Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges

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EXECUTIVE SUMMARY

Over the past several years, a number of groups have questioned whether implementation of coordinated wholesale electricity markets in several regions of the United States has benefited retail electricity customers. The development of these markets was motivated in large part by a desire to achieve increased short-term and long-term efficiency in the generation and delivery of electricity through increased reliance on market mechanisms. Along with this came the expectation of lower retail electricity prices, similar to what occurred in other industries that have undergone a deregulation, such as long-distance telephone service, passenger airlines, and interstate trucking. Spurred by recent increases in electricity prices, some groups have called for a re-examination of the deregulated market structure adopted in coordinated markets in the Midwest, Mid-Atlantic and Northeast (i.e., LMP pricing, day-ahead markets based on security-constrained unit commitment, and financial transmission rights). Some critics have even called for a return to the previous system of rate of return regulation and control area operation by vertically integrated utilities.

This paper provides an empirical analysis demonstrating that the implementation of coordinated markets has served to reduce the increase in average consumer rates that has resulted from increases in input costs for electricity generation. In addressing this policy question the issue is not whether average consumer rates have risen or declined in recent years, but whether they are lower than they would have been absent implementation of coordinated markets. In fact, average electricity rates have risen over the period since the implementation of coordinated markets, but this increase has occurred in all regions of the country as a result of increasing fuel prices, regardless of market structure.

While electricity rates have increased since LMP-based coordinated markets were first implemented in PJM in 1998, the study finds that the average rates of public utilities have risen less than they would otherwise have in both the gas dependent and non-gas dependent regions of the NYISO and PJM. The estimated reductions in average rates resulting from implementation of coordinated markets in the mid-Atlantic region over the 1998-2004 period range from $.50 to $1.80 per megawatt hour. For total PJM and NYISO average load of around 100,000 MW per hour, a rate reduction impact of $.50/MWh projects to $1.2 million per day and $430 million in total savings over a year, while estimated rate reductions of $1.5/MWh found in several models project to total savings of around $1.3 billion per year.

The total savings implied by this study are very large because the savings occur for every megawatt consumed in every hour for the regions studied. Moreover, because the study methodology accounts for the expense of operating RTOs, the estimated cost savings are net of the costs of operating the RTOs implying cumulative consumer savings from the implementation of coordinated markets in the PJM and NYISO regions in the billions of dollars for the period through the end of 2004.

The study identifies the impact of the implementation of market coordination on the average residential rates of a large set of municipal and cooperative utilities in PJM and the NYISO, relative to the average rates that would have prevailed in the absence of market coordination. The study controls for a variety of factors that affect retail electricity prices, such as market structure, historic fuel mix and retail access. The study methodology also controls for the impact on average rates of changes in underlying economic factors such as fuel prices, and utility size to provide an "apples to apples" comparison of the retail market prices of utilities operating in regions with coordinated electricity markets to those of utilities operating in regions with a traditional regulatory framework.

The average consumer rates analyzed in this study reflect all market costs borne by the public utilities – energy, ancillary services, capacity market, etc. – all charges for RTO cost recovery as well as the bulk of FERC operating costs, which are recovered through charges imposed on RTOs and their customers. Importantly, the estimated rate savings are the benefits of RTO operation, net of RTO operating costs. While there is a range of estimates of coordinated market impacts, even the lower end of the range of estimated impacts imply very large net benefits.

We believe that this analysis, which reinforces the conclusions of other studies comparing prices in regulated and non-regulated areas, adds to the body of evidence demonstrating the benefits of wholesale competitive markets. It will sharpen the discussion of the merits of wholesale electricity market deregulation and implementation of regional wholesale markets based on LMP pricing. There is a need to progress beyond a simplistic focus on the percentage change in average electricity rates that does not take into account underlying factors that have changed over time in all regions, such as increases in fuel prices.

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I. INTRODUCTION

Over the past several years a number of groups have questioned whether implementation of coordinated electricity markets in several regions of the United States has benefited retail electricity customers. The development of these markets was motivated in large part by a desire to achieve increased short-term and long-term efficiency in the generation and delivery of electricity through increased reliance on market mechanisms. Along with this came the expectation of lower retail electricity prices, as lower prices have been the result in other industries that have undergone deregulation, such as long-distance telephone service, passenger airlines, and interstate trucking. Spurred by recent increases in electricity prices, some groups have called for a re-examination of the deregulated market structure adopted in coordinated markets in the Midwest, Mid-Atlantic and Northeast (i.e., LMP pricing, day-ahead markets based on security-constrained unit commitment, and financial transmission rights) and, even further, for a return to the previous system of rate of return regulation and control area operation by vertically integrated utilities.

This paper provides an empirical analysis of whether implementation of coordinated markets has served to reduce the increase in average consumer rates that has resulted from increases in input costs for electricity generation. In addressing this policy question the issue is

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not whether retail rates have risen or declined in recent years, but whether they are lower than they would have been absent implementation of coordinated markets. Electricity prices, like airfares and trucking rates depend on factors other than regulatory policies and changes in market forces such as fuel prices can, in the short run, mask the impact of deregulation. In fact, average electricity rates have risen over the period since the implementation of coordinated markets, but this increase has occurred in all regions of the country as a result of increasing fuel prices, regardless of market structure.

The objective of this study is to assess whether average retail electricity rates are higher or lower than they otherwise would have been in areas in which coordinated markets have been in operation for several years. In order to address this question we have undertaken an econometric study of the average residential rates of a large and diverse cross-section of utilities for the period 1990-2004. The study controls for a variety of factors that affect retail electricity prices, such as market structure, historic fuel mix and utility size in order to provide an "apples to apples" comparison of the retail market prices of utilities operating in regions with coordinated electricity markets to those of utilities operating in regions with a traditional regulatory framework. The scope of the study is limited for methodological reasons to the analysis of the average residential rates of public utilities but its findings should apply to consumer rates in general, including those of commercial and industrial customers and the customers of investor owned utilities. The study results indicate that, net of RTO operating costs, the establishment of coordinated markets in PJM and the NYISO has enabled annual retail consumer savings of billions of dollars.

Through the use of fifteen years of data covering the period 1990-2004, the study identifies the impact of the implementation of market coordination on the average residential rates of a large set of municipal and cooperative utilities in PJM and the NYISO, relative to the rates that would have prevailed in the absence of market coordination. This is accomplished by including in the study utilities in the Southeast that did not experience the same change in market structure, i.e., utilities that operated within a traditional regulatory framework during the entire period of the study. This enables the statistical analysis to distinguish the impact on average consumer rates of implementing LMP-based coordinated markets from the impact of rising oil and gas prices and other broad market factors.

The study further controls for the effect of changing fuel prices and other exogenous cost changes on utility rates by analyzing the average residential rates over the period 1990-2004 of utilities located both in regions that implemented coordinated markets and in regions that did not. Rising fuel prices affected the average rates of all utilities in the sample, while only some of the utilities in the sample are located in regions that have made the transition to a coordinated market structure. The historical relationship between average retail prices in the mid-Atlantic and Southeast regions is used to project what prices would otherwise have been for utilities located in the regions that implemented coordinated markets, given the actual prices in traditional market regions over the period 1998-2004.

A second factor affecting average residential electricity rates that the study has sought to distinguish from the impact of the implementation of coordinated markets is regional differences in the historic degree of dependence on oil- and gas-fired generation.[2] This has been addressed by conducting separate analyses of rate trends in states with historically high levels of dependence on oil- and gas-fired generation (New York, New Jersey, Delaware, Eastern Maryland[3] and Florida) and in states with low levels of dependence on oil- and gas-fired generation (Pennsylvania, West Virginia, North Carolina, South Carolina, Georgia, Alabama and Arkansas).

A third factor that the study has sought to hold constant, i.e., to distinguish from the impact of wholesale market coordination, is the effect of retail access programs on consumer rates. The regions that were the first to implement coordinated wholesale power markets implemented state retail access programs within essentially the same time frame in which coordinated markets were implemented. Because most of these retail access programs have tended to be associated with less forward hedging of power prices, there is a potential for retail price differences to arise both from the implementation of coordinated wholesale markets and from these unrelated changes in forward hedging. This study has separated these effects by focusing the analysis on the retail rates of municipal and cooperative utilities that have largely not been subject to retail access programs and have retained the obligation to serve.

While average electricity rates have increased since LMP-based coordinated markets were first implemented in PJM in 1998, the study finds that average electricity rates have risen less than they would otherwise have in both the gas dependent and non-gas dependent regions of the NYISO and PJM that have implemented LMP based coordinated markets. Rather than estimating a single statistical model in this study, several different models have been estimated in order to assess the sensitivity of the results to the model structure. All of the models yield estimates of average residential rate reductions arising from implementation of coordinated markets of $.50 per megawatt hour or more; several models yield estimated savings in excess of $1.80 per megawatt hour, while a number produced estimated savings in the range of $1.50 per megawatt hour.

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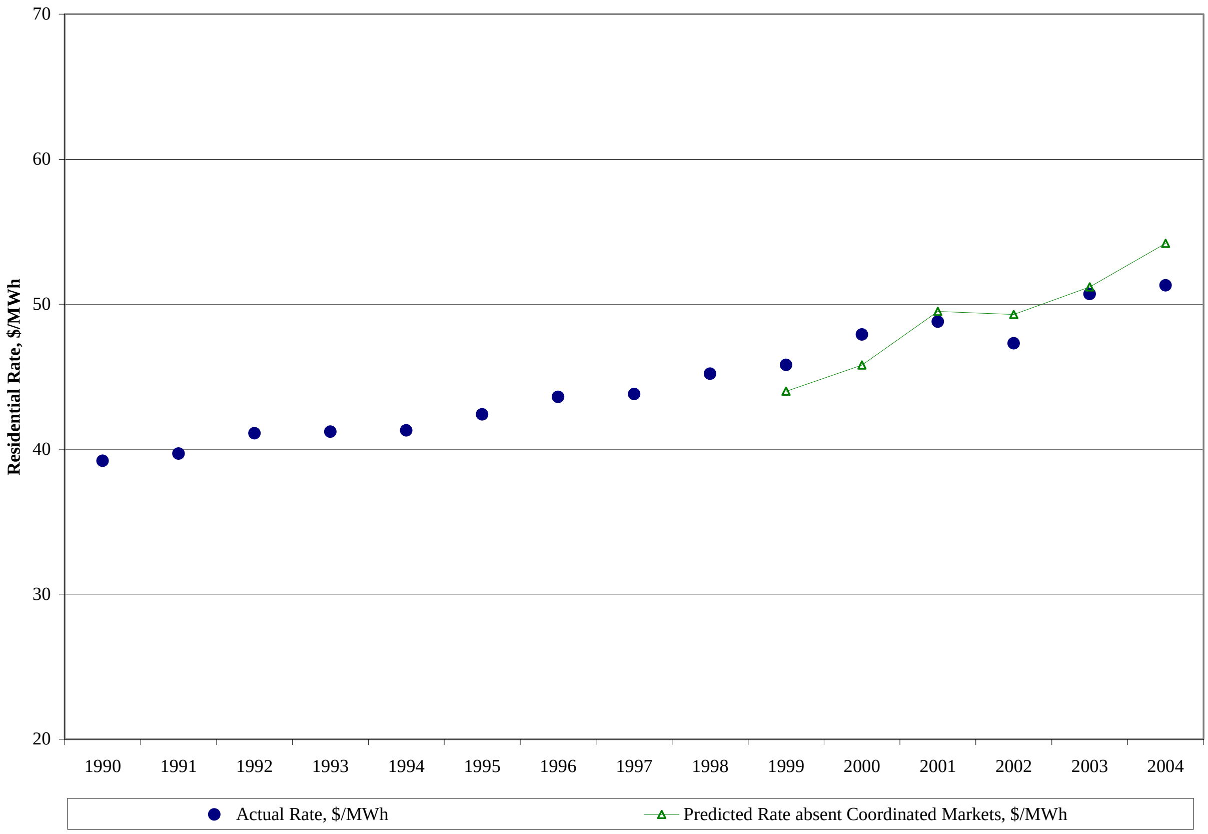
2 As discussed in greater detail below, gas dependence is defined based on 1990 generation patterns so that this classification is independent of subsequent RTO implementation.

3 Western Maryland was part of the Allegheny Power control area in 1998 and hence did not belong to PJM when coordinated markets were implemented in 1998.

Figure 1 portrays the actual average residential rate of NYISO municipal and cooperative utilities over the period 1990 through 2004 and the projected rate, absent implementation of a coordinated market. It is apparent that the actual average rates are generally lower than the predicted rates, absent implementation of coordinated markets, over the period 2000-2004.[4]

Figure 1
Actual and Predicted Residential Rates
NYISO



4 Average retail rates vary from year to year for a variety of reasons that are not controlled for in the study such as year to year variations in average and peak load across the regions analyzed in the study, variations in cost recovery practices across the utilities included in the study, major nuclear plant outages within the regions during particular years, variations in the duration, timing and terms of forward hedging contracts, and differences in year to year changes in fuel costs. Some of these sources of variation are intentionally not controlled for in this study because of the possibility that they are causally related to the implementation of coordinated markets as discussed in Sections II D and II E below.

Similarly, Figure 2 portrays the actual average rate of municipal and cooperative utilities in the gas dependent Eastern PJM region over the period 1990-2004 and the projected rate, absent implementation of a coordinated market. It is apparent that the actual average rate is generally lower than the predicted rate over the period 1998-2004.

Figure 2
Actual and Predicted Residential Rates
Eastern PJM (New Jersey, Delaware, Eastern Maryland)

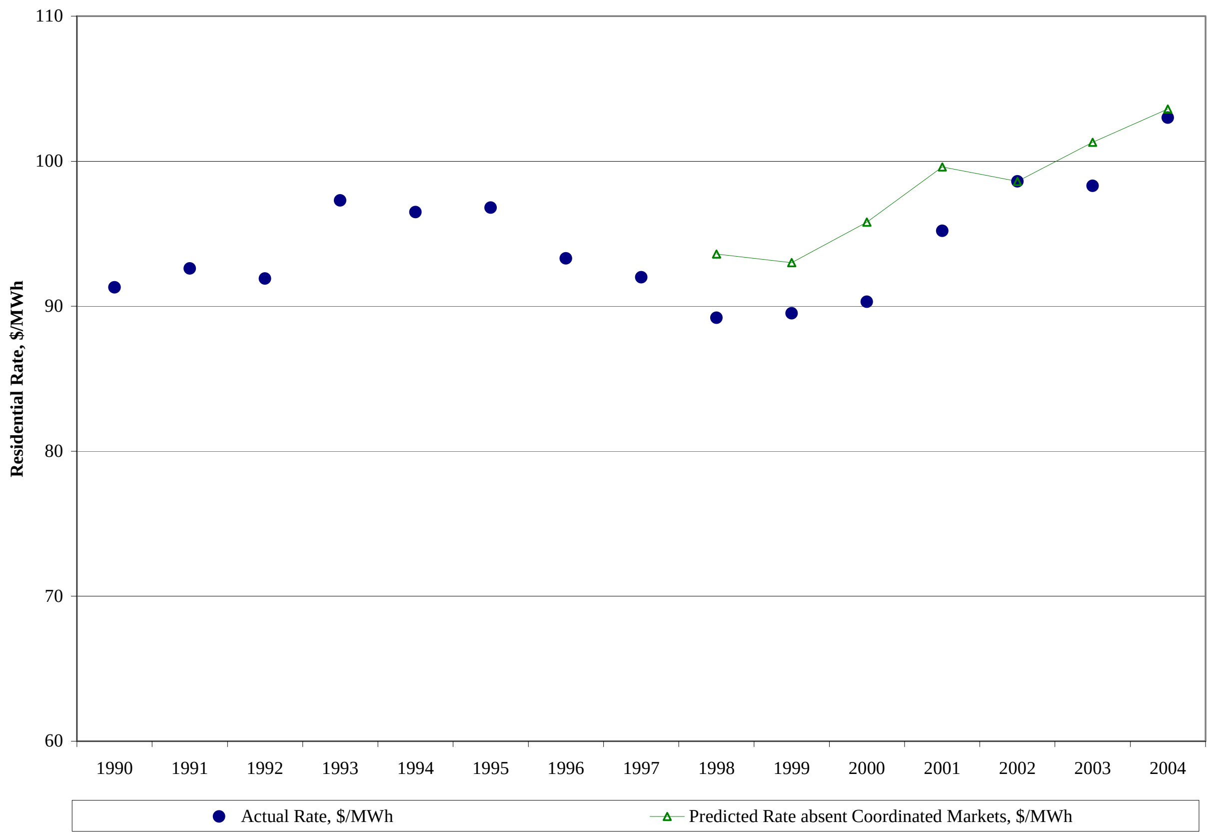
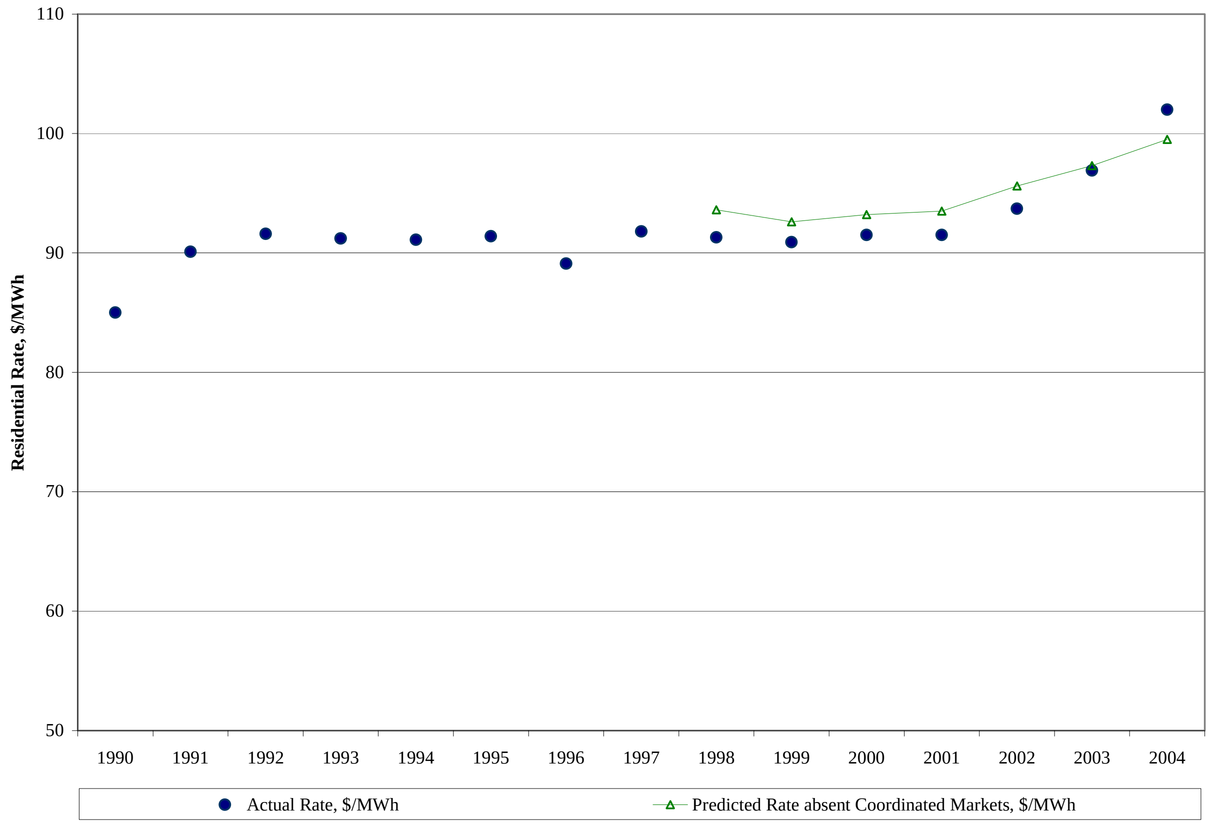


Figure 3 portrays the actual average rate of municipal and cooperative utilities in the low gas dependent PJM state of Pennsylvania[5] over the period 1990-2004 and the projected rate, absent implementation of a coordinated market. It is apparent that the actual average rate is generally lower than the predicted rate over the period 1998-2004.

Figure 3
Actual and Predicted Residential Rates
PJM-Pennsylvania



It is hoped that the focus in this paper on comparing electricity rates in regions with coordinated markets to "what rates would otherwise have been" in these markets will sharpen the discussion of the merits of wholesale electricity market deregulation and implementation of regional wholesale markets based on LMP pricing. There is a need to progress beyond a simplistic focus on the percentage change in electricity rates that does not take into account underlying factors unrelated to the implementation of coordinated markets that have changed over time in all regions, such as increases in fuel prices.

5 This analysis is based on Pennsylvania utilities located in the PJM control area in 1998. Some Pennsylvania utilities did not become part of the PJM control area until 2002 or 2004.

II. STUDY APPROACH

A. Overview

The policy question addressed by this paper is whether the implementation of coordinated markets in PJM and the NYISO provided net benefits to electricity consumers. Conceptually, this requires estimating what average retail rates would have been in these regions, had LMP based coordinated markets not been implemented in PJM in April 1998 and in New York in November 1999. Since PJM and New York did implement LMP based coordinated markets, however, the actual rate data do not allow one to observe how average retail rates would have evolved over time had these market changes not been introduced.

A conventional method of analyzing questions of this type would be to compare average retail rates before and after the implementation of coordinated markets, testing whether rates rose or fell with the change. A fundamental difficulty with such an approach is that in order to identify the effects of implementing coordinated markets, it would be necessary to find a method to measure the change in average rates, holding everything other than the implementation of coordinated markets constant between the two periods. This is not readily accomplished, because many things have changed between the pre-1998 period and the 1998-2004 periods that have likely impacted rates, some materially. One way to attempt to hold other things constant is to compare average electricity rates deflated to reflect the impact of fuel cost changes. These comparisons are informative, but they do not control for other changes that affected average rates, and reasonable people can disagree on the appropriate index that should be used to deflate rates to adjust for changes in fuel costs.

Another complication in applying this before and after approach to measuring the benefits from the implementation of coordinated markets is that many of the states comprising PJM and the state of New York implemented retail access programs largely coincident with the implementation of coordinated markets. The short-term rate caps, stranded cost recovery charges, provider of last resort rates, competitive retailer rates and changes in forward hedging associated with this change, make it difficult to compare average rates before and after retail access in general and make it particularly difficult to identify the long-term rate impact from the implementation of coordinated markets. Some of the complications are:

> Should the comparison be based on provider of last resort prices or competitive retailer prices?
>
> Should the comparison include or exclude stranded cost recovery charges?
>
> How should such a comparison account for short-term caps on provider of last resort rates?
>
> How should such a comparison control for changes in the degree of forward hedging?

A second conventional method of analyzing questions of this type would be to compare average rates in the regions implementing coordinated markets to rates in regions which have not implemented coordinated markets. A difficulty with this approach analogous to the limitation of the before and after approach is that in order to identify the effects of implementing coordinated markets, it would be necessary to hold everything else constant between the two regions. Since there were differences in average consumer rates between the regions prior to implementation of coordinated markets, there are clearly other factors affecting average rates that need to be held constant between these regions. Not all of the differences in average rates observed following implementation of coordinated markets can be attributed to the implementation of coordinated markets. Moreover, there are differences in resource mix (such as dependence on gas-fired generation) and location (dependence on interstate pipelines for gas supply) across states and regions which can affect average rates if these differences are not controlled for in a comparison between regions implementing or not implementing coordinated markets. In addition, the implementation of retail access programs in the states belonging to PJM and New York complicates comparisons between investor owned utility rates across regions in much the same way that it complicates average rate comparisons over time.

A third approach to assessing the rate impacts of the implementation of coordinated markets is to estimate the underlying cost reductions arising from the implementation of coordinated markets. While this approach can identify substantial inefficiencies in regions lacking coordinated markets, such as under utilization of the transmission system,[6] the lack of transparent spot prices in these markets makes it difficult to assign dollar magnitudes to these inefficiencies. Moreover, the methodology is extremely resource intensive if applied to all constraints over a broad region over a meaningful period of time.[7] Such an approach can therefore be very useful in identifying examples of the kind of inefficiencies that exist in regions lacking coordinated markets but is difficult to use this methodology to develop estimates of the overall benefits from implementation of coordinated markets. In addition, this approach also requires a separate analysis of the cost effects from implementation of coordinated markets, in order to calculate the net benefits. While the calculation of direct RTO costs may appear straightforward for existing RTOs, determination of the portion of these costs that are incremental is not straightforward. PJM and the New York Power Pool incurred operating costs prior to implementation of coordinated markets and some of the factors that have raised RTO costs in recent years would also have raised the costs of the PJM OI and New York Power Pool had coordinated markets not been implemented. The implementation of coordinated markets also both raises and lowers the costs of the utilities in those regions, which needs to be taken into account in a calculation of net benefits.

Recognizing the difficulties of these three general approaches, the challenge of this study was to design a conceptual approach for identifying the impact on average consumer electricity

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6 See, for example, Direct Testimony of Dr. Ronald R. McNamara, Commonwealth of Kentucky, Public Service Commission, Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc. Case No. 2003-0266, December 29, 2003, pp. 13-14, 16; and MISO, "The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets, Initial Results," March 26, 2004.

7 The extremely high resource demands of analyzing the level of inefficiency in day-ahead and real-time schedules in traditional markets can be reduced through use of simulation tools for these comparisons, but the inefficiency in traditional markets is inherently difficult to reproduce in simulation models based on optimization.

rates of implementing coordinated electricity markets while controlling for the impact of changes in fuel prices, differences in gas dependence among utilities, and the effects on rate design and forward hedging of utilities of state retail access programs. The first methodological hurdle was to find a way to distinguish the impact on retail electricity rates of economic trends, such as rising fuel prices, from the impact of implementing coordinated markets. Since fuel prices have risen relatively sharply since the implementation of coordinated markets in PJM and New York, average retail rates have also risen over this period in these regions. This increase over time in average retail electricity rates is not necessarily attributable simply to the implementation of coordinated markets, however, as fuel prices and retail electricity rates have also risen in regions that have not implemented coordinated markets. The second methodological issue was the need to control for the impact on average retail rates of differences in retail access programs across utilities and regions. The concern was that the essentially identical timing for the implementation of coordinated markets and state retail access programs would make it difficult or impossible to distinguish the rate impacts of retail access implementation from the retail rate impacts of implementing coordinated markets.[8] The third major issue was to find an appropriate way to take into account the impact of differences in regional generation fuel mix, in particular, gas dependence, on changes over time in average retail electricity rates.

As described below, these issues have been addressed by the use of a pooled time series cross sectional model to control for changes over time in costs, particularly fuel price changes; by restricting the sample to utilities not subject to state retail access programs to isolate the effects of implementing coordinated wholesale power markets; and by separately analyzing rate trends in historically gas dependent and not gas dependent regions to control for regional fuel mix differences. In addition, the model includes a variety of other variables unrelated to implementation of coordinated markets to control for utility specific cost factors potentially impacting average consumer rates, such as utility size.

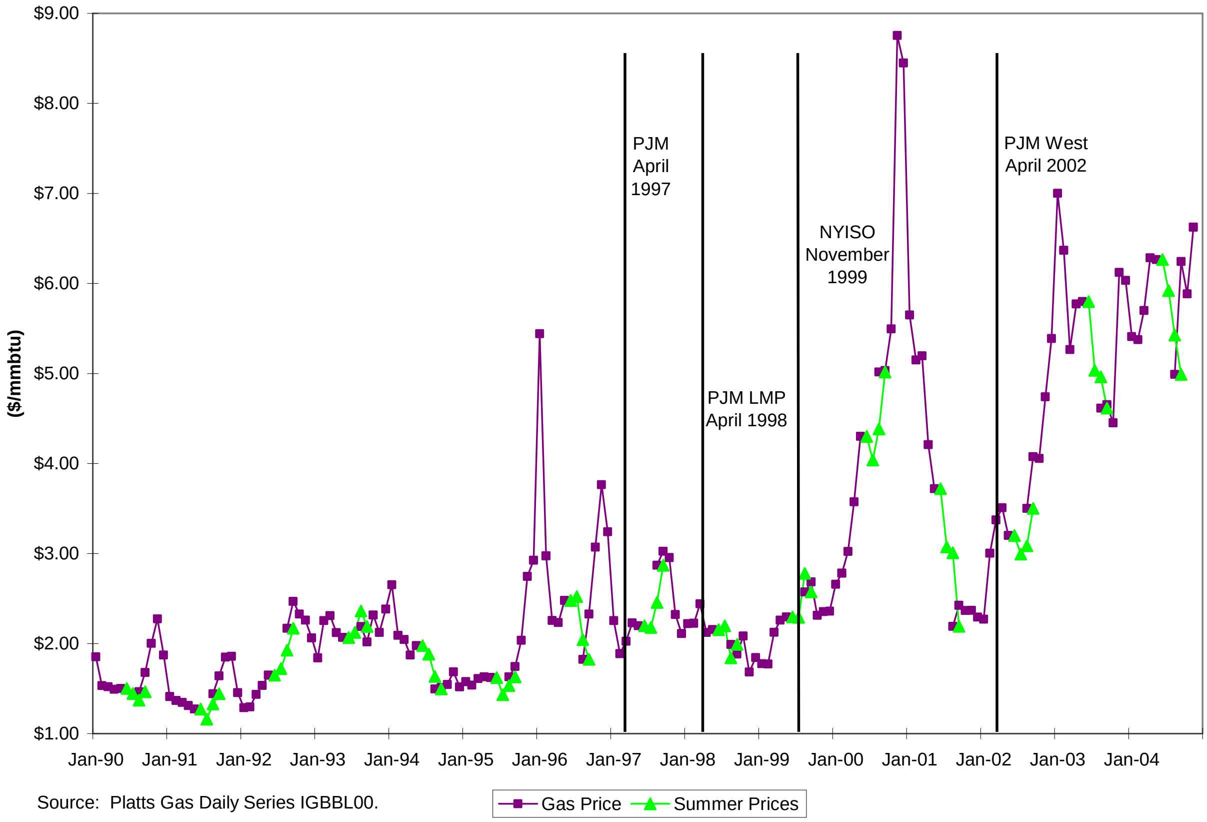
B. Controlling for Cost Changes

The first methodological hurdle – distinguishing the impact of market coordination from the impact of cost changes, particularly increasing fuel prices, that have affected average retail rates – has been addressed through the use of a combined cross section and time series model. The policy question addressed by this study is "does the implementation of coordinated markets raise or lower consumer rates, other things being equal?" The study uses a sample of utilities operating in both organized and traditional environments over a period of time to provide the basis for addressing this question.

8 In addition, the rate caps, provider-of-last-resort rates, and stranded cost recovery charges often associated with implementation of retail access can greatly complicate identification of the long-run rate impacts.

Gas prices have risen substantially since implementation of coordinated markets in PJM and NYISO as shown in Figure 4. Thus, a time series analysis of average retail rates in these regions would likely show rising average retail rates but this trend would not necessarily be attributable to the implementation of coordinated markets. Conversely, a time series analysis of average retail rates in regions that have not implemented coordinated markets would also show rising average retail rates over the same period but this also would not necessarily be attributable to a failure to implement coordinated markets.

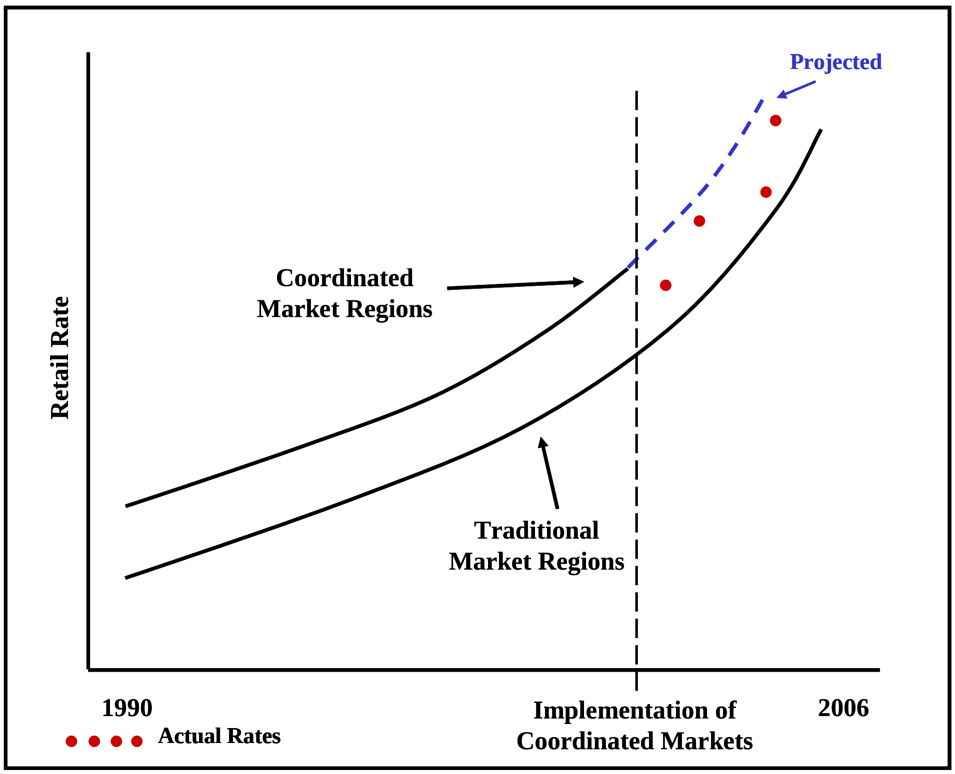
Figure 4
Henry Hub Gas Prices and Market Changes



A single period study comparing average retail electricity rates in coordinated market regions to those in other regions can show the relationship between electricity prices in the coordinated market regions versus traditional market regions at a given point in time, but such a study cannot provide a basis for inferring whether the differences reflected pre-existing cost differences or the impact of implementing coordinated markets. For example, a comparison of the 2004 average rates of the New York utilities analyzed in this study to the rates of the Florida utilities in the study finds that the average New York rates were roughly half the residential rates in Florida. This entire difference should not be attributed to the implementation of coordinated markets in New York, however, because the average retail rates in New York were also much lower than the average Florida rates in 1990, prior to the implementation of coordinated markets in New York. In addition, a comparison of average rates at a single point in time would not be able to distinguish whether an observed difference in average retail rates reflected a continuing rate impact or short-term variations arising from transitory differences in power or fuel contract expiration dates, rate change timing or cost pass-through provisions.

The use of a pooled time series-cross section model based on annual time-series data for both utilities in organized markets and utilities operating in traditional markets over the period 1990-2004[9] enables the study to distinguish how the implementation of coordinated markets changed the trajectory over time of average rates of the utilities in the coordinated markets, *relative to the rate trajectory of the utilities in the traditional markets.* The study uses the relationship between utility consumer electricity rates in the coordinated market region and the traditional market region during the period prior to implementation of coordinated markets to project what the consumer rates would have been in the coordinated market region absent implementation of coordinated markets as illustrated in Figure 5.[10] The effect of coordinated markets is identified from how actual average rates of the utilities in the coordinated market region deviated from the projection following the implementation of coordinated markets, as illustrated in Figure 5.

Figure 5
Analyzing Actual and Projected Rates



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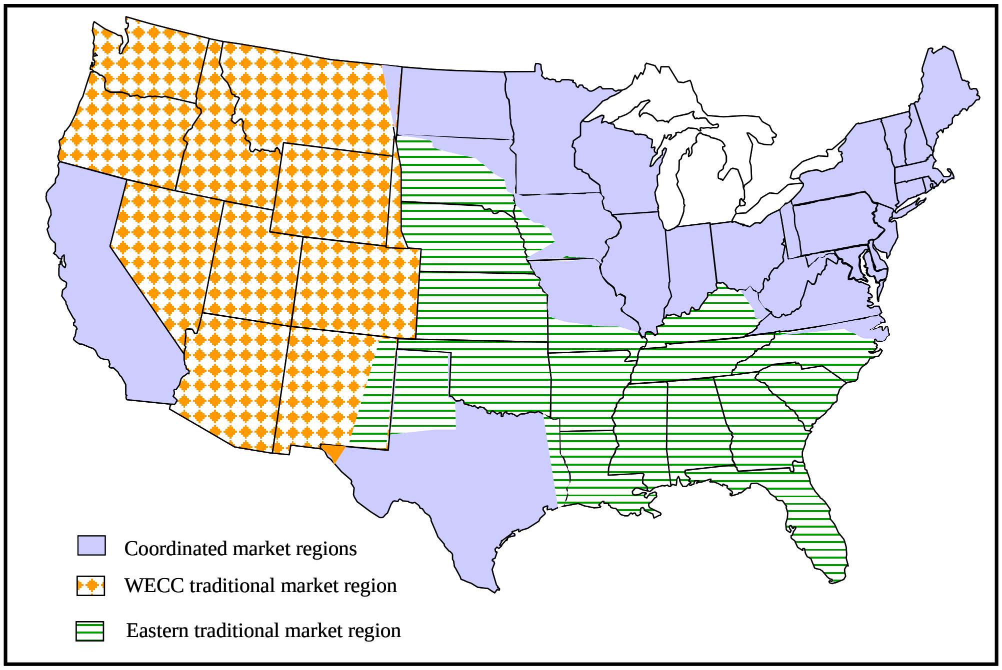
9 As discussed below, the study is limited to the period through 2004 because data used for the empirical analysis are not yet available for 2005.

10 Several factors, such as differences in retail access and fuel mix could lead the same economic trends to have different impacts on different utilities. The sections below discuss how the study addressed these issues.

The variables used to control for changes in cost differences over time and to project utility rates in the coordinated market region fall into three groups. First, the model includes a control variable (a dummy variable) for each utility in the sample. This variable controls for utility-specific historical cost differences allowing the model to project rate trajectories for each utility that reflect these historical cost differences. Second, the model includes a control variable (a dummy variable) for each year covered by the study.[11] In effect the yearly dummy variables allow the model to use the historical data to estimate annual changes in average rates across the sample for each year of the sample, i.e., the coefficient of the dummy variable for a year. These estimates project how the average rates of each utility change from year to year relative to the estimate of each utility's specific starting point. Third, the model includes control variables for each utility's total sales in each year, residential sales per customer in each year, and proportion of sales going to industrial customers in each year, since each of these variables is expected to have a systematic impact on the average residential rates of individual utilities.[12]

Given the use of a cross-sectional, time-series framework, the next step was the identification of the coordinated and traditional markets region to be included in the analysis. Figure 6 portrays the coordinated and traditional market regions in the continental United States as of fall 2006.

Figure 6
Coordinated and Traditional Market Regions as of Fall 2006



[11] The 1990 rate is reflected in the constant term; the other annual variables measure the change relative to the 1990 rate.

[12] The econometric model estimated is therefore of the form:

$$Rate_{it} = C + Year_t + Utility_i + B_1\ Size_{it} + B_2\ Sales\ Per\ Customer_{it} + B_3\ \%\ Industrial_{it} + B_4\ Coordination_{it}$$

Several of the coordinated market regions portrayed in Figure 6 were not included in the coordinated markets analyzed in this study. First, the non-LMP markets operating in California and ERCOT were not included in the analysis. The market designs in these regions are in the process of being replaced with LMP based markets, so there is little point in analyzing the relative performance of these market designs. Second, coordinated LMP based markets were implemented over a wide region of the Midwest during 2004 and 2005. Utilities located in this region have not been included in the analysis because of the very short period of time in which these markets have been in operation. The MISO LMP market did not begin operation until March 2005 and PJM expanded into Ohio, Illinois, Virginia and portions of Michigan, Kentucky and Indiana during 2004 and 2005. Third, New England has also not been included in the analysis. LMP was implemented in New England on March 1, 2003 providing only two years of operating data from the data source used in this study. In addition, LMP implementation followed a lengthy period of operation under a non-LMP market design, muddling the cause of any differences in rates that might be identified during late 2003 and 2004.[13]

The utilities located in the coordinated market regions that are analyzed in this study, therefore, include utilities located in classic PJM (i.e., the PJM control area as of April 1999 – eastern Pennsylvania, Delaware, District of Columbia, Maryland and New Jersey) and the NYISO. These regions have been operating under LMP-based competitive markets for five or more years. This allows a comparison of classic PJM and NYISO utility electricity prices before versus after the change in their market structure to the electricity prices of utilities operating in more traditional markets over the full period of the study. In addition, the study includes a sensitivity analysis in which the Allegheny Power utilities are included in the analysis. The Allegheny Power control area became part of PJM on April 1, 2002, so there is a shorter period of time over which to observe the effects of implementing coordinated markets than for the NYISO and classic PJM but longer than for New England or the Midwest.[14]

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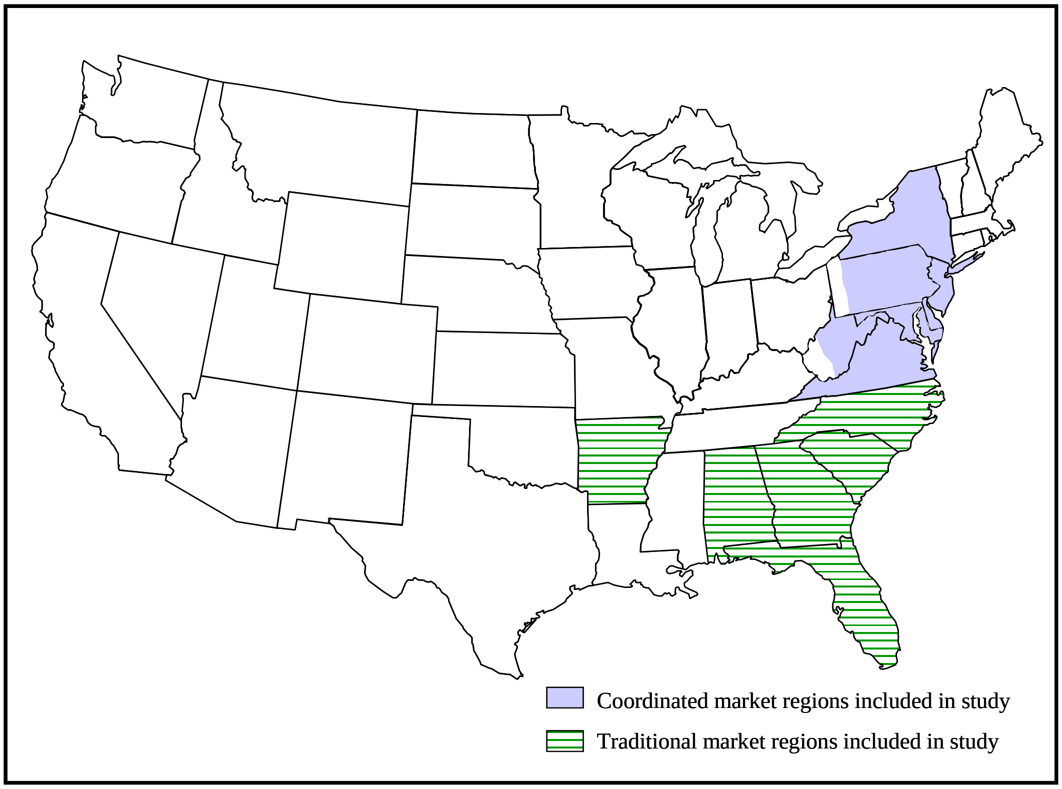
13 Since the non-LMP market design was in place for longer, 1999 to 2003, than the current LMP design has been in operation, it would be necessary to not only project what rates would have been under the original traditional market structure in New England but to also estimate how the subsequent market design changed this trajectory. While it might be possible to develop a methodology for disentangling these effects, we did not attempt to develop such a methodology for this study.

14 The rate impact of implementing coordinated markets is potentially greater for Allegheny consumers than for the customers of PJM and New York utilities, since these latter regions had been operating as part of a cost based pool for many years.

Figure 7
Regions Analyzed in the Study



The utilities located in traditional market regions for the purpose of this study include utilities in the Southeast and Mid-continent that have never participated in a coordinated market. Utilities in the western interconnection were not included because it was judged too difficult to control for the rate impacts of the western hydro cycle in comparing between western traditional utilities and utilities in the coordinated markets in New York and PJM.[15] TVA utility customers are also excluded from the analysis since they operate in an environment that differs markedly from that of utilities operating in traditional markets. Utilities on the Western edge of MISO that have not yet become MISO members have not been included in the analysis.

The utilities in SERC (other than Dominion), Florida and Arkansas are therefore used as the comparison sample of utilities operating within traditional market regions. The study requires a sample of utilities that have remained within the traditional regulatory framework over the entire period studied, to enable the analysis to use the pattern of changes in average rates in the

[15] While it might be possible to draw comparisons between coordinated market regions and traditional market regions both located within WECC and thus subject to the same hydro cycle, there is currently no LMP based coordinated market operating in the WECC region.

traditional market region to project the average rates in PJM and New York, absent implementation of coordinated markets.[16]

C. Controlling for Retail Access

The regions that were first to implement organized wholesale markets also adopted state retail access programs at essentially the time that coordinated markets were implemented. A second challenge in identifying the effect on average consumer rates of implementing coordinated markets is to distinguish the effects of implementing coordinated power markets from the effects of the various state retail access programs.[17] Retail access programs likely impact the average retail rates of the investor-owned utilities in different ways and at different points in time. In particular, to the extent that retail access programs are associated with less forward hedging by or on behalf of consumers than is the case under the traditional vertically integrated regulated utility model, retail prices under retail access systems may be more cyclical than elsewhere, i.e., lower than elsewhere when wholesale prices are declining and higher than elsewhere when wholesale prices are rising.[18] In view of the correlation between retail access implementation and participation in organized wholesale markets, a major conceptual problem confronted in this study was to distinguish between the rate impacts of organized markets and the rate impacts of reduced forward hedging associated with retail access programs.

One potential method of distinguishing the effects of retail access from the effects of implementing coordinated power markets would be to use a control group of vertically integrated utilities in states that have not adopted retail access programs but have implemented coordinated markets. The difficulty with utilizing this approach at this point in time is that virtually all of the

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16 Utilities operating in the MISO region and post 2002 PJM control area have therefore not been included in the model during the pre-MISO period because we cannot use their current rates to project rates under the traditional market design, since the MISO region was in the process of shifting to coordinated markets during this period.

17 Essentially the same distinction is present in natural gas markets. While FERC open access requirements apply to all interstate natural gas pipelines, it is in large part a matter of state regulatory policy whether the local distribution company continues to contract forward for gas on behalf of some or all of its customers or whether this responsibility is shifted to the customers. Different states have adopted distinct policies regarding retail access in gas while operating within a uniform national open access policy for interstate gas pipelines (the analogue to coordinated wholesale power markets in electricity.

18 Such a reduction in forward hedging is not necessarily undesirable from the standpoint of power consumers as it could reduce power costs over the long-run. For example, if some utility load values power at less than $90/MWh it would not be efficient to enter into hedges to buy power during periods of spot prices in excess of $90/MWh, as those customers would prefer to sell the power at those spot prices than consume power that is worth less to them than its spot market price. If traditional market structures lacking transparent spot markets require public utilities to contract forward for power without the option of selling spot market power that costs more than its value to their marginal consumers, the transition to coordinated markets with transparent spot markets could be associated both with reduced hedging and long-run increases in consumer welfare.

Even if changes in the level of hedging are beneficial to consumers, however, these changes would tend to bias comparisons of differences in average rates at particular points in time or over short periods of time. Reductions in hedging will tend to appear benefit consumers more than is actually the case when current spot prices are above past forward power prices and will tend to appear to raise average consumer rates when current spot power prices are higher than past forward prices.

investor owned utilities meeting this dual test are located in the Midwest ISO. Since the Midwest ISO only implemented coordinated markets on April 1, 2005, there is too little data at this point in time to draw any conclusions regarding the impacts on average consumer rates of implementing coordinated markets in this region.

Another potential method of distinguishing the effects of retail access from the effects of implementing coordinated power markets would be to control for differences in forward hedging between the customers of investor owned utilities in traditional market regions and those in regions in which retail access has been implemented. While interesting from a theoretical perspective this approach was judged to be unworkable in practice. Applying such an approach with sufficient accuracy to draw meaningful conclusions would have required much better data on forward contracts (both for power and fuel) than is available. An approach based on analysis of the average rates of investor-owned utilities subject to retail access programs would also have required controlling for stranded cost recovery charges at the distribution company level, while analyzing the average rates both of provider of last resort and competitive supplier customers.

In view of the unworkability of these approaches to controlling for the rate impacts of retail access, the decision was made to focus the study on a comparison of average retail rates across utilities retaining a traditional long-term obligation to serve load, for a sample drawn from both utilities operating in coordinated and traditional markets. Since the obligation to serve has been retained in New York and PJM by public power entities, such as municipal utilities and cooperatives, the study compares the average retail rates of municipal utilities and cooperatives operating within coordinated wholesale markets with those operating in regions retaining the traditional utility market structure. In both coordinated and traditional markets these public utilities have retained the obligation to serve and have the ability to manage their energy costs by operating power plants or purchasing power under long-term contracts, and can lock in transmission costs by buying congestion hedging financial instruments or traditional firm transmission rights. Thus, we would not expect changes in relative fuel price to have a systematically different impact on the municipal utilities and cooperatives operating in coordinated versus traditional markets, since they both have the same opportunity and need to hedge such wholesale price changes. Differences in the details of retail access programs do not impact the comparison of the retail rates of public power entities operating in coordinated versus traditional markets, so the use of a sample of municipal and cooperative utilities provides a relatively clean way to isolate the impact of coordinated markets on retail prices.

The state and regional distribution of the municipal and cooperative utilities included in the study is shown in Table 8.

Table 8
Public Utilities by State and Region

Sales Location	Cooperative	Municipal	State	Total	Total Retail MWh, 2004
NYISO/NYPP	4	47	-	51	4,863,191
PJM Interconnection	14	46	-	60	11,115,982
Allegheny Power	5	8	-	13	1,849,535
Alabama	15	19	-	34	10,267,984
Arkansas	17	15	-	32	16,919,383
Florida	16	31	-	47	49,848,685
Georgia	41	50	-	91	43,744,979
North Carolina	28	70	1	99	30,170,634
South Carolina	20	21	1	42	29,342,462

Source: EIA-861, Appendix A.

D. Controlling for Fuel Mix

A third major issue in analyzing the effects of implementing coordinated wholesale power markets was to find an appropriate way to take into account the impact of differences in generation fuel mix on average retail rates. While the generation mix used to serve customer load reflects utility choices, these choices are constrained by regional characteristics. The reality is that construction of coal-fired generation within their service territory has not been an option for utilities in some regions and this constraint existed long before the implementation of coordinate markets in those regions.[19] Average retail rates in the oil- and gas-fired generation dependent regions tend to rise more than elsewhere when oil and gas prices rise and conversely decline more when oil and gas prices fall. Florida is the state in the Southeast that has retained a

[19] Indeed, many state to state differences in interest in retail access derive from the difficulties over the past 35 years of the utilities that were highly dependent on oil-fired generation in 1972 prior to the first oil price shock.

traditional power market structure and that has historically been most like New York, New Jersey, Delaware and Eastern Maryland in terms of reliance on gas- and oil-fired generation as shown in Table 9.[20]

Table 9
Regional Fuel Mix Differences, 1990

	Percent Gas and Oil Generation[1]
Coordinated Power Markets	
New York	41.8
Delaware	32.6
New Jersey	22.5
Maryland	15.4
Pennsylvania	4.3
West Virginia	0.5
Traditional Power Markets	
Florida	33.6
South Carolina	1.4
Georgia	1.3
North Carolina	0.6
Alabama	1.5
Arkansas	9.4

[1] As a percentage of total state generation (MWh).
Source: http://.www.doc.gov/eneaf/electricity/epa/generation_state.xls

While the current fuel mix could have been included as an explanatory variable in the econometric analysis, we recognize that a concern has been expressed that fuel mix choices have been influenced by market design choices and, in particular, that implementation of coordinated markets has directly or indirectly increased reliance on gas-fired generation. Given this concern, a variable controlling for current fuel mix choices might not be independent of whether or not a region has made a change from a traditional to a coordinated electricity market structure. Rather than controlling for current utility gas dependence, therefore, the study controls for historical regional oil and gas dependence, segregating the sample based on the degree of regional reliance on oil- and gas-fired generation in 1990. The level of oil- and gas-fired generation in 1990 is not attributable to the subsequent implementation of RTOs (i.e., it is exogenous). Thus, the analysis

[20] These data reflect the proportion of the power generated in each state (measured in megawatt hours, i.e., energy, not megawatts of capacity) that was generated from oil- or gas-fired generation. Some states have load in excess of their generation output and therefore imported power to meet load, while other states have generation output in excess of their load and therefore exported power. While consumer load within a gas dependent region such as eastern PJM can be met in part with imported coal-fired power, the inability to construct coal-fired generation close to load raises the cost of meeting load located in these regions with coal-fired generation.

has sought to take account of historical fuel mix constraints, but attempts to avoid confusing the impact of fuel mix on average retail rates with that of market coordination.

The study uses state-level data on 1990 generation mix to separate the public utilities into two samples, one of public utilities operating in regions with historically high gas dependence (New York, New Jersey, Delaware, eastern Maryland and Florida) and those operating in regions with little oil and gas dependence in 1990 (Pennsylvania, Western Maryland, West Virginia, North Carolina, South Carolina, Georgia, Alabama and Arkansas), as shown in Table 9.[21] The analysis of average retail rates is carried out separately for the two samples, allowing us to model the impact of market coordination in regions with a relatively high ratio of oil and gas generation in their total generation mix and the impact in regions with a much lower use of oil and gas generation.

E. Summary of Conceptual Approach and Data

The analysis of the effect of implementing coordinated markets on average retail rates is complicated by three issues:

> In most regions, implementation of coordinated markets has coincided with implementation of retail competition, making it difficult to distinguish the impact on average rates of the two changes.
>
> The implementation of coordinated markets has also largely coincided with a rise in natural gas prices, again making it difficult to distinguish the impact on average rates of implementing coordinated markets.
>
> The degree of dependence on oil- and gas-fired generation varies across the states.

These complicating factors have been addressed in this study by using a pooled cross section and time series model to project rates in coordinated market regions, by restricting the sample to public utilities not subject to retail access, and by segregating the study between oil and gas dependent and other regions.

The data set for this study of retail electricity rates consists of annual data for municipal and cooperative utilities for the years 1990-2004. The dependent variable in the regression analysis is the average annual residential retail rate of utility i in year t measured as Annual Residential Revenues/Annual Residential Sales in megawatts.[22] The source of the annual revenue and megawatt sales data is the EIA Form 861: 1990-2004.[23] The analysis of average

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21 There is a third potential sample, oil and gas dependent power markets in gas producing regions with wellhead or intrastate gas pipeline supply sources, Texas, Oklahoma, Louisiana and Mississippi. Until ERCOT and/or SPP implement LMP markets, however, there is no coordinated market within this region to use to identify the effects of implementing LMP based coordinated markets.

22 The use of average annual rather than monthly data is appropriate for this analysis since we are interested in identifying long-run rate differences. While there are very likely differences in the timing of cost passthroughs across the sample, the impact of these differences should be greatly reduced for annual data.

23 The 2005 data will not be available until late 2006.

rates is based on average residential rates, rather than average commercial or industrial rates, because it is anticipated that residential customers are relatively homogenous across the sample compared to industrial customers in particular, so the inability to control for customer characteristics will be less important when analyzing average residential rates than might be the case for an analysis based on industrial or commercial rates.

In analyzing factors affecting residential rates, the study includes the following control variables:

Total Retail Sales (i,t): total load of utility i in year t (source: EIA Form 861).

Average Residential Sales per Customer (i,t): residential sales of utility i in year t divided by the number of residential customers of utility i in year t (source: EIA Form 861).

Percentage Industrial Load (i,t): industrial load of utility i in year t divided by total load of utility i in year t (source: EIA Form 861).

Coordinated Market Dummy (i,t):

> For utilities in classic PJM, equal to 0 for the years 1990-1997, equal to 2/3 for the year 1998, and equal to 1 for the years1999-2004.
>
> For utilities in New York, equal to 0 for the years 1990-1998, 0.125 for the year 1999, and 1 for the years 2000-2004.
>
> For utilities in the Allegheny control area in 2001, equal to 0 for the years 1990-2001, 2/3 for the year 2002, and 1 for the years 2003-2004.
>
> For utilities that are not in classic PJM, Allegheny or New York, 0 in all years.

Allegheny Impact Dummy (i,t): For all utilities not located in the Allegheny control area, 0 in all years. It also takes the value zero for all utilities in the Allegheny control area prior to 2002. For utilities in the Allegheny control area this variable takes the value 2/3 in 2002, and 1 in 2003 and 2004.

The total effect of implementing coordinated markets on utility rates in the Allegheny control area is the sum of the Coordinated Market coefficient and the Allegheny Impact coefficient.

Annual Dummies (t): equal to 1 for all utilities for year t and 0 otherwise. For example, the 1991 Dummy is equal to 1 for all utilities for the year 1991 and 0 otherwise. There are 14 annual dummy variables, one for each year from 1991-2004.[24]

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[24] The coefficients of the annual dummies measure rate differences relative to the base year, 1990, whose rates are described by the constant term.

Individual Utility Dummies (i): equal to 1 for utility i in all years t, 0 for all other utilities in all years. There is one utility dummy for each utility except one whose rates are reflected in the constant term.[25]

The regression equation that is estimated is of the form:

$$\text{Rate}_{it} = C + \text{Year}_t + \text{Utility}_i + B_1\ \text{Size}_{it} + B_2\ \text{Sales Per Customer}_{it} + B_3\ \%\ \text{Industrial}_{it} + B_4\ \text{Coordination}_{it}$$

Perhaps as important as the control variables included in the analysis are those that have not been included. In particular, the model does not control for differences in regional gas prices. This approach was adopted to address the potential concern that changes in the level of investment in gas storage, dual fuel capability or pipeline capacity that impacted gas prices were causally related to implementation of coordinated markets. Instead, the model in effect uses rates in the traditional market regions to estimate the annual dummy variables which proxy for fuel and other cost changes over the period that affected average rates in both traditional and coordinated market regions. The annual dummy variables also proxy for the impact on average rates of national regulatory changes, such as Order 888 and changes in economic conditions.

Since the same annual dummy variable projects the average rates of utilities located in both traditional market regions and coordinated market regions, the model addresses the concern that the observed level of a control variable for regional economic conditions might in fact be a result of the coordinated market effects that we seek to measure.[26] This approach has the advantage that, to the extent that coordinated market implementation indirectly affects average consumer rates through impacts on gas prices, the model will identify the ultimate impact on average consumer rates as the result of implementing coordinated markets. Conversely, however, because the model does not control for distinct regional cost trends, to the extent there are such trends that are both independent of coordinated market implementation and correlated with coordinated market implementation their effects will be reflected in part in the coordinated market variable.

The model also does not control for changes in state taxes collected from electric utilities.[27] Thus, to the extent that there was an increase in the taxes paid by electric utilities, and thus recovered in their rates, that was correlated with coordinated market implementation, the impact of these tax increases on average rates would be reflected in part in the coordinated market variable.

Appendix A contains a detailed discussion of the construction of the sample and related data issues.

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25 The coefficients of the utility dummies therefore measure rate differences relative to the utility whose rates are described by the constant term.

26 For example, if investment incentives associated with implementation of coordinated markets led to higher gas prices in regions implementing coordinated markets, including a measure of regional gas prices as a control variable could result in this effect being captured in the coefficient of the gas price variable rather than by the coordinated market variable.

27 By a tax collected specifically from electric utilities we mean to exclude taxes such as property taxes, or corporate income taxes that all firms in the state pay.

III. RESULTS

Average public utility residential rates in New York, New Jersey, Delaware, and PJM-Maryland were compared over the period 1990-2004 to average public utility rates in Florida, a state that has maintained a traditional utility market structure and in 1990 had a level of reliance on oil- and gas-fired generation and dependence on interstate pipelines that was similar to the 1990 resource mix in New York, New Jersey, Delaware, and eastern Maryland. Thus, average rates in Florida over the period 1998-2004 are used to project the average rates in eastern PJM and New York in this period, given the relationship between average rates in Florida and PJM and New York that existed over the period 1990-1997. In this analysis, the estimated rate impact of coordinated markets is to reduce average retail rates in the coordinated market region by around $1.5 per megawatt hour, as shown in Tables 10 and 11. The differences in average rates are statistically significantly different from zero at traditional confidence levels.

Table 10
Utility Dummy Model

Coordinated Market Impact (t-statistics in parentheses)		
	Coordinated Market	**Additional Allegheny LMP Impact**
East Coast Gas Dependent Regions (n = 1830) $r^2 = .947$		
Florida, New York, New Jersey, Delaware and Maryland	-$1.621/MWh (2.61)	
Low Gas Dependence Regions (n = 4995) $r^2 = .843$		
Pennsylvania, North Carolina, South Carolina, Georgia, Alabama, Arkansas	-$0.879/MWh (1.41)	
Low Gas Dependence Regions And APS (n = 5190) $r^2 = .853$		
Pennsylvania, APS Maryland, West Virginia, Carolina, South Carolina, Georgia, Alabama, Arkansas	-$.803/MWh (1.30)	$0.708/MWh (0.50)

The analysis also compares average public utility residential rates in the portion of Pennsylvania that belonged to PJM in 1998, to public utility rates in North Carolina, South Carolina, Georgia, Alabama and Arkansas, regions which had low levels of oil- and gas-fired generation in 1990. In this analysis, the average rates in South Carolina, North Carolina, Georgia, Alabama and Arkansas over the period 1998-2004 are used to project the average rates in Pennsylvania over these years, given the relationship that existed between average rates in Pennsylvania and the Southeast over the period 1990-1997. For this sample, the impact of implementing coordinated markets has been to reduce retail rates by in the range of $.80 to $1.80

per megawatt hour as shown in Tables 10 and 11, although not all of the coefficient estimates are statistically different from zero at traditional confidence levels.

The signs of the control variables in the regressions are generally consistent with expectations (i.e., negative for total utility sales and negative for average per customer residential load). The sign of the proportion of industrial load varies from positive to negative between the regressions for the gas dependent and non-gas dependent region.[28] The estimated coefficients of the annual dummies that proxy for national fuel price trends tend to move roughly in line with Henry Hub gas prices.

In addition to estimating the model using utility dummy variables to control for utility specific rate effects, an alternative model was estimated that used each utility's 1990 average residential rate as a control variable. The effect of including the 1990 utility rate as a control variable is similar to using utility dummy variables but it imposes greater restrictions on the model relative to the data. This model in effect projects each utility's rates over time based on its 1990 rate, using the annual dummies and changes in utility sales, sales per residential customer and proportion of industrial sales. This model has a lower r^2 than the utility dummy model, particularly for the model estimated for the non-gas dependent regions. The estimated effects on average rates of implementing coordinated markets are generally similar to the effects

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[28] Tables reporting control variable coefficient estimates are included in Appendix B.

estimated in the utility dummy model as summarized in Table 11. For the non-gas dependent regions, the 1990 rate model finds a larger average rate impact from implementation of coordinated markets than the utility dummy model (and this impact is statistically different from zero at conventional confidence levels).

Table 11
1990 Rate Model

Coordinated Market Impact (t-statistics in parentheses)		
	Coordinated Market	**Additional Allegheny LMP Impact**
East Coast Gas Dependent Regions (n = 1830) r^2 = .892		
Florida, New York, New Jersey, Delaware and Maryland	-\$1.415/MWh (2.01)	
Low Gas Dependence Regions (n = 4995) r^2 = .631		
Pennsylvania, North Carolina, South Carolina, Georgia, Alabama, Arkansas	-\$1.871/MWh (2.61)	
Low Gas Dependence Regions And APS (n = 5190) r^2 = .656		
Pennsylvania, APS Maryland, West Virginia, Carolina, South Carolina, Georgia, Alabama, Arkansas	-\$1.474/MWh (-2.08)	-\$.297/MWh (.16)

The Allegheny Impact dummy variable, which tests for any difference in the effect of implementing coordinated markets between western PJM and the APS control area, is not statistically different from zero in either the utility dummy model or the 1990 rate model and has different signs in the two models. This ambiguity may be a result of the limited time period that these utilities have participated in coordinated markets and the limited number of public utilities located in this control area.[29]

[29] We further tested whether the variance of the error term (measured as the square of the estimated residual) was correlated with utility sales, anticipating that the residential rates of smaller utilities might have greater year to year volatility. This appears to be the case for the same as log (residual squared) is inversely correlated with log(total utility sales) at high confidence levels (except for the 1990 rate model for the gas dependent region). The apparent existence of heteroskedastic residuals indicates that the estimated variances of the coefficient estimates may be incorrect. We therefore reestimated the standard errors to calculate robust standard errors, reported in Tables C-1 and C-2 in Appendix C. This generally resulted in a small increase in the estimated standard errors. In addition, we divided the data by the square of the variance estimated from residuals of the regression of the squared residual and reestimated the model. These results are reported in Tables C-3 and C-4 of Appendix C. The estimated impact of coordinated markets and the associated confidence interval are virtually unchanged for the gas dependent region models. The estimate of coordinated market rate impacts is reduced for the non-gas dependent region but continues to predict rate decreases.

The statistical analysis of average consumer rates focuses on the average residential rates of public utilities, rather than commercial and industrial rates or the rates of investor owned utilities. It is important to keep in mind that the rationale for this focus on the average residential rates of public utilities is to isolate the effects of implementing coordinated markets from the effect of retail access and to simplify comparisons of average rates, given the diversity of industrial and commercial consumers. The structure of the analysis is not intended to limit the applicability of the conclusions. Absent reason to believe that the implementation of coordinated markets change the cost allocation of public utilities between residential, commercial and industrial customers, it can be presumed that the rate impact estimate generalizes to all consumers. Similarly, absent reasons to believe that public utilities benefit disproportionately from the implementation of coordinated markets, the average rate impact estimates should generalize to all consumers in RTO regions, whether served by public utilities or investor-owned utilities.

The average rate impacts estimated in this study are based on a relatively short-period of RTO operation and cover a period of evolving RTO market designs and requirements so the longer-term effects of coordinated market implementation may be different from the estimated average rate impacts. Moreover, as explained above, a decision was made to not control for changes in factors such as regional gas costs that might be viewed as causally related to RTO implementation so, as a result, relative changes in regional gas costs that were in fact unrelated to RTO implementation could potentially impact the estimated coordinated market rate impact.

IV. GAS DEPENDENCE

The study methodology intentionally does not control for the current level of regional or individual utility gas dependence because of the suggestion in some discussions that implementation of coordinated markets foster reliance on gas-fired generation. A related question is whether the asserted relationship between coordinated market implementation and gas-fired generation dependence is supported by the data. Data on oil and gas dependence by state over the period 1990-2004 were gathered and summarized in tabular form below. Overall, the data do not show a relationship between changes in the fuel mix by state, and whether or not the state underwent a transition from a traditional to a coordinated market structure. It is striking that since 1997 the level of gas dependence has declined somewhat in the coordinated market states of Delaware, New Jersey and New York, while rising materially in traditional market structure states such as Alabama and Florida, as shown in Table 12.[30]

[30] As in Table 9 above, these percentages are based on the ratio of oil- and gas-fired generation output in megawatt hours to total state generation output in megawatt hours.

In other states that have maintained a traditional market structure, the increased reliance on gas-fired generation since 1997 has been relatively small. Identification of patterns is complicated by varying weather conditions from year to year, as gas use will be higher in years with particularly hot summers, since reliance on gas generation tends to be much higher than average for meeting incremental peak load.

Table 12
Oil- and Gas-Fired Generation as a Percentage of Total Generation
Mid-Atlantic and South, 1990-2004

YEAR	DE	MD	NJ	NY	FL	LA	MS	OK
1990	32.60%	15.40%	22.50%	41.80%	33.60%	51.90%	26.40%	38.90%
1991	38.40%	14.00%	29.30%	38.10%	36.10%	48.60%	23.60%	37.60%
1992	40.20%	9.30%	36.20%	35.90%	33.80%	51.80%	22.30%	32.90%
1993	39.20%	11.00%	35.20%	33.90%	36.50%	50.40%	27.80%	31.60%
1994	45.20%	12.00%	40.40%	35.10%	38.00%	51.40%	29.10%	33.50%
1995	49.50%	6.50%	44.20%	43.00%	38.90%	52.90%	33.70%	31.90%
1996	48.40%	5.30%	47.10%	34.70%	37.50%	49.20%	26.80%	28.60%
1997	42.10%	6.40%	42.50%	39.00%	39.20%	51.80%	25.80%	25.90%
1998	40.60%	10.70%	32.00%	39.60%	42.40%	52.70%	34.90%	32.60%
1999	56.20%	12.40%	31.50%	40.50%	42.90%	55.50%	34.30%	32.60%
2000	28.20%	10.20%	30.30%	39.60%	41.20%	51.90%	30.20%	31.60%
2001	48.20%	9.70%	30.30%	38.40%	44.10%	49.90%	42.80%	32.80%
2002	39.90%	9.30%	32.20%	35.80%	47.60%	52.40%	39.60%	35.70%
2003	43.00%	9.10%	28.40%	34.50%	49.60%	51.00%	27.70%	36.30%
2004	35.70%	8.60%	31.10%	35.10%	52.20%	50.60%	33.00%	38.50%

YEAR	PA	WV	AL	AR	GA	NC	SC	TN	VA
1990	4.30%	0.50%	1.50%	9.40%	1.30%	0.60%	1.30%	0.50%	4.90%
1991	3.60%	0.40%	1.60%	8.30%	1.40%	0.70%	1.70%	0.50%	7.50%
1992	3.00%	0.50%	1.70%	8.80%	1.60%	0.80%	0.60%	0.50%	7.70%
1993	4.90%	0.50%	1.50%	6.90%	1.80%	0.80%	0.50%	0.70%	11.20%
1994	5.40%	0.50%	1.50%	7.70%	1.60%	0.80%	0.80%	0.80%	12.20%
1995	4.60%	0.50%	1.60%	9.50%	2.10%	1.20%	1.20%	0.90%	11.20%
1996	3.50%	0.50%	1.80%	8.50%	2.00%	0.90%	0.60%	0.60%	7.80%
1997	2.80%	0.40%	2.00%	6.80%	2.00%	1.00%	0.80%	0.60%	6.80%
1998	4.40%	0.40%	3.50%	10.20%	4.20%	1.60%	1.50%	1.60%	9.90%
1999	3.80%	0.40%	3.00%	10.10%	4.10%	1.60%	1.60%	1.30%	10.80%
2000	3.20%	0.40%	4.30%	9.30%	4.70%	1.60%	1.50%	1.30%	9.80%
2001	3.40%	0.70%	8.00%	7.60%	4.30%	1.90%	1.70%	0.90%	13.00%
2002	4.60%	0.60%	12.20%	10.00%	6.40%	3.30%	5.00%	0.80%	10.90%
2003	4.90%	0.60%	9.20%	15.10%	4.40%	1.90%	2.30%	1.10%	13.80%
2004	6.50%	0.60%	11.90%	10.70%	5.60%	2.50%	4.80%	0.50%	14.60%

Source: http://.www.doc.gov/eneaf/electricity/epa/generation_state.xls

New England has historically had a high proportion of oil- and gas-fired generation. While the proportion of gas-fired generation has risen dramatically in Maine and New Hampshire since 1998, the overall proportion of gas-fired generation in New England has risen from about 35% to 46% between 1996 and 2004.[31]

Table 13
Oil- and Gas-Fired as a Percentage of Total Generation
New England, 1990-2004

YEAR	CT	MA	ME	NH	RI	VT	New England
1990	28.80%	53.30%	19.60%	18.90%	96.00%	1.30%	34.60%
1991	35.40%	54.80%	12.70%	11.20%	97.20%	1.90%	35.90%
1992	23.80%	55.40%	14.10%	9.70%	98.50%	1.40%	34.30%
1993	17.50%	55.70%	12.00%	8.10%	98.20%	0.60%	30.80%
1994	17.50%	56.50%	11.40%	11.40%	98.20%	0.20%	31.90%
1995	21.00%	54.10%	20.90%	8.20%	98.00%	0.40%	33.40%
1996	36.30%	48.60%	11.10%	5.30%	98.60%	0.10%	34.80%
1997	62.80%	56.60%	24.10%	7.00%	98.50%	0.20%	46.70%
1998	55.50%	57.30%	28.60%	9.20%	98.40%	0.90%	46.90%
1999	41.50%	55.10%	37.80%	10.20%	98.10%	0.80%	42.60%
2000	32.60%	50.30%	41.60%	4.10%	98.00%	2.40%	37.80%
2001	30.40%	52.50%	62.10%	4.00%	98.60%	0.80%	42.60%
2002	35.80%	54.00%	65.40%	5.50%	90.20%	0.20%	44.90%
2003	24.10%	61.80%	59.90%	28.80%	98.10%	0.40%	46.20%
2004	30.20%	60.00%	58.30%	30.80%	97.80%	0.40%	46.20%

Source: http://.www.doc.gov/eneaf/electricity/epa/generation_state.xls

[31] Data for 1997 and 1998 are affected by nuclear plant outages that raised reliance on oil- and gas-fired generation.

In the until-very-recently-traditional market regions in the Midwest, gas dependence has remained low throughout the 1990-2004 period, as shown in Table 14.[32]

Table 14
Oil and Gas-Fired Generation as a Percentage of Total Generation
Midwest, 1990-2004

YEAR	IA	IL	IN	KY	MI	MN	ND	NE	OH	SD	WI
1990	1.30%	1.40%	2.30%	0.20%	8.70%	2.30%	0.30%	1.50%	0.50%	0.30%	1.10%
1991	1.40%	2.00%	1.90%	0.20%	8.60%	3.30%	0.20%	1.40%	0.60%	0.30%	1.10%
1992	1.00%	1.70%	1.70%	0.10%	10.70%	3.20%	0.20%	0.70%	0.40%	0.10%	1.10%
1993	1.60%	2.00%	1.30%	0.10%	10.10%	2.60%	0.20%	0.80%	0.50%	0.40%	1.50%
1994	1.40%	3.50%	1.70%	0.20%	11.50%	2.90%	0.20%	1.30%	0.60%	0.40%	2.00%
1995	1.60%	3.30%	1.60%	0.20%	11.60%	3.40%	0.20%	1.10%	0.80%	0.90%	2.60%
1996	1.20%	2.50%	1.70%	0.30%	12.30%	3.20%	0.30%	0.80%	0.50%	0.60%	2.20%
1997	1.50%	3.60%	1.70%	0.30%	13.20%	3.70%	0.30%	0.90%	0.50%	1.00%	3.60%
1998	1.80%	4.60%	2.70%	1.10%	14.20%	4.70%	0.20%	1.60%	0.70%	2.60%	5.30%
1999	1.70%	3.30%	2.50%	0.60%	14.50%	4.40%	0.20%	1.30%	1.00%	1.90%	4.70%
2000	1.30%	3.00%	2.40%	0.70%	13.20%	3.40%	0.20%	1.70%	0.80%	3.20%	4.50%
2001	1.70%	3.40%	2.30%	0.80%	12.40%	3.80%	0.20%	1.20%	0.90%	4.80%	4.60%
2002	1.50%	4.90%	3.50%	4.80%	14.40%	4.30%	0.10%	1.40%	1.50%	1.20%	4.30%
2003	1.00%	2.70%	2.80%	3.70%	11.20%	4.90%	0.20%	1.40%	1.50%	2.40%	4.90%
2004	2.20%	2.20%	2.30%	4.40%	13.50%	4.40%	0.20%	1.00%	1.90%	1.80%	5.20%

Source: http://.www.doc.gov/eneaf/electricity/epa/generation_state.xls

32 Since gas generation is used to meet peak demand in the Midwest, there are year-to-year variations depending on weather patterns, such as the increase in 1998, presumably reflecting the high demand during the unusually hot summer.

Table 15 shows that there has been a substantial increase in gas dependence in the WECC since 1997, particularly in traditional market regions, such as Arizona, Oregon, Idaho, Colorado and Nevada. Reliance on oil- and gas-fired generation also increased materially in California since 1996-1998 (but less so relative to 1990-1994).[33]

Table 15
Oil and Gas-Fired Generation as a Percentage of Total Generation
WECC, 1990-2004

YEAR	AZ	CA	CO	ID	MT	NM	NV	OR	UT	WA	WY
1990	4.00%	48.00%	4.00%	0.60%	0.30%	9.60%	12.50%	1.70%	0.60%	0.30%	0.80%
1991	3.50%	47.80%	4.20%	1.10%	0.20%	11.50%	10.60%	2.60%	2.00%	0.50%	1.00%
1992	4.40%	51.20%	4.20%	1.90%	0.20%	8.70%	15.90%	3.60%	2.00%	1.50%	0.90%
1993	3.00%	44.50%	4.40%	1.50%	0.20%	10.20%	18.60%	4.30%	1.90%	3.70%	1.10%
1994	3.70%	52.50%	6.50%	1.80%	0.40%	11.20%	23.60%	7.40%	2.40%	5.50%	1.10%
1995	3.30%	41.30%	8.10%	1.40%	0.80%	11.50%	27.00%	5.20%	2.50%	5.00%	1.00%
1996	3.10%	38.40%	8.70%	1.20%	1.90%	11.90%	28.10%	7.50%	1.10%	4.10%	1.10%
1997	3.20%	42.30%	8.70%	2.10%	1.70%	13.10%	28.10%	6.90%	1.10%	2.60%	1.10%
1998	4.90%	40.80%	10.30%	2.40%	1.70%	14.00%	28.60%	14.20%	1.60%	4.30%	0.90%
1999	6.10%	46.30%	12.70%	2.30%	1.70%	12.90%	30.70%	12.10%	1.70%	3.20%	1.00%
2000	10.00%	51.00%	16.50%	2.60%	2.10%	13.90%	35.90%	17.70%	2.60%	7.60%	1.30%
2001	14.70%	57.90%	20.40%	15.10%	2.10%	14.70%	36.70%	24.60%	4.20%	11.70%	1.40%
2002	18.40%	49.70%	19.80%	3.40%	1.90%	11.30%	38.10%	16.60%	3.90%	4.70%	1.70%
2003	20.10%	48.70%	19.90%	13.20%	1.60%	10.90%	40.00%	21.00%	3.70%	7.10%	0.70%
2004	27.10%	52.70%	22.50%	15.70%	1.80%	9.20%	43.80%	26.40%	2.50%	8.40%	0.30%

Source: http://.www.doc.gov/eneaf/electricity/epa/generation_state.xls

[33] Aside from the long-term trend there are also year to year variations reflecting changes in hydro conditions, such as the general increase in reliance on oil- and gas-fired generation during 2000-2001, reflecting the low hydro conditions during most months of those years.

We have not undertaken a detailed analysis of changes in resource mix but it appears that the decline in dependence on gas-fired generation in New York and Eastern PJM is attributable in part to markedly higher and more stable nuclear plant output following the implementation of coordinated markets as shown in Table 16. Annual nuclear generation output in New York and PJM rose 28% between 1997 and 2004. Indeed, nuclear plant output was higher in every year 2001 through 2004, than in any prior year. No new nuclear plants were placed in operation; the increased output reflects improved operating performance and minor output raising operational improvements.

Table 16
Nuclear Generation in PJM and NYISO
Megawatt Hours, 1990-2004

YEAR	MD	NJ	NY	PA	Total
1990	1,251,416	23,770,387	23,623,356	57,787,051	106,432,210
1991	9,036,100	24,806,606	28,448,293	57,475,671	119,766,670
1992	10,663,950	21,595,097	24,154,932	60,132,729	116,546,708
1993	12,300,816	24,932,240	26,889,261	59,330,534	123,452,851
1994	11,235,408	22,129,335	29,231,434	67,206,815	129,802,992
1995	12,937,971	16,805,517	26,336,172	66,461,535	122,541,195
1996	12,092,768	11,027,886	35,225,806	68,672,038	127,018,498
1997	13,212,967	13,908,074	29,569,618	67,654,588	124,345,247
1998	13,330,598	27,132,139	31,313,708	61,149,224	132,925,669
1999	13,312,335	28,970,893	37,018,540	71,127,449	150,429,217
2000	13,827,243	28,578,119	31,507,988	73,771,347	147,684,697
2001	13,656,267	30,469,230	40,394,985	73,730,797	158,251,279
2002	12,128,005	30,865,675	39,617,491	76,088,930	158,700,101
2003	13,690,713	29,709,201	40,679,205	74,360,862	158,439,981
2004	14,580,260	27,081,566	40,640,305	77,458,632	159,760,763

Source: http://.www.doc.gov/eneaf/electricity/epa/generation_state.xls

Improved nuclear plant performance is not limited to plants located in the New York and PJM coordinated market regions. Table 17 shows that nuclear plant output also rose substantially over this period in the traditional market states in the Southeast; however, the increase in nuclear plant output over the period 1997-2004 was only 15% in these states.

Table 17
Nuclear Generation in the Southeast
Megawatt Hours, 1990-2004

YEAR	AL	AR	FL	GA	MS	NC	SC	Total
1990	12,051,882	11,282,053	21,779,560	24,796,884	7,422,131	25,905,319	42,880,669	146,120,488.00
1991	15,874,637	12,661,793	20,507,569	26,016,023	9,132,933	30,312,425	43,108,073	157,615,444.00
1992	19,397,436	11,325,661	25,115,956	27,996,298	8,173,763	22,753,813	45,536,530	160,301,449.00
1993	17,823,325	13,521,676	25,886,864	27,233,352	7,903,547	23,758,927	46,188,884	162,318,568.00
1994	20,479,759	13,923,701	26,682,107	28,927,090	9,614,699	32,346,007	44,466,176	176,441,533.00
1995	20,752,341	11,657,549	28,740,617	30,660,626	8,013,321	35,910,195	49,173,476	184,910,120.00
1996	29,707,535	13,356,671	25,470,291	29,925,001	9,224,593	33,718,182	43,571,032	184,975,301.00
1997	29,572,670	14,208,157	22,967,743	30,414,494	10,812,562	32,453,074	44,915,514	185,346,211.00
1998	28,662,513	13,097,252	31,115,419	31,380,401	9,190,528	38,778,211	48,759,447	200,985,769.00
1999	30,892,394	12,919,550	31,526,285	31,478,122	8,428,216	37,523,504	50,813,559	203,583,629.00
2000	31,368,563	11,651,772	32,291,345	32,472,935	10,694,555	39,126,881	50,887,700	208,495,751.00
2001	30,357,063	14,780,789	31,583,404	33,681,769	9,923,882	37,775,025	49,869,998	207,973,931.00
2002	31,856,926	14,558,884	33,704,230	31,107,735	10,059,459	39,626,849	53,325,854	214,241,939.00
2003	31,676,953	14,689,416	30,979,481	33,256,649	10,902,456	40,906,900	50,417,690	212,831,548.00
2004	31,635,789	15,449,851	31,215,576	33,747,705	10,232,766	40,090,623	51,200,640	213,574,954.00

Source: http://.www.doc.gov/eneaf/electricity/epa/generation_state.xls

Nuclear generation in the WECC has remained under utility ownership and there has been a modest increase in output since 1990.

Table 18
Nuclear Generation in WECC
Megawatt Hours, 1990-2004

YEAR	AZ	CA	WA	Total
1990	20,597,689	32,692,807	5,742,027	59,032,523
1991	25,095,776	31,541,799	4,229,868	60,867,443
1992	25,608,706	35,244,336	5,692,379	66,545,421
1993	22,048,880	31,580,692	7,134,966	60,764,538
1994	23,170,894	33,752,237	6,739,749	63,662,880
1995	26,984,507	30,245,936	6,941,878	64,172,321
1996	28,839,587	34,096,860	5,588,000	68,524,447
1997	29,314,200	30,512,118	6,244,135	66,070,453
1998	30,301,045	34,594,206	6,916,065	71,811,316
1999	30,415,572	33,371,857	6,085,893	69,873,322
2000	30,380,571	35,175,505	8,605,232	74,161,308
2001	28,724,076	33,219,520	8,250,429	70,194,025
2002	30,861,911	34,352,340	9,048,475	74,262,726
2003	28,581,053	35,593,789	7,614,708	71,789,550
2004	28,112,609	30,267,887	8,981,583	67,362,079

Source: http://.www.doc.gov/eneaf/electricity/epa/generation_state.xls

V. CONCLUSIONS

The overall conclusion of this study is that the implementation of coordinated markets has served to reduce average residential rates in the regions in which coordinated markets have been in place for several years, relative to the average rates that would otherwise have prevailed. Rather than estimating a single model, several different models have been estimated. All of the models yielded estimates of reductions in average retail rates arising from implementation of coordinated markets of $.50 per megawatt hour or more; some provided estimated savings in excess of $1.80 per megawatt hour, while a number produced estimated savings in the range of $1.50 per megawatt hour.

These average consumer rates include all market costs – energy, ancillary services, capacity market, etc., and all charges for RTO cost recovery, as well as the bulk of FERC operating costs, which are recovered through charges imposed on RTOs and their customers. As a result, the estimated rate savings are the net benefits of RTO operation (i.e., gross benefits less RTO operating costs). Because RTO costs are recovered from market participants, the amount by which utility rates have been reduced in regions implementing coordinated markets is the amount by which RTO cost reductions have exceeded RTO costs. While there is a range of estimates of coordinated market impacts, even the lower end of the range of estimated impacts imply very large net benefits. For average PJM and NYISO load of around 100,000 MW per hour, a cost saving of even $.50 per megawatt hour amounts to $1.2 million per day and $430 million a year. A cost saving of $1.5 per megawatt hour would similarly amount to savings of around $1.3 billion per year. Moreover, as noted above, the estimated cost savings are net of the costs of operating the RTOs and FERC costs, so these estimates imply annual consumer savings in these regions in the billions of dollars.

Power prices have in general risen since 1997 but this rise has taken place in regions in which coordinated markets have been implemented as well as in regions in which they have not been implemented. The impact of rising fuel prices on average consumer power rates cannot be avoided through changes in power market structure. The evidence that implementation of coordinated markets tends to reduce average consumer rates does not lessen concerns regarding the upward trend in power prices, but indicates that it is necessary to address the underlying cause of rising fuel costs.

Evidence that implementation of coordinated markets tends to reduce consumer rates does not lessen the importance of efficiency in RTO operations. Nor do these results imply that there is no need to develop better resource adequacy mechanisms, to improve the availability of long-term transmission congestion hedges for entities seeking such hedges, or to improve price signals during scarcity conditions within the PJM or NYISO coordinated markets. The point of the results is that even if current RTO market designs and implementation are imperfect, the historical data is consistent with the view that implementation of coordinated markets has provided material benefits to consumers, net of incremental RTO costs.

Appendix A

Data Used in the Analysis of Average Retail Rate Trends

This study analyzes the average rate history of four broad groups of munis and coops: those located in NYISO/NYPP; in Classic PJM (PJM as of 1998, i.e., excluding recently added control areas);[34] in the Allegheny control area that became part of PJM in 2002, and munis and coops in non-coordinated markets located in Alabama, Arkansas, Florida, Georgia, North Carolina and South Carolina, except for munis that are served by TVA. The selection of munis and coops for the study is based on information obtained from EIA form 861 for the years 1990-2004; this form is filed by both investor-owned and publicly-owned electric utilities.[35] EIA-861 reports the utility location (NERC region and control area operator), mailing address and information concerning the utility sales (revenue and MWh sales, by customer class).

Munis and coops within the relevant geographic regions are included in the study sample if they had residential electric sales in each year of the 1990-2004 study period. In most cases, the determination of the geographic classification for each muni or coop was straightforward, but there were some kinds of inconsistent reporting in the EIA 861 that had to be addressed in order to determine whether or not to include a muni or coop in the study.

In particular, assignment of munis and coops to Classic PJM or Allegheny Power was based on review of transmission owner Form 1s and consultations with PJM. Since both Allegheny Power and several classic PJM transmission owners sold power to Allegheny Electric Cooperative, which, in turn, sold power to individual electric cooperatives, the Form 1 and PJM data are not dispositive as to which individual electric cooperatives were served by power withdrawn from the PJM or Allegheny grids. This classification was based on cooperative maps and advice from PJM but may not be completely accurate. In particular, Allegheny Electric Cooperative may have been able to deliver power to some of its cooperatives from both the PJM and Allegheny grids. Ultimately, the utilities in question were assigned to Classic PJM and Allegheny Power, as follows.

Munis and coops assigned to Classic PJM.

- In PA: Borough of Berlin, Borough of Blakely, Borough of Catawissa, Borough of Duncannon, Borough of East Conemaugh, Borough of Ephrata, Borough of Girard, Borough of Goldsboro, Borough of Hatfield, Borough of Hooversville Electric & Light, Borough of Kutztown, Borough of Lansdale, Borough of Lehighton, Borough of Lewisberry, Borough of Middletown, Borough of Mifflinburg, Borough of Olyphant, Borough of Perkasie, Borough of Quakertown, Borough of Royalton, Borough of Schuylkill Haven, Borough of

[34] A sensitivity scenario includes munis and coops contained in the Allegheny Power control area, which joined PJM in 2002.

[35] Form 861 data for 2005 will not be available until November or December 2006.

Smethport, Borough of St. Clair, Borough of Summerhill, Borough of Watsontown, Borough of Weatherly, Adams Electric Coop, Bedford REA, Claverack REA, New Enterprise REA, Northwestern REA, Southwest Central REA, Sullivan County REA, United Electric Coop and Warren Electric Coop.

- In MD: Choptank Electric Coop, Southern Maryland Electric Coop, Town of Berlin and Easton Utilities.

Munis and coops assigned to Allegheny Power:

- In PA: Borough of Chambersburg, Borough of Mont Alto, Central Electric Coop, Somerset REA, Tri-County REA and Valley Rural Electric Coop.
- In MD: City of Hagerstown, Thurmont Municipal Light and Town of Williamsport.
- In WV: Harrison REA, City of New Martinsville and Phillipi Municipal Electric.
- In VA: Town of Front Royal.

Other issues with the identification of munis and coops for the study, and other adjustments to the sample data include the following.

City of Tarentum, PA is reported as a MAAC muni with a blank control area in 1999, which is the first year in which it filed. Tarentum is excluded from the sample because there is no EIA 861 data available prior to 1999.

City of Zelienope, PA is reported in the MAAC council in the Ohio Edison control area for 1995-1997. It reports itself as being in the ECAR council in the other years. Zelienope is excluded from the sample.

City of New Wilmington, PA is reported as a MAAC muni from 1995-2000, and thereafter has no more EIA-861 reports. New Wilmington is excluded from the sample.

Haywood Electric Member Coop has residential sales in NC and GA over the 1990-2004 period but reports sales to residential customers in SC from 1999-2004. Haywood sales to SC residential customers are excluded in the study.

Mecklenburg Electric Coop reports residential sales for NC in 2002-2004. Since there are no data for Mecklenburg residential sales in NC prior to 2002, Mecklenburg is excluded from the sample.

Four entities located in Georgia and NC are excluded because they are TVA munis and coops: Blue Ridge Mountain E.M.C. (GA/NC), City of Chickamauga (GA), North Georgia Electric Member Coop (GA) and Tri-State Electric Member Corp (GA/NC). One additional entity in NC is excluded because it is a TVA muni: City of Murphy.

Allegheny Electric Coop, PA, City of Gouverneur, NY and City of Watertown, NY make only wholesale sales of electricity and do not serve residential customers. Therefore, these entities are excluded from the sample.

LIPA, NY is a non-profit muni. Prior to May 1998, its predecessor, LILCO was an investor-owned utility. LIPA is excluded from the sample

A&N Electric has sales in both MD and VA but lists its mailing address as VA. Both A&N's MD and VA sales are included in the sample.

Davidson Electric and Crescent Electric, NC merged in 1998 to become Energy United Electric. Residential sales of these entities for 1990-1997 are combined to reflect the merger in 1998, so that a single combined entity is represented in all years of the study.

City of St. Cloud, FL reached an agreement with the Orlando Utilities Commission (OUC) in 1997 to have OUC provide service to its customers. The residential sales of the City of St. Cloud are added to those for OUC for 1990-1997 to reflect this agreement.

New Enterprise REC, PA had typos in the state ID field, listing it as in MA instead of PA. New Enterprise is included in the sample as a PJM muni.

Southern Maryland Coop has multiple data points for some years. These multiple data points are combined for one data point per year.

City of Jamestown, NY has multiple data points for some years. These multiple data points are combined for one data point per year.

Finally, we reviewed the EIA-861 data for anomalous values and identified a number of instances of large year-to-year rate changes and large changes in industrial sales proportions. Some of these anomalies are associated with significant residuals in the econometric analysis and could reflect reporting or posting errors or could be accurate.[36] We reran the models dropping a few utilities with particularly large outliers. In some models, this caused the estimated coordinated market impact to be smaller (less negative) and less statistically different from zero and in other cases this caused the estimated coordinated market rate impact to increase (become more negative) and to be statistically different from zero at higher confidence levels. Lacking a reliable basis for determining whether any of these anomalies reflect data errors rather than actual rate impacts, we have reported only the estimates based on all of the data.

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36 For example, industrial sales' values that drop from substantial proportions of total sales could reflect data errors, such as missing data, but they also could reflect the effects of plant shutdowns or cogeneration.

Appendix B

Detailed Econometric Results

Table B-1
Utility Dummy Model

Coefficient Estimate Summary			
	East Coast Gas Region	**Non-Gas Region**	**Non-Gas Region + Allegheny**
Coordinated Market	-1.621	-.879	-.803
t-statistic	2.62	1.41	1.30
APS Region	NA	NA	.708
t-statistic			.50
Total Sales	-.0000044	-.0000034	-.0000034
t-statistic	4.96	4.82	4.90
Average Residential Load	-1.496	-2.91	-2.87
t-statistic	9.75	28.8	28.81
Proportion Industrial Load	-8.95	4.35	4.77
t-statistic	4.37	2.72	3.06
Constant = 1990	105.65	120.36	119.71
1991	0.76	2.81	2.81
1992	1.11	4.22	4.28
1993	3.31	7.01	7.04
1994	3.17	6.86	7.04
1995	3.92	8.47	8.61
1996	4.01	8.54	8.72
1997	4.06	7.72	7.93
1998	4.47	8.84	8.90
1999	4.33	8.74	8.81
2000	7.15	9.76	9.71
2001	11.14	10.36	10.32
2002	10.96	12.82	12.74
2003	14.09	14.65	14.70
2004	16.71	16.98	17.06
R^2	0.947	0.843	0.853
N	1830	4995	5190

Table B-2
1990 Rate Model

Coefficient Estimate Summary			
	East Coast Gas Region	**Non-Gas Region**	**Non-Gas Region + APS**
Coordinated Market	-1.415	-1.87	-1.474
t-statistic	2.01	2.61	2.08
APS Region			-.297
t-statistic			.016
1990 rate	.879	.788	.793
	100.25	73.26	80.00
Total Sales	-.00000012	-.0000012	-.00000124
t-statistic	.62	5.15	5.53
Average Residential Load	-.592	-1.36	-1.258
t-statistic	7.97	20.35	19.65
Proportion Industrial Load	.017	-2.46	-2.27
t-statistic	.02	3.50	3.28
Constant = 1990	14.30	31.59	29.98
1991	.76	2.66	2.65
1992	1.00	4.35	4.40
1993	2.86	6.12	6.13
1994	2.46	6.35	6.51
1995	3.04	7.43	7.54
1996	2.76	6.87	7.02
1997	3.03	6.82	7.01
1998	2.99	6.84	6.86
1999	2.77	7.08	7.06
2000	5.07	7.47	7.32
2001	8.93	8.30	8.07
2002	8.32	9.90	9.77
2003	11.02	12.04	12.04
2004	13.77	13.90	13.92
R^2	.892	.631	.656
N	1830	4995	5190

Appendix C

Adjustments for Heteroskedasticity

Table C-1
Utility Dummy Model
White Robust Standard Errors

Coefficient Estimate Summary			
	East Coast Gas Region	**Non-Gas Region**	**Non-Gas Region + Allegheny**
Coordinated Market	-1.621	-.879	-.803
t-statistic	2.60	1.36	1.25
APS Region	NA	NA	.708
t-statistic			.49
Total Sales	-.0000044	-.0000034	-.0000034
t-statistic	7.55	5.15	5.18
Average Residential Load	-1.496	-2.91	-2.87
t-statistic	4.08	9.81	9.88
Proportion Industrial Load	-8.95	4.35	4.77
t-statistic	4.27	2.05	2.31

Table C-2
1990 Rate Model
White Robust Standard Errors

Coefficient Estimate Summary			
	East Coast Gas Region	**Non-Gas Region**	**Non-Gas Region + APS**
Coordinated Market	-1.415	-1.87	-1.474
t-statistic	1.65	2.10	1.67
APS Region			-.297
t-statistic			.016
1990 rate	.879	.788	.793
t-statistic	91.78	60.01	66.46
Total Sales	-.00000012	-.0000012	-.00000124
t-statistic	.92	5.12	5.21
Average Residential Load	-.592	-1.36	-1.258
t-statistic	7.41	13.42	13.23
Proportion Industrial Load	.017	-2.46	-2.27
t-statistic	.02	3.58	3.38

Table C-3
Utility Dummy Model

Coefficient Estimate Summary			
	East Coast Gas Region	**Non-Gas Region**	**Non-Gas Region + Allegheny**
Coordinated Market	-1.59	-.721	-.646
t-statistic	2.57	1.15	1.04
APS Region			.610
t-statistic			.45
Total Sales	-.00000044	-.0000027	-.0000027
t-statistic	5.08	5.09	5.14
Average Residential Load	-1.495	-2.696	-2.671
t-statistic	9.74	27.32	27.36
Proportion Industrial Load	-9.028	3.50	3.885
t-statistic	4.41	2.36	2.67
Constant = 1990	105.547	117.449	117.020
1991	.772	2.569	2.578
1992	1.108	4.070	4.134
1993	3.314	6.702	6.733
1994	3.164	6.539	6.697
1995	3.900	7.921	8.069
1996	4.000	7.864	8.065
1997	4.070	7.028	7.243
1998	4.468	8.151	8.219
1999	4.322	8.149	8.214
2000	7.109	9.189	9.144
2001	11.125	9.938	9.897
2002	10.936	12.134	12.072
1	14.069	13.867	13.925
2004	16.713	15.936	16.043
n	1830	4995	5190

Table C-4
1990 Rate Model

Coefficient Estimate Summary			
	East Coast Gas Region	**Non-Gas Region**	**Non-Gas Region + APS**
Coordinated Market	-1.392	-.917	-.570
t-statistic	1.99	1.27	.80
APS Region			-.801
t-statistic			.46
1990 rate	.878	.796	.800
t-statistic	100.12	76.89	83.44
Total Sales	-.00000012	-.00000086	-.00000091
t-statistic	.65	5.01	5.35
Average Residential Load	-.592	-1.283	-1.194
t-statistic	7.97	20.27	19.61
Proportion Industrial Load	.0189	-2.822	-2.685
t-statistic	.02	4.36	4.21
Constant = 1990	14.342	30.382	28.927
1991	.768	2.456	2.452
1992	.996	4.187	4.242
1993	2.857	5.855	5.871
1994	2.454	6.059	6.202
1995	3.029	6.916	7.037
1996	2.747	6.261	6.417
1997	3.026	6.119	6.318
1998	2.980	6.137	6.170
1999	2.752	6.447	6.445
2000	5.034	6.874	6.762
2001	8.909	7.721	7.606
2002	8.287	9.266	9.153
2003	10.997	11.277	11.287
2004	13.745	12.913	12.961
n	1830	4995	5190