost recovery so they may be more inclined to hold onto existing power plants than regulated utilities would.

If FERC had assumed that coal plants will have longer operating lives under increased competition, it would have found that competition could lead to increased air emissions (all else being equal). There would probably be a small effect from this change by 2000, as not many of the US coal plants are assumed to retire by then, but the effect could be significantly larger in later years.

Bottom line: FERC's methodology for not changing coal plant lifetimes under competitive scenarios does not capture the full effect of Order 888, and is likely to lead to an underestimate of air emissions, particularly over the long-term. This should be taken into account in future analyses of competitive electricity markets.

Nuclear Plant Lifetimes and Capacity Factors

FERC assumes that total nuclear-powered electric generating capacity remains roughly at 1996 levels through 2010, with a small increase by 2000 reflecting the completion of two Tennessee Valley Authority units. FERC assumes that, after 2005, nuclear units are shut down at the end of their 40-year license period. FERC notes that this assumption is conservative in terms of air emissions, i.e., it will overstate industry air emissions relative to a scenario in which nuclear plants are relicensed. FERC also assumes that average nuclear capacity factors remain steady through 2010 at the 1996 level of 74 percent. This is a similarly conservative assumption, as improving nuclear capacity factors would reduce industry air emissions.

Increased competition in the electricity industry is likely to create incentives for nuclear plant owners to operate their power plants at higher capacity factors and for longer lifetimes than utilities would in a regulated environment. Recent sales of nuclear power plants indicate that many of them are considered very valuable in the current and future electricity market. Nuclear plants that have already been sited, have all the necessary transmission access, have already incurred the large costs of construction, and have relatively low operating costs will prove to be valuable for a long time and are unlikely to be retired any earlier than necessary. Four nuclear power plant units have already received approvals for extending their operating licenses. We expect that this is the beginning of a national trend, and that many nuclear plants will obtain license extensions and operate well beyond 40 years. Also, recent experience suggests that ownership of nuclear plants will become more concentrated in a competitive market, and the few remaining owners are more likely to have the expertise and ability to operate their nuclear plants at higher capacity factors and for longer lifetimes.

In fact, nuclear capacity factors have been increasing steadily in recent years, as indicated in Table 4.1 above. From 1993 to 2000 the US nuclear fleet average capacity factor increased from 70.3 percent to an impressive 89.8 percent. So nuclear generation has been, and will likely continue to be, substantially higher than the 74 percent assumed by FERC in the FEIS.[13] It is questionable whether the industry will be able to sustain such a high capacity factor over the long-term, given the need for extensive maintenance and upgrades of nuclear plants. Nonetheless, it is clear that nuclear capacity factors have been rising steadily and are likely to remain somewhat higher than FERC's assumption.

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[13] Given that FERC's projections for nuclear generation were significantly lower than actual nuclear generation, one would expect that this would lead FERC to overestimate CO_2 emissions. However, the opposite is true. In addition to the higher load growth discussed above, two other factors offset FERC's low projection of nuclear generation. First, FERC's projection of 2000 hydro generation was significantly higher than actual experience in that year, as discussed in Section 4.1. Second, the unexpectedly rapid growth of load and generation apparently required the increased use of older, less efficient fossil plants, which lead to higher emissions of CO_2 per unit of electricity produced.

If FERC had assumed that nuclear plant capacity factors would be higher and lifetimes would be longer under increased competition, it would have found that competition would lead to lower air emissions (all else being equal), as the existing nuclear plants operate more frequently and displace more fossil plants. The higher capacity factor assumption could have a significant effect by 2000, given the recent experience with high capacity factors. The increased lifespan assumption would have little effect by 2000, as not many plants reach the end of their operating licenses by then, but would have a more significant effect in later years.

Since FERC did not anticipate the increase in nuclear generation caused by electric industry competition, the FEIS did not fully recognize that competition can lead to increased environmental impacts from nuclear power. While an increased level of nuclear generation can lead to lower emissions of conventional air pollutants, it will also lead to greater amounts of spent nuclear fuel, as well as greater amounts of radionuclide emissions that occur during fuel mining, plant operations, and fuel disposal.

Bottom line: FERC's methodology for not changing nuclear plant capacity factors and lifetimes under competitive scenarios does not capture the full effect of Order 888, and is likely to lead to an overestimate of air emissions, particularly over the long-term. However, FERC's approach understates the potential for increased environmental impacts of nuclear power in other areas as a consequence of Order 888. Future analyses of the environmental impacts from a more competitive electricity market should include a more robust nuclear generation sector as part of their future scenarios.

Overall Impact of These Assumptions

The most important conclusion from the preceding analysis is that FERC's modeling methodology was too narrowly defined to fully capture the effects of Order 888 and increased competition in the electricity industry. Different assumptions regarding load growth, power plant lifetimes and nuclear capacity factors in competition scenarios can clearly lead to different environmental effects in assessments of future competitive electricity markets.

We are unable to quantify and untangle the effect each of these changes would have on FERC's results. Some effects (underestimating load growth and coal plant lifetimes) tend to produce underestimates of air emissions, while others (underestimating nuclear plant capacity factors and lifetimes) tend to produce overestimates of air emissions. However, our analysis in Section 4 suggests that electricity load growth plays a large role in the production of air emissions, and is probably the dominant factor explaining why FERC underestimated the NO_X and CO_2 emissions in 2000.

6. Conclusions

It is difficult to fully assess the accuracy of FERC's predictions for 2000 and beyond, given that some parts of the country have not experienced much electricity industry competition yet, and those that have been exposed to competition have not had many years of experience with it. Nevertheless, several general conclusions can be drawn from the experience of the recent past.

- Natural gas prices have been relatively high and coal prices have remained relatively low since the FEIS was prepared. Consequently, FERC's Competition-Favors-Coal Scenario most accurately represents recent industry experience, as well as the most likely future. This Scenario indicates that increased competition at this time is more likely to lead to increased air emissions than decreased emissions – absent additional actions to reduce the environmental impacts of electricity generation and consumption.
- FERC's projections of national NO_X and CO_2 emissions in 2000 were lower than actual experience. In the Competition-Favors-Coal Scenario, FERC's forecast of NO_X emissions was roughly four percent lower than actual experience, and its forecast of CO_2 emissions was roughly eight percent lower. While we did not analyze mercury emissions in 2000, it is likely that the FEIS projections underestimated these emissions as well because the FEIS underestimated coal generation.
- FERC's projection of national electricity demand through 2000 was lower than actual experience, by 4.6 percent. This is the dominant factor explaining why FERC's projections of NO_X and CO_2 emissions were lower than actual experience. A more thorough investigation of the environmental impacts of competition should assess the potential for competition to increase electricity demand, and the extent to which increased demand would lead to increased air emissions. Such an assessment should consider the effect that competition has on utility DSM programs, and their impact on electricity demand.
- FERC assumed that a number of electricity industry factors would remain unaffected by competition. It is quite likely that some of these factors – in particular electricity demand, nuclear generation, and nuclear and coal plant lifetimes – *would* be affected by increased competition. In other words, FERC's assumptions regarding the likely changes due to Order 888 were too narrowly defined. Future analyses of the environmental impacts of electricity competition should consider these factors in more depth.
- Of those electricity industry factors that were assumed to be affected by competition, FERC's assumptions under the Competition-Favors-Coal Scenario turned out to be fairly close to actual experience in recent years. The slight deviations between FERC's assumptions and actual experience are likely to lead to increased air emissions in most cases.

- Coal-fired power plants in the Midwest and South do not appear to have increased generation in order to export power into other regions in response to Order 888. While coal generation has increased considerably in the Midwest and South Atlantic regions, this increased generation was needed to meet load growth within each region. Nonetheless, while electricity exports did not increase, air pollution did, which was the chief concern of those expressing fears of greater exports from regions dominated by relatively less-controlled coal power plants.
- The FERC underestimate of CO_2 emissions was greater than the underestimate of generation growth, indicating a more carbon-intensive generation mix than originally projected. This has important implications for climate change policies.

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Appendix A. Adjustments to FERC Numbers

In comparing the FEIS's projections for the year 2000 to actual data for 1995 through 2000 we encounter two problems. First, the Energy Information Administration (EIA) routinely revises numbers published in previous years, based on ongoing quality assessment and new data. FERC used as its base year data the most recent numbers available (in 1995) for generation and emissions – 1993 numbers. However EIA revised these numbers after FERC published the FEIS. Thus, some of the numbers EIA now publishes for 1993 are different from those in the FEIS. Where EIA has revised 1993 data, we have used the revised number, as if this number had been published in the FEIS.

A second and more significant problem comes with the generation and capacity categories that FERC used. FERC modeled generation and capacity in the following categories: coal, nuclear, oil/gas, hydro, geothermal, other and non-utility.[14] The non-utility category includes data on plants not owned by utilities. This distinction becomes problematic for this analysis, because many power plants have changed their status (i.e., gone from utility ownership to non-utility ownership) since 1995. If we were to preserve this distinction, the effects of plants switching status would confound our analysis of changes in generation, capacity and emissions from one year to anther.

To remedy this problem, we have used EIA data on utility and non-utility generation and capacity to allocate the non-utility generation and capacity shown in the FEIS into the appropriate fuel category for the years 1993 and 2000.[15] We have used EPA emission factors to revise FERC's emissions projections for 2000 consistent with the changes made to the 2000 generation numbers. All changes we have made are shown in the tables below. The revisions that EIA made to 1993 data can be seen by comparing the columns labeled "FEIS" and "EIA Utility." The adjustments we have made to the FEIS numbers for 1993 and 2000 are shown in the columns labeled "Adjustment."

The adjustments presented in the following tables were made for both the 1993 and the 2000 FERC data. We are able to make the same adjustment to both years because the FEIS assumes very little change in non-utility generation from 1993 to 2000. All of the FEIS changes in capacity, generation and emissions are included in the other fuel categories.

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[14] Note that by projecting oil- and gas-fired data in the same category FERC makes it impossible to discern what their predictions are for each of these fuels separately. This is a significant shortcoming of the CEUM model in this application, as nearly all new capacity is expected to be gas-fired.

[15] Note that the figures for 1993 non-utility generation and capacity in the EIS are lower than EIA's 1993 non-utility numbers due to EIA revisions. This means that the process of allocating non-utility figures into fuel categories and regions is not a zero-sum process. The 1993 numbers and 2000 projections in the EIS have been adjusted upward from the original values. The difference between the 1993 and 2000 numbers in the EIS, however, remains the same.

Table A.1 Adjustments to 1993 and 2000 FERC Capacity Data (GW)

Plant Type	FEIS	EIA Utility	EIA Non-Utility	EIA Total	Adjustment
Coal	301	301	10	311	10
Nuclear	99	99	0	99	0
Oil/Gas	202	202	34	236	34
Hydro	96	96	3	99	3
Geothermal/Other	2	2	14	16	14
Non-Utility	28	0	0	0	-28
Total	728	700	61	761	33

Table A.2 Adjustments to 1993 and 2000 FERC Generation Data (billion kWh)

Plant Type	FEIS	EIA Utility	EIA Non Utility	EIA Total	Adjustment
Coal	1,639	1,639	53	1,693	54
Nuclear	610	610	3	614	4
Oil/Gas	349	358	188	546	197
Hydro	264	265	12	277	13
Geothermal/Other	10	10	69	79	69
Non-Utility	179	0	0	0	-179
Total	3,051	2,883	325	3,208	157

Table A.3 Adjustments to 1993 and 2000 FERC Capacity Data (billion kWh)

Census Region	FEIS	EIA Utility	EIA Non-Utility	EIA Total	Adjustment
New England	24	22	5	27	3
Middle Atlantic	87	80	9	89	2
South Atlantic	141	135	10	145	4
East North Central	115	114	6	120	5
East South Central	59	59	2	61	2
West North Central	55	55	1	56	1
West South Central	106	103	13	116	10
Mountain	51	50	2	52	1
Pacific	86	82	13	95	9
Total	724	700	61	761	37

Table A.4 Adjustments to 1993 and 2000 FERC Generation Data (billion kWh)

Census Region	FEIS	EIA Utility	EIA Non-Utility	EIA Total	Adjustment
New England	102	84	28	112	10
Middle Atlantic	342	307	49	356	14
South Atlantic	595	575	44	619	24
East North Central	524	514	26	540	16
East South Central	274	274	11	285	11
West North Central	219	218	5	223	4
West South Central	426	394	80	474	48
Mountain	263	255	9	264	1
Pacific	305	261	73	334	29
Total	3,050	2,882	325	3,207	157

Table A.5 Adjustments to 1993 and 2000 FERC NOx Emissions (thousand tons)

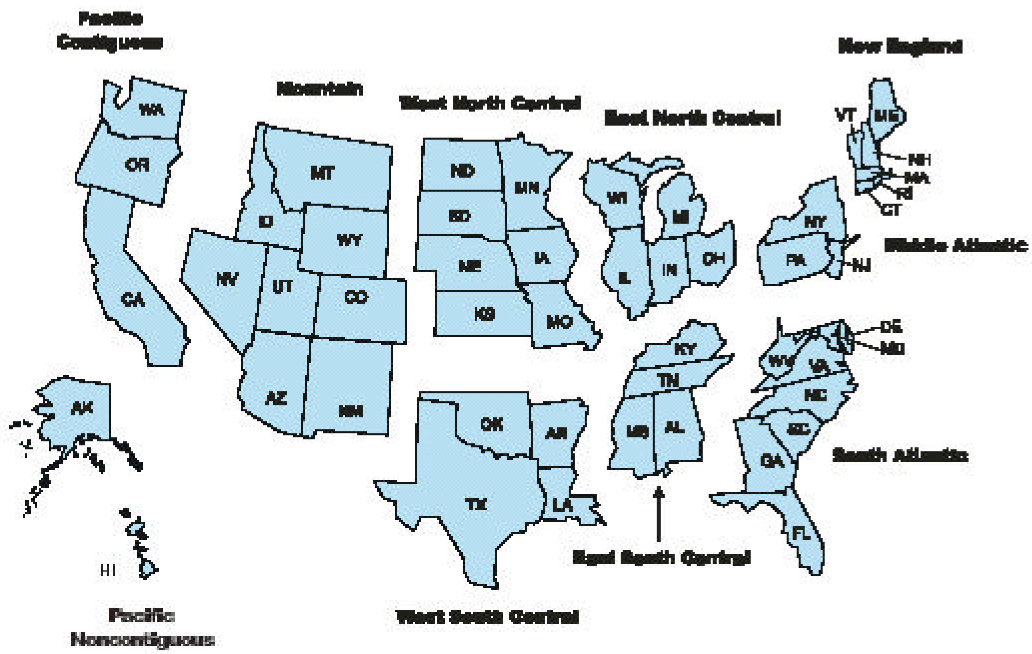
Census Region	FEIS	EIA Utility	EIA Non-Utility	EIA Total	Adjustment
New England	74	84	32	115	41
Middle Atlantic	406	501	84	585	179
South Atlantic	1,038	1,258	91	1,349	311
East North Central	1,463	1,828	10	1,838	375
East South Central	689	842	133	975	286
West North Central	657	853	23	876	219
West South Central	877	1,063	122	1,185	308
Mountain	520	764	20	783	263
Pacific	120	140	72	213	93
Total	5,844	7,332	587	7,919	2,075

Table A.6 Adjustments to 1993 and 2000 FERC CO_2 Emissions (million tons)

Census Region	FEIS	EIA Utility	EIA Non-Utility	EIA Total	Adjustment
New England	32	31	15	46	14
Middle Atlantic	163	161	32	193	30
South Atlantic	382	379	18	397	15
East North Central	398	393	4	397	-1
East South Central	225	223	35	258	33
West North Central	192	190	4	194	2
West South Central	302	299	48	347	45
Mountain	206	204	5	209	3
Pacific	43	47	34	81	38
Total	1,943	1,927	196	2,123	180

Appendix B. Map of US Census Regions

Figure A1. Census Divisions



Source: Energy Information Administration.