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

Scott M. Harvey, Bruce M. McConihe and Susan L. Pope

Center for Research in Regulated Industries
Rutgers University

20th Annual Western Conference
Monterey, California

November 20, 2006 (Revised June 18, 2007)

LECG

Table of Contents

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

Scott M. Harvey, Bruce M. McConihe and Susan L. Pope
November 20, 2006 (Revised June 18, 2007)

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. The policy question we address 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.

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.

Electricity rates have increased since LMP-based coordinated markets were first implemented in PJM in 1998, but this study finds that the average rates of public utilities have risen less over this period 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 of $.50/MWh projects to $1.2 million per day and $430 million in total savings over a year, while the 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. The average consumer rates analyzed in this study reflect all market costs borne by the public utilities, including energy, ancillary services, capacity market, 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). Because the study methodology is based on consumer rates, which include the expense of operating RTOs, the estimated cost savings are net of the costs of operating the RTOs. The study results therefore imply 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. 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.

In this revision of our original paper, we have examined a large number of sensitivity cases that take account of comments on our original study. We find that the benefits estimated using these alternative specifications are in the same range as reported in our original paper and on balance probably suggest larger benefits than the estimates reported in the original paper. We think it is significant that we find, over a variety of models applied to multiple regions, that the estimated net benefits from the implementation of LMP-based coordinated markets are consistently positive and often, but not always, statistically different from zero at conventional confidence intervals.

We believe that this analysis reinforces the conclusions of other studies comparing prices in regulated and non-regulated areas and adds to the body of evidence demonstrating the benefits of wholesale competitive markets. It is intended that this analysis will sharpen the discussion of the merits of wholesale electricity market deregulation and implementation of regional wholesale markets based on LMP pricing. To assess the impact of the implementation of LMP-based coordinated markets on consumer rates, it is necessary 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.

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

Scott M. Harvey, Bruce M. McConihe and Susan L. Pope[1]
November 20, 2006 (Revised June 18, 2007)

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.

---

[1] Scott M. Harvey (sharvey@lecg.com) is a Director at LECG; Bruce M. McConihe (bmcconihe@aol.com) is a Director at Markets Consulting LLC. Susan L. Pope (spope@lecg.com) is a Principal at LECG. This research was supported by PJM, LLC. The authors are or have been consultants on electricity market design and transmission pricing, market power or generation valuation for Allegheny Energy Global Markets; AmerGen Energy; American Electric Power Service; American National Power; American Ref-Fuel; Atlantic City Electric Company; Australian Gas Light Co.; California ISO; Calpine Corporation; Centerpoint Energy; Commonwealth Edison; Central and South West; Constellation Power Source; Coral Power; Covanta Energy; Delmarva Power & Light; Dynegy; Edison Electric Institute; Edison Mission; Entergy; Entergy Nuclear Generation; EPCOR Power Development; FPL; FPL Energy; General Electric Capital; GPU; GPU Power Net Pty Ltd; GWF Energy; Independent Energy Producers Association; ISO New England; Longview Power; Midwest ISO; Morgan Stanley Capital Group; New England Power; New York Energy Association; New York ISO; New York Power Pool; Northeast Energy Associates; NRG; Ontario IMO and IESO; Pacific Gas & Electric; PECO Energy; PEPCO Energy; PJM; PJM Supporting Companies; POSDEF Power; PP&L Energy Plus; Public Service Electric and Gas; Reliant Energy; San Diego Gas & Electric; Sempra Energy; SETRANS; Mirant/Southern Energy; Texas Utilities; Transpower of New Zealand Ltd; UAE Mecklenburg Cogen; Westbook Power; Virginia Power; Williams Energy Group; and Wisconsin Electric Power Company. This paper has benefited from comments from the American Public Power Association, Joe Cavicchi, Steve Corneli, William Hogan, Laurence Kirsch, John Kwoka, Mathew Morey, and Howard Spinner. The views presented here are not necessarily attributable to any of those mentioned, and any errors are solely the responsibility of the authors. Arun Sharma, Alex Oliphant, Alexis Maharam and Ifrahn Siddique provided research assistance. The data used in the empirical analysis of retail rates is posted at http://www.lecg.com/website/home.nsf/OpenPage/Energy-ResearchPapersTestimony under Electricity Restructure and Market Design/Data Files for Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charge, June 15, 2007.

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.[2] The policy question we address is 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 between the retail market prices of utilities operating in regions with coordinated electricity markets and those of utilities operating in regions with a traditional regulatory framework.

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. 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 whose rates also reflect changes in the cost of meeting load. 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.

The study 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

---

[2] In this paper, the term "coordinated market" refers to LMP-based wholesale markets in which power is bought and sold at market-clearing prices, congestion charges can be hedged with financial transmission rights, and market participants able to respond to real-time dispatch instructions can choose to be dispatched by the system operator. It is important to recognize that implementation of coordinated markets is not the same as implementation of retail access programs under which the regulated distribution company no longer has an obligation to serve and therefore no longer hedges the power costs of retail consumers. The Electricity Consumers Resource Council, for example, questions the benefits of the "Day-Two Market construct," and "RTO platform with locational pricing," citing a comparison of Allegheny Energy retail rates in West Virginia versus Maryland (see Elcon, Supplemental Comments in FERC Docket AD07-7-000, pp. 2, 7-9). Allegheny Energy's West Virginia and Maryland load are both located within PJM's coordinated market and joined PJM at exactly the same time. Any difference in retail rates between Allegheny Energy customers in Maryland and West Virginia therefore cannot possibly be attributable to the implementation of coordinated markets, the "RTO platform" or "locational pricing."

utilities located both in regions that implemented coordinated markets and in regions that did not. 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. 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 an LMP-based 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.[3] 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[4] 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.

Average electricity rates have increased since LMP-based coordinated markets were first implemented in PJM in 1998, but this 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 of around

---

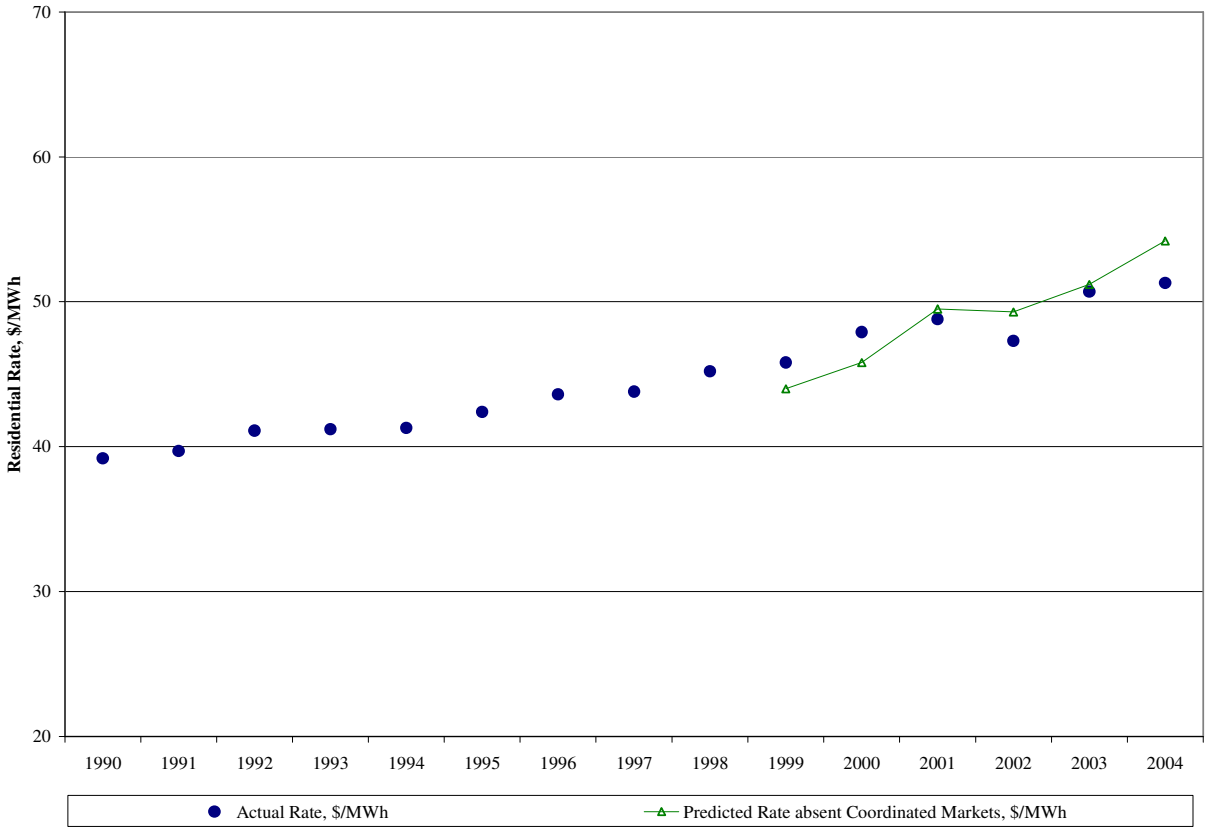
[3] As discussed in greater detail below, gas dependence is defined based on 1990 generation patterns so that this classification is independent of subsequent RTO implementation.

[4] 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, but became part of PJM on April 1, 2002.

$2.00 per megawatt hour, and a number produced estimated savings in the range of $1.50 per megawatt hour.

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 based on one of the models estimated. 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.[5]

Figure 1
Actual and Predicted Residential Rates of Public Utilities
Utility Dummy Model: NYISO



[5] 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. This affects the r^2 of the model, the proportion of historic variations explained by the model, but does not impact the validity of the estimate of the impact of implementing coordinated markets, as this does not depend on the r^2. 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 of Public Utilities
Utility Dummy Model: Eastern PJM (New Jersey, Delaware, Eastern Maryland)

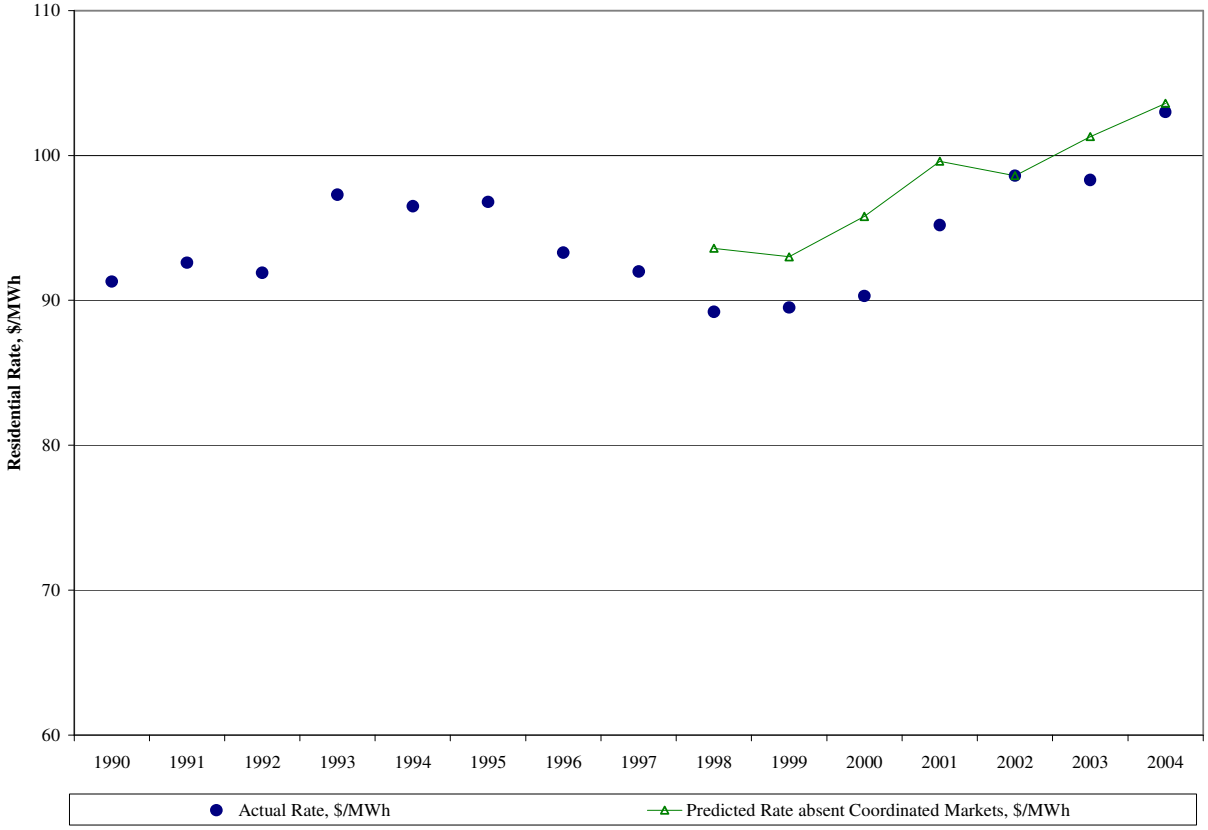
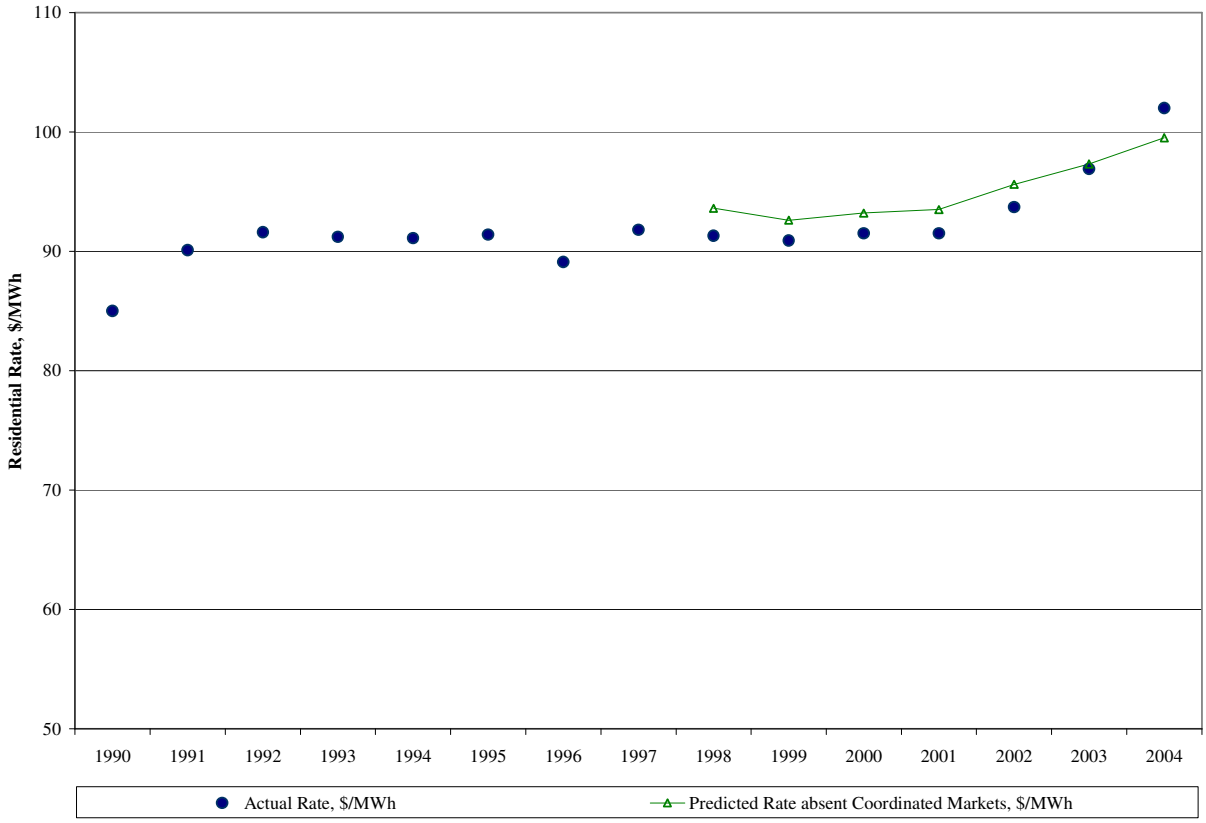


Figure 3 portrays the actual average rate of municipal and cooperative utilities in the non-gas dependent PJM state of Pennsylvania[6] over the period 1990-2004 and the projected rate, absent implementation of a coordinated market. It is apparent that the actual average rate is generally lower than the predicted rate over the period 1998-2004.

Figure 3
Actual and Predicted Residential Rates of Public Utilities
Utility Dummy Model: PJM-Pennsylvania



In focusing on a comparison of electricity rates in regions with coordinated markets to "what rates would otherwise have been" in these markets, it is intended that this paper will sharpen the discussion of the merits of wholesale electricity market deregulation and implementation of regional wholesale markets based on LMP pricing. To assess the impact of the implementation of LMP-based coordinated markets on consumer rates, it is necessary 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.

---

6 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.[7] 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 period 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 a before-and-after approach to measuring the benefits from the implementation of coordinated markets is that the state of New York and many of the states comprising PJM 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 retail access, 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. In particular, since reductions in forward hedging will tend to raise rates when power prices are rising and reduce rates when power prices are falling, unless changes in the level of forward hedging are somehow controlled for or the effects of implementing coordinated markets analyzed over a long period with many cycles of high and low power prices, it will not be possible to accurately identify the impact of implementing coordinated markets by analyzing the rates of customers subject to retail access. Some of the complications are:

- Should the rate comparison be based on provider of last resort prices or competitive retailer prices?

---

[7] This analysis of consumer rate impacts is not the same as a cost benefit analysis. It would be possible for a change in market design to reduce consumer rates yet not produce overall social benefits. This would be the case, for example, if consumer costs fell but producer profits fell more.

- Should the rate comparison include or exclude stranded cost recovery charges?
- How should such a rate comparison account for short-term caps on provider of last resort rates?
- How should such a rate comparison control for changes in the degree of forward hedging following the implementation of retail access?

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 that 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 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 (such as dependence on interstate pipelines for gas supply) across states and regions that can affect changes in 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 New York and the states belonging to PJM 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 would be to estimate the underlying cost reductions arising from the implementation of coordinated markets. While this approach could identify substantial inefficiencies in regions lacking coordinated markets, such as under-utilization of the transmission system,[8] the lack of transparent spot prices in the regions lacking coordinated markets would make it difficult to assign dollar magnitudes to such inefficiencies. Moreover, the methodology would be extremely resource-intensive if applied to all transmission constraints over a broad region over a meaningful period of time.[9] Such an approach could be very useful in identifying examples of the kind of inefficiencies that exist in regions lacking coordinated markets but it would be difficult to use this methodology to develop estimates of the overall benefits from implementation of coordinated markets. In addition, this approach also would require 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 (i.e., above those that

---

[8] 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.

[9] 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, but the inefficiency in traditional markets is inherently difficult to reproduce in simulation models based on optimization.

would be required to manage a traditional market) would not be 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 Office of the Interconnection and New York Power Pool had coordinated markets not been implemented. The implementation of coordinated markets changed the system control costs of the utilities in those regions, which would need 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 rates of implementing coordinated electricity markets while controlling for the impact of changes in fuel prices, the effects on rate design and utility forward hedging of state retail access programs, and differences in gas dependence among utilities. 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. Fuel prices have risen relatively sharply since the implementation of coordinated markets in PJM and New York, and 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 (in particular, changes in forward hedging) from the retail rate impacts of implementing coordinated markets.[10] 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

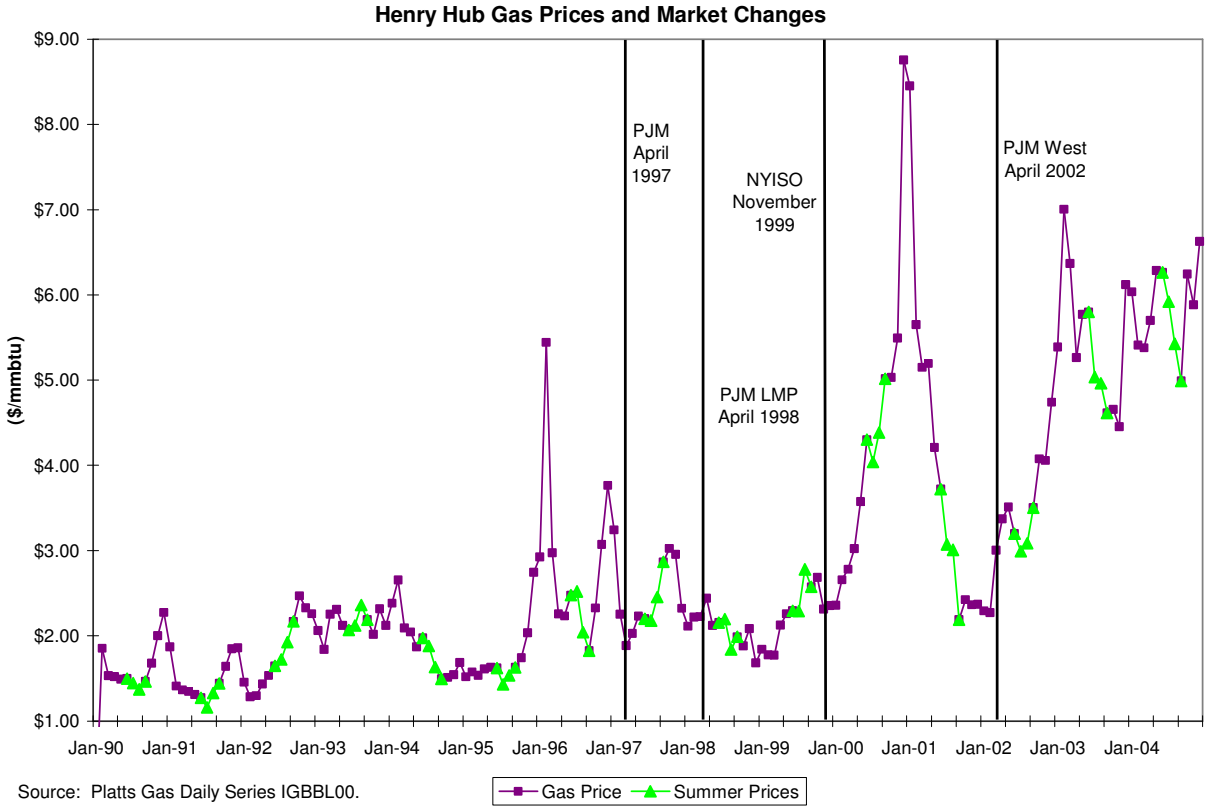
The first methodological hurdle – distinguishing the retail rate impact of market coordination from the rate impact of cost changes, particularly increasing fuel prices – has been addressed through the use of a combined cross section and time series model. The policy question

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

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.

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.[11]

Figure 4
Monthly Henry Hub Gas Prices and Market Changes



Source: Platts Gas Daily Series IGBBL00.

[11] APPA, for example, recently observed that "when seven members of the Blue Ridge Power Agency in Danville, VA signed new power supply contracts after PJM took over operations in their region, their wholesale power costs rose 100% in two years." American Public Power Association, "Statement of the American Public Power Association," December 1, 2006 (hereafter "APPA Statement"). Instances like this reveal the increase in power costs that has occurred in recent years, but do not inform us as to whether the power costs of these utilities would have risen less or more absent the implementation of coordinated markets in their region.

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 reflect 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 sustained rate impact or a short-term variation arising from transitory timing differences, such as the expiration dates of power or fuel contracts, the timing of rate changes or pass-through provisions.

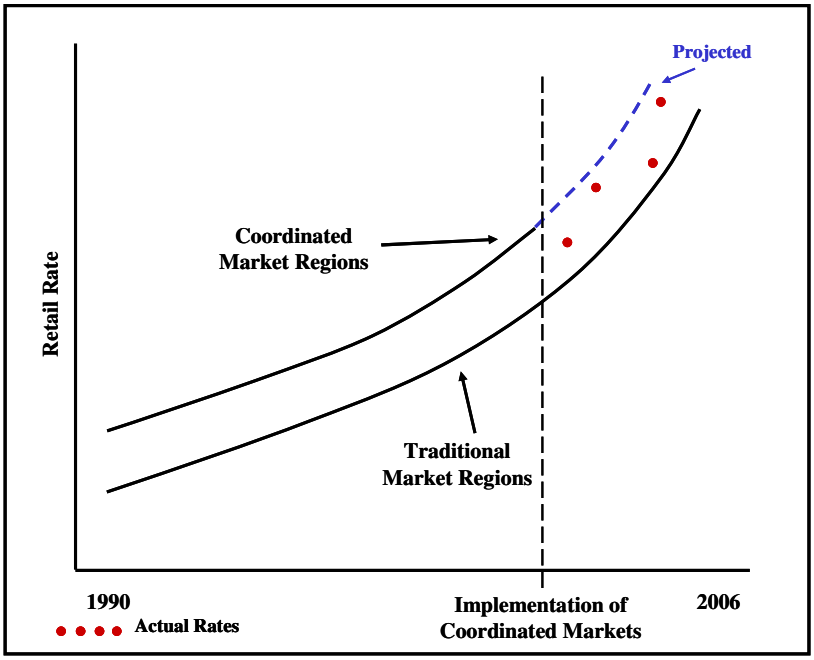
The use of a pooled time series-cross section model based on annual time-series data for both utilities in organized markets and utilities operating in traditional markets over the period 1990-2004[12] enables the study to distinguish how the implementation of coordinated markets changed the trajectory 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.[13] The effect of coordinated

[12] As discussed below, the study is limited to the period through 2004 because data used for the empirical analysis were not yet available for 2005.

[13] 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.

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.[14]

Figure 5
Analyzing Actual and Projected Rates



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.[15] First, the model includes a

---

[14] Dr. Kwoka faults this approach arguing that the "two groups differ in a number of unexamined ways, some quite possibly important," and states that coordinated markets and traditional markets "divide sharply along regional lines – with the traditional markets covering the southeastern states and the coordinated market encompasses New England and the mid-Atlantic – a split that raises questions about everything from economic base to weather as intervening variables." John Kwoka, "Restructuring the U.S. Electric Power Sector: A Review of the LECG Study, April 2007 (hereafter "Kwoka 2007"), p. 15. To the contrary, our methodology is appropriate precisely because it does account for historical and geographic differences between the traditional and coordinated market region. As explained above, the study does not simply compare post-coordinated market prices in coordinated and traditional markets; instead it examines how the pre-coordinated market relationship between prices in these regions changed when coordinated markets were implemented. Dr. Kwoka does not identify any difference between the coordinated and traditional market regions that changed, not just existed, around the time coordinated markets were implemented; rather he points to precisely the type of regional differences that are addressed by the study methodology.

[15] Dr. Kwoka's comments suggest that it is necessary or appropriate to control for all possible factors affecting retail rates in order to reach valid conclusions, stating that; "While it goes on to state that some of these issues are "intentionally not controlled for … because of the possibility that they are causally related to the implementation of coordinated markets. No tests of the latter proposition are reported, no sensitivity analyses are conducted, and no discussion of the likely seriousness of these omissions is offered. Given that this concern remains only a possibility and given that most other studies choose to include at least some of these variables, some justification for this study's decision is in order." (Kwoka 2007, p. 13) This view is mistaken. In any statistical analysis there are causal factors that cannot be accurately measured and whose effects are captured in

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.[16] 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,[17] residential sales per customer in each year,[18] and

---

the error term. This does not undermine the validity of those studies; indeed, econometric methodology is premised on the fact that there are such factors reflected in the error term.

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

[17] Dr. Kwoka suggests that "especially troublesome questions surround the inclusion of the variable 'total retail sales,'" (Kwoka 2007, p. 16). This variable is included to control for the impact on costs of scale economies, particularly in distribution. It is conventional to include such a control variable in analyzing distribution system costs; indeed Dr. Kwoka included such a variable in his prior analysis of investor owned and public utility costs. See John E. Kwoka, Jr., "Power Structure: Ownership, Integration and Competition in the U.S. Electricity Industry," 1996 (hereafter "Kwoka 1996"), pp. 62-64, 76-77, the variable "DIST." Dr. Kwoka also included a variable for the square of total sales in his prior work, and we estimated an additional sensitivity case including such a variable (see Tables D-5 to D-8). Inclusion of the square of total sales as a control variable increased the estimated benefits of coordinated markets in almost every model variation and also raised the t statistics, strengthening the initial findings.

Dr. Kwoka expresses a concern regarding the potential for simultaneous equations bias from including the total sales variable, stating that "it is also and indisputably the case that price itself affects demand and hence sales. This dual causation means that simply including sales on the right-hand side of such an equation creates simultaneously bias in the estimates. That is, with causation in both directions, estimating the regression model as if causation were only one way distorts the estimated effects of sales and other variables on price."

Dr. Kwoka is correct regarding the potential for simultaneous equations bias, particularly on the coefficient estimate for total sales. However, we are not interested in the coefficient of the total retails sales variable; it is included only as a control variable.

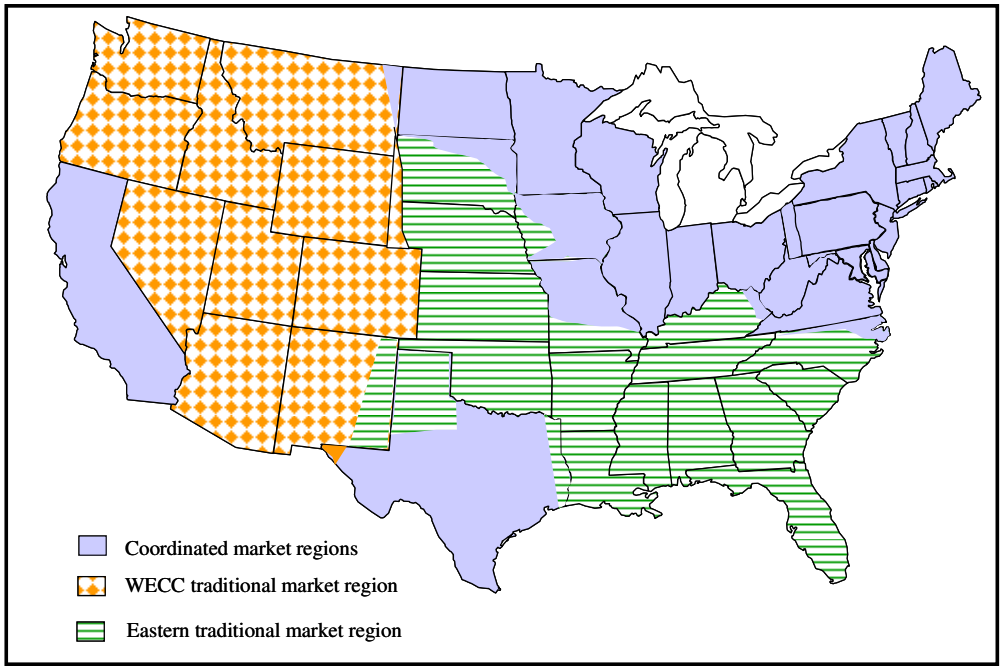
There is a potential for bias in the estimate of the impact of coordinated markets on retail prices; however, this bias depends both on the degree to which retail power sales are sensitive to changes in the price of power and on the correlation between the retail sales variable and the exogenous variables, particularly the coordinated markets variable. The correlation between the retail sales variable and the coordinated market variable ranges from .08 to .11 across the samples used in this paper. Between the limited response of retail sales to variations in the residential price of power and the relatively low correlation between the coordinated market variable and the retail sales variable, it appears somewhat unlikely that any actual bias would raise or lower the estimates of the coordinated market impact by more than a few percent. Nevertheless, we also estimated several models that omit the total sales variable (reported in Tables 19, 20 and 21 and Appendix Tables D-5 to D-10). These models have estimated benefits from implementation of coordinated markets that range from $.44 to $1.78 per MWh.

[18] Dr. Kwoka expresses concern that "no real explanation" is given for the inclusion of this variable (Kwoka 2007, p. 16). This variable is included to control for the impact on residential rates of changes over time in electricity usage per customer. Since some of the distribution system costs associated with serving retail load do not vary with consumption, higher energy usage per customer allows these costs to be recovered in a smaller per kWh change, reducing the retail rate. Such a variable is typically included in distribution system cost studies. Indeed, Dr. Kwoka included such a variable (ResSize) in his earlier analysis of utility costs, see Kwoka 1996, pp. 62-64, 76-77.

proportion of sales going to industrial customers in each year,[19] since each of these variables is expected to have a systematic impact on the average residential rates of individual utilities.[20]

Given the use of a cross-sectional, time-series framework, the next step was the identification of the coordinated and traditional market regions 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



---

[19] Dr. Kwoka also expresses concern regarding the inclusion of a variable for percent industrial sales, questioning its rationale (Kwoka 2007, pp. 16-17). This variable is included to control for possible effects of industrial load on rates, either through rate subsidies or cost impacts. Dr. Kwoka, as well as Dr. Morey and Dr. Kirsch (Mathew Morey and Laurence Kirsch, "Review of LECG Analysis of Coordinated Markets," December 19, 2006, p. 4) point out that the sign of the coefficient estimated for this variable differs across the models, which might indicate that the variable is not well-specified. We therefore reestimated the models omitting the percent industrial load variable (see Tables D-5 to D-8 in Appendix D). Omitting the variable has essentially no impact on the estimated coefficient of the coordinated market variables.

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

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

The utilities located in the coordinated market regions that are analyzed in this study 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.[21]

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.[22] 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 in 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.[23]

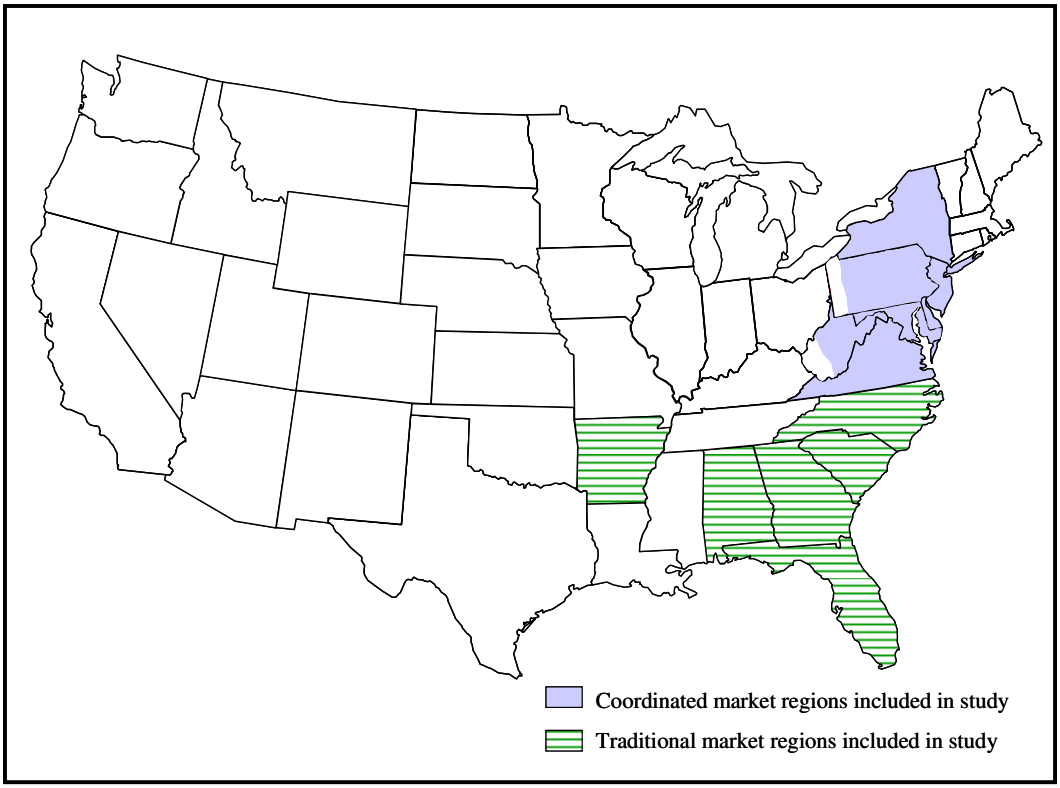
---

[21] 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.

[22] Dr. Kwoka (Kwoka 2007, pp. 14, 22) observes that "evaluating LMP is an interesting and useful exercise, but LMP alone does not capture the full extent of reforms whose effects deserve evaluation, certainly not in a study claiming to analyze coordinated markets." This paper assesses the benefits of implementing LMP-based coordinated markets, which Dr. Kwoka agrees is an interesting and useful exercise. Some might find it interesting to address the question of whether the implementation of coordinated markets in California and ERCOT, even given the flaws in those markets, benefited consumers in these regions. We did not attempt to address that question but others might wish to. As discussed below, such a study would need to control not simply for the importance of hydro generation but for the impact of the western hydro cycle and would of necessity be completely distinct from the analysis we have undertaken. We have also not attempted to assess the benefits of each market design improvement that has been implemented in PJM and New York.

[23] 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 not only to project what rates would have been under the original traditional market structure in New England but to also estimate how the 1999-2003 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. Dr, Kwoka suggests that "outright exclusion of New England because it started LMP in 2003, while including Allegheny which started a year earlier, seems arbitrary." (Kwoka 2007, p. 3, 14) His comments, however, overlook the need to distinguish the effects of implementing LMP-based coordinated markets from the effects of the market design in place from 1999 to 2003.

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.[24] TVA utility customers

[24] 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. Dr. Kwoka confuses our reference to the "western hydro cycle" with reliance on hydro generation (Kwoka 2007, pp. 7, 14), suggesting that all one needs to do to control for the western hydro cycle is to include "a variable for the percent of generation originating with hydro power." This view misunderstands the western hydro cycle, which has impacts that cannot be accounted for simply by controlling for the proportion of hydro generation.

New York state generates considerable electric power using hydro generation (in particular, the Niagara and St. Lawrence projects – see NYISO "2006 Load and Capacity Data," Table III-2, Moses Niagara and St. Lawrence FDR) but the generation output of these projects is fairly stable from year to year and the changes are small relative to total load in the Northeast. The western hydro cycle, however, can result in large year-to-year swings in total hydro generation that are substantial relative to WECC load with associated large swings in the cost of meeting load. This was shown in dramatic fashion in 2000 and 2001 when low hydro generation combined with tight supply, environmental restrictions and gas pipeline constraints, combined to raise spot power prices far above prior year levels. Hence, our conclusion that any comparison between the rates of entities operating in traditional markets in the WECC and the rates of entities operating in coordinated markets needs to be based on entities that are all in the WECC and subject to the same hydro cycle rate impact.

are also excluded from the analysis since they operate in a regulatory 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 also 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 traditional market region to project the average rates in PJM and New York, absent implementation of coordinated markets.[25]

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.[26] 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.[27] In view of the correlation between retail access implementation and

---

[25] Utilities operating in the MISO region and in the 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 of utilities in the coordinated market region in the current period under the traditional market design, since the MISO region was in the process of shifting to coordinated markets during this period.

[26] 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).

[27] 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 were 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 to benefit consumers more than is actually the case in the longer-run when current spot prices are lower than 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.

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 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.[28]

---

[28] Howard Spinner pointed out that the Maryland cooperatives were potentially impacted by the retail access provisions of Maryland's restructuring law (see "A Response to the November 20, 2006 Draft PJM Supported Study by LECG," p. 12). A sensitivity case that excludes the Maryland cooperatives is included in the

The state and regional distribution of the municipal and cooperative utilities included in the study is shown in Table 8.[29]

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	15	46	-	61	11,115,982
Allegheny Power	5	8	-	13	1,849,535
Alabama	15	19	-	34	10,267,984
Arkansas	17	16	-	33	16,919,383
Florida	16	31	-	47	49,848,685
Georgia	40	51	-	91	43,744,979
North Carolina	27	70	1	98	29,172,468
South Carolina	19	21	1	41	28,432,389
Total	**158**	**309**	**-**	**469**	**196,214,596**

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 the average retail rates of utilities. 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 has not been an option within some regions and this constraint existed for the utilities in these regions long before the implementation of coordinated markets.[30] 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. The study therefore needs to take account of regional differences in fuel mix in some manner in order to distinguish the impact of coordinated markets from differences in the impact of changes in gas prices across gas dependent and non-gas dependent regions.

While the contemporaneous fuel mix could have been included as an explanatory variable for retail rates in the econometric analysis, a concern has been expressed that fuel mix choices

---

discussion of the results in Section III (Table 19) and Appendix D (Tables D-1 and D-2). The exclusion reduces the estimated benefits of coordinated markets by less than $.10/MWh in the utility dummy model and raises them by more than $.50/MWh in the 1990 rate model.

29 As discussed in Appendix A, the Long Island Power Authority was not included in the study as a public utility because there was a change in the structure of the Long Island utility, from an investor owned utility to a public utility, around the time that coordinated markets were implemented in New York. The exclusion of LIPA from the analysis is intended to avoid confusing the rate impact of the change in utility structure with the impact of coordinated market implementation.

30 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.

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, or even lead to "overinvestment in gas generation."[31] 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 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,

[31] See Synapse Energy Economics, footnote 34.

North Carolina, South Carolina, Georgia, Alabama and Arkansas), as shown in Table 9.[32] Florida is the state in the Southeast that has retained a 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.

Table 9
Regional Fuel Mix Differences, 1990[33]

	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

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

[32] There is a third potential sample consisting of oil and gas dependent power markets in gas producing regions with wellhead or intrastate gas pipeline supply sources. This would include utilities in the states of 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.

[33] 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 low-cost, coal-fired power, the inability to construct coal-fired generation close to load, in combination with transmission constraints, raises the cost of meeting load located in these regions, and the impact varies with gas and oil prices.

gas generation in their total generation mix and the impact in regions with a much lower use of oil and gas generation.[34]

---

[34] Dr. Kwoka takes the view that this bifurcation is unnecessary, stating that our study "divides its data sample into gas dependent and non-gas dependent states based on the stated belief that the same model might not apply to both. After the fact, it examines the data and concludes that there is no basis for the distinction." (Kwoka 2007, p. 17) We assume that in stating that we conclude that "there is no basis for the distinction," Dr. Kwoka is referring to our observation that "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" (p. 29 in November 2006; p. 39 below). Dr. Kwoka appears to have confused two distinct questions. One question is whether it would be appropriate for the purpose of this study to classify states as gas-dependent or not based on their gas reliance today or whether gas dependence might be endogenous and related to the implementation of coordinated markets. As Dr. Kwoka notes, we are not persuaded that the evidence shows that implementation of coordinated markets increases gas dependence, but we have structured the analysis to account for the possibility that such a relationship exists. A second question is whether the change over time in consumer rates is related to the gas dependence of the regional fuel mix. We expect the change over time in retail power rates to be related to gas dependence, regardless of whether gas dependence is related to the implementation of coordinated markets, so we believe it is appropriate to allow the pattern of rate changes over time to differ between the gas dependent and non-gas dependent regions.

As discussed below, we estimated additional sensitivity cases using a combined sample for the gas dependent and non-gas dependent regions as suggested by Dr. Kwoka, allowing the base rate of change in retail rates to differ between the regions. The results, discussed in Section III below, generally indicate larger cost savings from the implementation of LMP-based coordinated markets than found in the base models.

Dr. Kwoka also finds fault with our approach to classifying regions based on 1990 gas dependence stating that this approach "requires that the 1990 degree of dependence correctly predicts its degree of dependence up to 15 years later for all reasons other than the advent of coordinated markets" (Kwoka 2007, p. 17). Dr. Kwoka's statement is incorrect. The validity of this model only requires that any changes in gas dependence since 1990 that are unrelated to the introduction of coordinated markets not be correlated with the introduction of coordinated markets; that is, our approach yields unbiased estimates of the rate impact of introducing coordinated markets unless rates in PJM and New York have fallen since the introduction of coordinated markets because of reductions in gas dependence that were unrelated to, but correlated with, the introduction of coordinated markets. Dr. Kwoka does not suggest any reason for believing that this has been the case. In 2006, Synapse Energy Economics asserted just the reverse in another APPA funded report, stating that "the overinvestment in gas generation in New England means that gas is the marginal fuel (at least in the eastern part of the region) much of the time, leading to a high correlation between natural gas and electricity prices." Synapse Energy Economics, "LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers," February 5, 2006.

Dr. Kwoka goes on to say that "if more suitable technologies, new gas pipelines, environmental considerations, or simply demand characteristics changed, some or all of the 1990 degree of gas dependence might well have changed absent coordination, and the split sample used in the LECG study would be inappropriate." (Kwoka 2007, p. 17) We understand the point of this comment to be that if any of these factors caused gas dependence to decline in parallel with the implementation of coordinated markets but for some reason these factors only operated in the coordinated market region, then the model could overstate the benefits of coordinated markets. This is correct, but it does not require a change in study methodology because Dr. Kwoka does not identify any such factors that were operative in the coordinated market regions, does not explain why these factors were correlated with but independent of the implementation of coordinated markets, and does not explain why these factors did not also operate in regions not implementing coordinated markets.

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:

- The implementation of coordinated markets has largely coincided with a rise in natural gas prices, making it difficult to distinguish the impact on average rates of implementing coordinated markets.

- In most regions, implementation of coordinated markets has coincided with implementation of retail competition, making it difficult to distinguish the impact of the two changes on average rates.

- 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, absent the implementation of coordinated markets, 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.[35] The source of the annual revenue and megawatt sales data is the EIA Form 861: 1990-2004.[36] The analysis of average 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).

---

[35] 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 timing differences should be greatly reduced for annual data.

[36] The 2005 data were not available until late 2006.

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 years 1999-2004. The variable is set equal to 2/3 for 1998 because PJM's LMP-based coordinated market was implemented on April 1, 1998.[37]

- 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. The variable is set equal to 0.125 for 1999 because New York's LMP-based coordinated market was implemented on November 19, 1999.[38]

- 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. The variable is set equal to 2/3 for the year 2002 because Allegheny joined PJM on April 1, 2002.

- For utilities that are not in classic PJM, Allegheny or New York, 0 in all years.[39]

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.

---

[37] We have defined the coordinated market variable for utilities in the Allegheny control area to take the value 2/3 in 2002 and 1 thereafter, reflecting the point in time at which the Allegheny control area joined the PJM coordinated market. This treatment implicitly controls for the difference in time that the Allegheny utilities have belonged to PJM and participated in its LMP-based coordinated markets, compared to the public utilities located in the original PJM control area. The Allegheny Impact dummy variable for the Allegheny control area was added as an additional check on whether the shorter participation in PJM markets reduced the benefits or whether the benefits were greater than for PJM classic utilities because Allegheny had not been part of a tight pool prior to joining PJM.

[38] Drs. Morey and Kirsch view the results for 1999 as implausible because the "Report predicts that residential customer prices without restructuring in 1999 would have been as different from the actual prices in 1999 as are the predicted and actual prices for the years 2000-2004. It is astonishing that the impact of restructuring in a year with only two restructured months would be of roughly the same size as the impacts in years with twelve restructured months." (p. 4) Their view is mistaken since the coordinated market variable takes the value .125 for the NYISO in 1999, thus the predicted impact of coordinated market implementation in 1999 would be 1/8 the impact in subsequent years.

[39] To address Dr. Kwoka's misunderstanding of the fractional dummy variables and of their relationship to the date LMP-based coordinated markets were implemented in the various regions (Kwoka 2007, p. 9), the relationship between the fractional dummies and RTO market start dates has been clarified in the text.

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.[40]

Individual Utility Effect: Two models are used to account for individual utility rate effects. One is the utility model, which includes Individual Utility Dummies (i) equal to 1 for utility i in all years t, and 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.[41] The second is the 1990 rate model in which each utility's 1990 residential rate is used as a control variable.

The regression equation that is estimated is of the form:

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

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.[42] 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.[43]

---

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

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

[42] The suggestion by APPA (APPA Statement) that this study does not control for year to year changes in fuel costs or fuel mix is incorrect. The study does not explicitly control for differences in the change in reported fuel costs or fuel mix across regions because some analysts have suggested that these differences may themselves be attributable to the structure of the markets. In order to capture the impact of regional differences in fuel mix that reflect historical investments and resource endowments, the study uses state-level fuel mix data from 1990 to segregate the sample. The historical data are used for this purpose because data from 1990 could not depend on whether or not coordinated markets were subsequently implemented. The annual dummy variables are used to control for year to year changes in fuel costs as explained in the text above.

Along similar lines, Dr. Kwoka suggests that "it is better practice to adjust prices directly and allow variables for calendar years to capture influences other than general inflation." (Kwoka 2007, p. 16) Dr. Morey and Dr. Kirsch make similar comments (p. 3). It is noteworthy that Dr. Kwoka and Drs. Morey and Kirsch do not suggest any appropriate control variable. The CPI or GNP deflator would not provide a sensible measure of fuel cost impacts on power prices. A gas price or coal price index would only be relevant to the extent these fuels were needed to meet load and their impact on consumer rates would likely vary seasonally. While our estimates are not as precise as those one could obtain with a perfect deflator for costs, the estimates are still unbiased. Moreover, we do not have a suitable deflator for costs, and the methodology we have used in the study is superior to using misspecified cost indexes.

[43] Drs. Morey and Kirsch assert that this methodology overlooks the possibility that the public utilities in the southeast may jointly procure power and as a result of this joint procurement, "an assumption that the rates of the utilities within the southeastern 'control group' sample are independent is violated and thus the model

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 the control variable for regional economic conditions might in fact be a result of the coordinated market effects that we seek to measure.[44] This approach has the advantage that, to the extent that coordinated market implementation is hypothesized to indirectly affect average consumer rates through impacts on gas prices, the model would identify the ultimate impact on average consumer rates of implementing coordinated markets regardless of whether that impact were direct or indirect through an effect on gas prices. Thesdummy variables provide an imperfect measure of the exogenous changes in costs that affected consumer electricity rates across the regions but this imprecision is unavoidable if the study is to address the concern that implementation of coordinated markets might itself result in changes in regional fuel costs. Conversely, 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.[45]

Similarly, the study does not attempt to control for differences in forward contracting across the public utilities in the sample, because differences in the cost of entering into forward hedging contracts might reflect the impact of implementing coordinated markets. If there are differences in the degree of forward contracting that are unrelated to but correlated with the

---

estimates are biased." (p. 3-4) The unbiased property of the coefficient estimate for coordinated markets depends on whether the coordinated market variable is correlated with omitted variables that are reflected in the error term. If the public utilities in the southeast belonged to a cost saving organization that was dissolved around the time that coordinated markets were implemented in New York or PJM, this might bias the estimated coefficient, but Drs. Morey and Kirsch do not suggest this has happened. Participation in joint procurement practices that reduced rates in the southeast throughout the period studied would not lead to any correlation between increased rates in the Southeast and implementation of LMP-based coordinated markets in New York and PJM and therefore does not bias the estimates of the impact of implementing coordinated markets.

44 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.

45 We also have not included the wholesale price of power as a control variable. While it would be possible to estimate a two-stage models treating the wholesale price variable as an endogenous control variable that is, in turn, impacted by exogenous cost shifters and the implementation of coordinated markets, that approach would have several limitations. First, while transparent wholesale spot power prices would be available for the coordinated market regions subsequent to the implementation of coordinated markets, such data are not available prior to the implementation of coordinated markets or in the regions in which no coordinated markets have been implemented. Second, some of the other cost shifters that would determine the wholesale market price would themselves be potentially endogenous. Third, since the impact of coordinated market implementation on utility costs and retail rates occurs not only through the wholesale price of power but also through ancillary service costs, embedded cost charges for transmission access, installed reserve or capacity market costs, RTO charges etc., there is no apparent advantage to attempting to estimate a two-stage model, since the rate impact of these other costs also would need to be taken into account.

implementation of coordinated markets, these differences could be reflected in the estimated effect of coordinated markets.[46]

The model also does not separately control for (i.e., attempt to hold constant) the competitiveness of regional wholesale power markets or the effect of mergers but instead allows differences in competitiveness between coordinated and traditional markets to be reflected in the estimated impact of coordinated markets. Thus, if power prices in wholesale markets in coordinated market regions have risen more than in traditional markets because of a lack of competition in coordinated markets or an increase in concentration in these markets, this would be reflected in the average rates of the public utilities that participate in the coordinated markets and identified by this study as higher rates of utilities located in coordinated markets.[47]

---

[46] Mr. Spinner has pointed out that the regression analysis does not control for differences in the regulation of public utilities across the regions analyzed in the study and suggests that the coordinated market variable may therefore reflect the rate impact of differences in regulatory structure, rather than the impact of introducing coordinated markets (see "A Response to the November 20, 2006 Draft PJM Supported Study by LECG," p. 11.) This should not be the case, however. The analysis does not simply compare rates in New York and the PJM states to rates elsewhere, precisely because simple rate differences could arise from many sources unrelated to the implementation of coordinated markets, such as differences in regulatory policy. The study compares rates across regions and the changes in the relationship between these rates over time. Only improvements in New York and PJM regulation that were more or less coincident with the implementation of coordinated markets in those regions would be correlated with the coordinated market variable. Moreover, if improvements in New York and PJM regulation were observed to be coincident with implementation of coordinated markets in those regions, those improvements might in fact be a consequence of the greater market transparency resulting from implementation of coordinated markets, and it would therefore be inappropriate to exclude such rate impacts unless it is known that this improved regulation was exogenous.

Drs. Morey and Kirsch suggest that it is possible that "restructuring in the high-priced markets may have increased the flow of power from the low-cost states to the high-cost states, thus raising wholesale market prices in the Southeast, raising wholesale supply costs for southern munis and coops, and thus contaminating the "control" data of the Southeastern utilities." (p. 2) It is certainly possible that the implementation of LMP-based coordinated markets in New York and PJM made it less costly for external suppliers to sell power into these markets, thereby contributing to a reduction in consumer rates in the coordinated market region, but it is not known whether such a material reduction in import supply costs actually occurred.

Given the number of intervening control areas and pancaked transmission charges, it is fairly implausible, however, that the PJM or New York markets drew material supply from Arkansas, Florida, Alabama, South Carolina or Georgia, much less that the imports were of a sufficient magnitude to materially impact wholesale power prices in the non-coordinated market regions. Moreover, even if such an impact on wholesale market prices had occurred, the premise that an increase in wholesale market prices in the non-coordinated market regions would raise retail rates does not necessarily follow. To the extent that munis and coops in the Southeast had excess capacity, they and their rate payers might benefit from increased sales at market-based prices to load-serving entities in PJM. Moreover, power flows out of PJM as well as into PJM so consumers in control areas adjacent to PJM's coordinated markets would likely benefit from lower costs of acquiring supply from PJM during high load conditions. Indeed, if the public utilities in the traditional market were located in control areas adjacent to classic PJM they would likely receive many of the benefits from LMP-based coordinated markets without having to pay for those markets. As we noted above, however, the public utilities in the sample are not located in control areas adjacent to classic PJM, and in most cases they are located in control areas far from PJM, so the interactions are unlikely to be material.

[47] Drs. Morey and Kirsch assert that it is likely that "prices in high-cost states (of New York and PJM) would have fallen toward those in the low-cost states (of the Southeast) because of the expiration of high-cost legacy

Dr. Kwoka has suggested that "restructuring has been accompanied by market power, market manipulation, and mergers involving many utilities. Wholesale power markets have become increasingly concentrated, raising concerns over market power."[48] If this characterization were accurate, and the effects material, then this study should find an association between the implementation of coordinated markets or restructuring and higher consumer rates, the opposite of the relationship actually found.

The model also does not control for changes in state taxes collected from electric utilities.[49] 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.

III. RESULTS

A. Base Models

This study compares average public utility residential rates in New York, New Jersey, Delaware, and PJM-Maryland (eastern) 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 eastern PJM and New York that existed over the period 1990-1997.[50] In this analysis, the

---

obligations in the high-cost states," (p. 2) but provide no basis for their view that high power costs in the Northeast were a short lived anomaly.

[48] Kwoka 2007, pp. 4, 23. Dr. Kwoka provides no explanation of, nor citation for, the basis for his assertion that wholesale power markets have become "increasingly concentrated." This assertion appears to be inconsistent with actual concentration trends in LMP-based coordinated markets in which concentration has been reduced both by divestitures and the entry of many new suppliers, unless Dr. Kwoka has in mind an unusual market definition. Calculations in the PJM State of the Market Report indicate that overall concentration has decreased substantially following implementation of LMP-based coordinated markers (see PJM Interconnection, State of the Market Report 2000, Table 2, p. 24 and 2004, Tables 2-4 and 2-5, p. 54). While there are many alternative market definitions and reasonable people can disagree about which is most appropriate for various purposes, it is hard to conceive of any sensible market definition under which concentration in PJM markets has increased since 1998.

[49] 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.

[50] Dr. Kwoka criticizes the use of Florida as a control on several grounds. (Kwoka 2007, p. 15) First, he mentions high per household electricity consumption in Florida. This is accounted for both in the use of a pooled time series and cross sectional model, which compares Florida rates and rates in the other states over time, and in control variable for average changes in residential consumption over time. Second, he mentions storms and

estimated rate impact of coordinated markets is to reduce average retail rates in the coordinated market regions (New York and eastern PJM) by around $1.5 per megawatt hour, as shown in Tables 10 and 11.[51] The differences in average rates are statistically significantly different from zero at traditional confidence levels.[52]

---

power outages but does not identify any correlation between changes in Florida weather and implementation of coordinated markets in PJM and New York. Third, he mentions sharply constrained electric capacity since 2000, but does not explain why that should be viewed as independent of the traditional market design and the lack of a transparent spot market based on LMP in Florida. While the implementation of LMP-based markets has not eliminated the intrinsic difficulties of siting generation in the northeast, some of the rate changes in PJM and New York may reflect the beneficial effect on the ease of entry of the creation of a transparent spot market and use of locational pricing. Fourth, Dr. Kwoka cites a rapidly growing dependence on gas in Florida. In contrast, other APPA consultants (Synapse Energy Economics; see footnote 34) identify coordinated markets with a growing gas dependence.

[51] Mr. Spinner has suggested (pp. 12-13) that the estimated effect of coordinated market implementation on consumer rates may reflect the rate impact of relatively low priced NYPA preference power. (See also Kwoka 2007, p. 21) This would not be the case, however, because the study does not simply compare the rates in New York and PJM following the implementation of coordinated markets to rates in other regions during this period, but utilizes a combined time series and cross sectional model. Thus, any rate impact from NYPA hydro power would be present before and after the implementation of the LMP market in New York. The rate impact of NYPA preference power would be correlated with the coordinated market variable and bias the estimate of coordinated market impacts only if there were a material change in the level of preference power that was roughly coincident with the implementation of coordinated markets in New York in late 1999. Mr. Spinner does not suggest that any such change in the allocation or amount of NYPA preference power occurred in the late 1990s.

The effect on consumer rates of increases in the market price of power may be larger for LSEs with a large base of very low cost power than for LSEs whose power supply is priced closer to the market, the opposite of the relationship assumed by Mr. Spinner. For example, an LSE that purchases 100% of its power at $50/MWh in period 1 but then must purchase 10% of its power at $100 in period 2 sees a $5/MWh increase in its average cost of power from $50 to $55. For an LSE that purchases 100% of its power at $80 in period 1 and then must purchase 10% of its power at $100/MWh in period 2, the increase in its average cost of power is only $2/MWh, from $80 to $82/MWh. Thus, low rates supported by low-cost power may lead to larger rate increases when the cost of new supply rises rapidly. This relationship implies that if Mr. Spinner is correct that below-market NYPP preference power reduces the rates of New York municipal utilities, the estimated benefits from coordinated market implementation could be understated, not overstated, during a period of rising power prices because of the impact of hydro power costs on the rates of New York public utilities.

Dr. Kwoka also criticizes the study because it "does not examine the extent to which lower prices in New York during the period of coordinated markets might be simply the result of the changing mix of preference power vs sales reflecting market prices" (Kwoka 2007, p. 21) but fails to provide a reason that there would be a correlation with implementation of coordinated markets. Moreover, his prior analysis of the costs of public and private utilities reached conclusions regarding differences between public and private utility costs without including any control variables either for the price at which public utilities purchase such preference power or the amount on preference power (see Kwoka 1996, pp. 73-77 and 83). A more recent paper authored by Dr. Kwoka, "The Comparative Advantage of Public Ownership: Evidence from U.S. Electric Utilities," *Canadian Journal of Economics*, May 2005, p. 622, reaches similar conclusions while controlling only for the amount of purchased power, not its price, and this model found a cost raising effect of purchased power (p. 632).

Dr. Morey and Kirsch make a somewhat different but related claim, that because "New York's munis and coops have for many years obtained up to 100% of their power requirements from the New York Power Authority under low-cost long-term contracts … the rates of these munis and coops could not have been affected by the development of the coordinated markets during the study period, and that their rates largely reflect pre-existing contractual commitments rather than the introduction of coordinated markets." (p. 3) These

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	-$0.879/MWh (1.41)	
Low Gas Dependence Regions And APS (n = 5190) r^2 = .854		
Pennsylvania, APS Maryland, West Virginia, Carolina, South Carolina, Georgia, Alabama, Arkansas	-$.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 (western PJM), to public utility rates in North Carolina, South Carolina, Georgia, Alabama and Arkansas, regions which all had low levels of

---

assertions are not consistent y with the actual structure of both traditional and coordinated markets. The munis and coops in New York paid pancaked transmission charges under the traditional market design which they have had the opportunity to eliminate under the LMP-based market design in place since 1999. They have also had the opportunity to convert firm transmission rights into financial transmission rights (TCCs), and they and the New York Power Authority have had the opportunity to convert physical supply contracts and scheduling practices into financial contracts.

Moreover, LSEs that attempt to hedge their consumption through forward contracts do benefit from the implementation of LMP-based coordinated markets through the lower cost at which forward contracts are likely to be available as discussed in footnote 60 below.

If the base model is re-estimated excluding the New York public utilities, the estimated effect of coordinated markets rises from -1.621 to -4.781 in the utility dummy model and falls from -1.415 to -.707 in the 1990 rate model. Moreover, whatever the overall impact of recent fuel price increases on the rates of New York municipals, those utilities are not included in the non-gas dependent sample, which also shows consumer rate benefits from the implementation of coordinated markets.

[52] In running a sensitivity case that excluded the Maryland cooperatives from the sample, it was noticed that the "missing data" that caused observations for A&N Electric to be excluded from the original gas-dependent sample were almost certainly not actually "missing" data but were data taking the value zero and recorded as a blank in the EIA data. Re-estimating the model including observations for A&N Electric Cooperative lowers the coordinated market coefficient slightly to -1.613 in the utility dummy model, and to -1.24 in the 1990 rate models (see Tables D-1 and D-2 in Appendix D).

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.[53]

The signs of the coefficients 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.[54] 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 (Table 10), an alternative model was estimated that used each utility's 1990 average residential rate as a control variable (Table 11). The effect of including the 1990 utility rate as a control variable is similar to using utility dummy variables but it imposes greater restrictions in fitting the model 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 as control variables. 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

---

[53] It was pointed out that the Blue Ridge Electric Member is a TVA entity and should not be included in the sample for any of the states in which it operates. Excluding observations for Blue Ridge changes the coordinated market coefficient from -.879 to -.877 for the utility dummy model and from -1.871 to -1.870 for the 1990 rate model (see Tables D-3 and D-4 in Appendix D).

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

are generally similar to the effects 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).[55]

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	-$1.872/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)

Howard Spinner has pointed out that Maryland cooperatives were potentially impacted by the Maryland restructuring law, which might downward bias the estimated effect of coordinated markets on public utilities. To test for this possibility, the gas-dependent region model was re-estimated excluding the Maryland cooperatives (all Maryland cooperatives were in the gas-dependent sample; none are located in western Maryland). This exclusion reduced the magnitude of the estimated coefficient of the coordinated market variable from -1.621 to -1.546 in the utility dummy model and raised the magnitude of the estimated coefficient from -1.415 to -1.944 in the 1990 rate model (see Tables D-1 and D-2 in Appendix D).

---

[55] 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 sample 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 observations by the square of the variance estimated from residuals of the regression 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 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 as shown in Tables 10 and 11.[56] 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.[57]

B. Sensitivity Cases

We also estimated a number of sensitivity cases. For the gas dependent region sample, these sensitivity cases dropped the Maryland coops from the sample, added the A&N coops to the sample, dropped the New York munis from the sample, dropped the industrial load control variable, added retail sales squared as a control variable, and dropped Total Sales as a control variable, to address various comments on the original results. The estimated coefficients for the coordinated market variable for these sensitivity cases are shown in Table 19. In most cases the change in the estimated rate savings are not very large, although dropping the NY municipals from the sample greatly raises the estimated savings in the utility dummy model and halves the estimated rate savings in the 1990 rate model.

Table 19
Sensitivity Cases for Gas-Dependent Sample
Coordinated Market Impact

Coefficient Estimate Summary							
				Include A&N			
	Base Model	Exclude Maryland Coops	Include A&N	Drop New York Munis	Drop Industrial Load Variable	Add Retail Sales Squared	Drop Retail Sales
Utility Dummy Model	-1.621	-1.546	-1.613	-4.781	-1.780	-1.924	-.78
t-statistic	2.61	2.44	2.63	5.08	2.90	3.09	1.31
1990 Rate Model	-1.415	-1.943	-1.24	-.707	-1.23	-1.147	-1.17
t-statistic	2.01	2.71	1.79	.71	1.79	1.65	1.72

[56] Excluding observations for Blue Ridge from the APS model (see footnote 53) changes the estimated coefficient of the coordinated market variable from -.800 to -.803 in the utility dummy model and from -1.474 to -1.470 for the 1990 rate model (see Tables D-3 and D-4 in Appendix D).

[57] Dr. Morey and Kirsch take the view that the inclusion of the Allegheny impact variable, allowing for a differential impact of coordinated markets on the utilities joining PJM during 2002, reflects some unexplained problem relating to "anomalous data." (p. 4) While the basis for their view is not explained, it is straightforward to re-estimate the model omitting the Allegheny dummy variable. This sensitivity case is reported in Table 20, and the omission has little effect on the estimated benefits from implementing coordinated markets.

Similarly, we estimated a number of sensitivity cases over the non-gas dependent region sample. All of the sensitivity cases dropped all of the Blue Ridge entities that were TVA participants. Additional sensitivity cases dropped the industrial load control variable, added retail sales squared as a control variable and dropped the APS region dummy in the sample that included the APS control area. The estimated coefficients for the coordinated market variable for these sensitivity cases are shown in Table 20. In most cases the change in the estimated rate savings are not very large, although adding the retail sales squared variable tends to raise the estimated rate savings in all of the models.

Table 20
Sensitivity Cases for Non-Gas-Dependent Sample
Coordinated Market Impact

Coefficient Estimate Summary						
			Exclude Blue Ridge			
	Base Model	**Exclude Blue Ridge**	**Drop Industrial Load**	**Add Retail Sales Squared**	**No APS Dummy**	**Drop Retail Sales**
Original PJM						
Utility Dummy Model	-.879	-.877	-.814	-1.163	NA	-.52
t-statistic	1.41	1.40	1.30	1.86		.83
1990 Rate Model	-1.871	-1.87	-1.89	-1.953	NA	-1.79
t-statistic	2.61	2.60	2.63	2.72		2.48
Include APS Region						
Utility Dummy Model	-.803	-.800	-.735	-.949	-.674	-.44
t-statistic	1.30	1.29	1.18	1.66	1.18	.72
1990 Rate Model	-1.474	-1.470	-1.50	-1.587	-1.50	-1.36
t-statistic	2.08	2.07	2.11	2.24	2.24	1.92

In addition, we estimated a model based on a combined sample for the gas dependent and non-gas dependent regions, allowing the rate of year to year change in rates to differ between regions by including distinct annual dummies for the gas dependent and non-gas dependent regions, allowing the year-to-year change in rates to differ between the gas dependent and non-gas dependent regions. These models tended to find larger benefits from the implementation of coordinated markets than did the models estimated separately for the two regions.[58]

Table 21
Combined Sample
Coordinated Market Impact

	Utility Dummy Model	1990 Rate Model
Base Coefficient ($/MW)	-1.266	-1.874
t-statistic	2.85	3.67
Total Sales Squared	-1.48	-1.95
t-statistic	3.32	3.87
Drop Total Sales	-.734	-1.695
t-statistic	1.68	3.33

C. Discussion

This statistical analysis of average consumer rates focuses on the average residential rates of public utilities, rather than on 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.[59] Similarly, absent reasons to believe that public utilities benefit disproportionately

---

[58] Detailed results are reported in Table D-9.

[59] Dr. Kwoka suggests that the cost savings estimated for residential customers do not extend to industrial customers because "elsewhere this same report claims that only residential customers are sufficiently homogenous to be treated as a group" (Kwoka 2007, p. 19).

Dr. Kwoka confuses two questions. One question is whether one can sufficiently control for differences in industrial customers across distribution companies and over time for a given distribution company, to identify rate changes related to implementation of coordinated markets. Because we were unsure of our ability to adequately control for these differences, we focused our analysis on residential rates. A second question is whether the cost savings from implementation of coordinated markets are passed through in the rates of all customers or only to residential customers. (The converse of this would be an assumption that cost increases are passed through disproportionately in residential rates rather than industrial and commercial rates). We are

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.[60]

The average consumer rates examined in the study 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).[61] Because RTO costs are recovered from market

---

not aware of any reason to expect that the cost savings passed through to industrial and commercial customers would be either greater or lower than the cost savings passed through in the rates of residential customers.

[60] Drs. Kwoka, Morey and Kirsch have taken the view in commenting on an earlier version of this paper that the estimated rate benefits cannot be projected to the customers of investor owned utilities because implementation of coordinated markets has disproportionately benefited public utilities (see Kwoka 2007, pp. 19-20, 27; and Morey and Kirsch p. 2). Neither Dr. Kwoka nor Drs. Morey and Kirsch have provided an explanation of why they think it likely that implementation of coordinated markets in PJM and New York has disproportionately benefited public utilities.

Drs. Morey and Kirsch argue (p. 2) that the estimated savings for munis and cooperative customers would not be applicable to customers who are served by IOUs because "munis and coops typically had higher percentages of their load covered by owned generation or longer-term power purchase contracts than many of the IOUs in the period 1998-2004, giving munis and coops very different cost and market exposure than IOUs. Long-term contracts and power supply arrangements may have significantly reduced market exposure for some munis and coops during the chosen study period."

This comment (and the similar comments in Kwoka 2007, pp. 19-20, 21-22) is both irrelevant and premised on a misunderstanding of competitive power markets and forward hedging. First, any differences in hedging between public utilities and IOUs do not affect the results of this study because the study is restricted to an analysis of the rates of public utilities. Second, if the point of these comments regarding the existence of long-term contracts and power supplies is that because of these long-term arrangements the benefits from implementing LMP-based coordinated markets may not be fully reflected in the rates of public utilities for a number of years, that is possibly the case but it is a reason to believe that this study may understate the benefits from implementing LMP-based coordinated markets.

Third, if the point of these comments is to suggest that public utilities that extensively hedge their cost of meeting load through long-term contracts and other long-term supply arrangements would not benefit from more efficient spot power markets and congestion management, that view is mistaken.

The cost of forward supply contracts depends on the cost to the seller of covering its obligation and if the market design and regulatory structure makes it artificially expensive for a seller to cover its forward contracts, then forward contract prices may materially exceed expected future prices, raising the cost of forward hedging for load-serving entities, including public utilities. One of the benefits from the implementation of LMP-based coordinated markets is a reduction in the cost of covering forward contracts, leading to a reduction in the cost of forward contracting for loads. It is not coincidental that the PJM western hub is one of the most liquid forward power markets in the world. This is a benefit from the implementation of LMP-based coordinated markets.

[61] Dr. Kwoka agrees with this characterization, but states that the study approach "fails to address the fact that RTO costs are expected to increase in all regions as additional institutions and procedures are put into place" (Kwoka 2007, p. 24). If Dr. Kwoka's point is that if RTOs were in the future to put in place new programs that did not provide incremental benefits commensurate with their costs then the consumer benefit from implementation of coordinated markets would be reduced, his comment is valid but is irrelevant to this study. We, of course, agree that RTOs, FERC and RTO market participants and stakeholders need to make sure that new programs are likely to lead to further cost reductions for market participants and benefits to consumers.

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.

One might question whether there is sufficient retail competition to ensure that the estimated benefits from the implementation of coordinated markets, and presumably other cost reductions, will flow through to retail consumers not served by public utilities or utilities subject to rate regulation.[62] The degree to which these cost savings have been passed through in retail prices in retail access states was not examined in this study and it is possible that only a fraction of the cost changes have flowed through into retail rates in some states or service territories. On the other hand, the reason that there has been so much concern with the level of power rates in retail access states is in large part because the increases in wholesale power prices attributable to fuel price increases are being passed through in retail rates, so the premise that consumer rates in retail access states do not respond to cost changes is of questionable validity.

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 in the period studied. One of the objectives of the relevant state regulators, RTOs and market participants is to further improve RTO markets and reduce RTO costs so as to maintain and increase these benefits in the future, so the long-run benefits could prove to be greater.

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. For this analysis, data on oil and gas dependence by state over the period 1990-2004 were gathered and summarized in tabular form, as shown 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 states with a traditional electricity market structure such as Alabama and Florida, as shown in Table 12.[63]

---

[62] See, for example, Howard Spinner, p. 8.

[63] 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.[64]

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

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

In the states in the until-very-recently-traditional Midwest market region, gas dependence has remained low throughout the 1990-2004 period, as shown in Table 14.[65]

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

[65] 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 states 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).[66]

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

[66] 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 from 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

This study shows that the implementation of coordinated markets has reduced 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. This conclusion is based on the analysis of several models and sensitivity analyses. All of the models yielded estimates of reductions in average residential rates arising from implementation of coordinated markets of $.50 per megawatt hour or more; some provided estimated savings approaching $2.00 per megawatt hour, while a number estimated savings in the range of $1.50 per megawatt hour.[67]

This paper contains a range of estimates of the benefits from the implementation of coordinated markets, varying across the gas dependent and non-gas dependent region and across the results of different models for given regions.[68] We are comfortable with these ranges and believe that they are consistent with the question we are attempting to address. We are not attempting to develop a point estimate for a physical constant such as the boiling temperature of water at a given pressure but to estimate the expected net benefits from implementation of LMP-based coordinated markets.

We think it likely that the benefits from implementation of LMP-based coordinated markets will vary over time and across consumers with variations in congestion patterns, past transmission investments, degree of regulatory stress, level and volatility of oil and gas prices, and other factors. We have not attempted to develop a model to predict the benefits to each utility in each year and have instead tested high level formulations that assess the average net benefits by year across utilities. Since the actual economic and weather relationships that will determine the net benefits in any particular year are much more complex than any model we estimate, we have not identified one of the models that we have estimated as the "correct" model. Instead, we think it is significant that we find over a variety of models applied to multiple regions that the estimated net benefits from the implementation of LMP-based coordinated markets are consistently positive, and often statistically significantly different from zero at conventional confidence levels.

The implication of this study for state and federal regulators and other policy makers to whom it is suggested that coordinated markets do not provide benefits to consumers that are commensurate with the costs is that none of the models analyzed in this provide support for such a view and some indicate that such a view can be rejected at a high confidence level.[69]

---

[67] APPA and Howard Spinner have observed that the estimated cost savings from the implementation of coordinated markets would only result in a small percentage reduction in rate payer costs. This is correct. The overall dollar amount of the estimated savings implied by the percentage savings is nevertheless potentially quite large, particularly since the savings are ongoing. Moreover, regardless of whether the savings are large or small in percentage terms, since they are net of RTO costs, it is in the interests of consumers to realize these cost reductions, even if these savings alone are not enough to offset the impact on consumer rates of rising fuel costs. Cost reductions need to be achieved where and when they are possible.

[68] See Dr. Kwoka's comments regarding "result instability," pp. 9-10, 18 and heteroskedasticity, pp. 10, 18, as well as the similar comments of Drs. Morey and Kirsch, pp. 4-5.

[69] APPA has noted that several municipal or cooperative utilities operating in coordinated markets have incurred unhedged congestion costs (APPA Statement). It is important to understand that the existence of unhedged

Moreover, 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 in absolute terms. 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.

---

congestion costs is not the result of the implementation of coordinated markets. On the contrary, unhedged congestion costs exist in both traditional and coordinated markets, reflecting the reality that transmission constraints exist because building transmission is expensive, so the cost of eliminating transmission congestion may be far more than paying for high-cost generation. The congestion costs arising from limited transmission capacity are made apparent, but not caused by the implementation of coordinated markets and LMP. The APPA observation that entities may incur unhedged congestion charges in coordinated markets is fully consistent with the findings of this study that implementation of coordinated markets has reduced consumer rates. Transmission constraints exist in traditional markets as well as in coordinated markets. The cost of these constraints is simply less transparent in traditional markets in which congestion costs are not explicitly reported. Note, for example, the comment of the Public Works Commission of the City of Fayetteville, North Carolina, which serves its load using network transmission service purchased from Progress Energy, that "Since the Progress transmission system is constrained, time is of the essence for requesting transmission improvements which may be needed to deliver any resources from outside the Progress control area" (*Megawatt Daily*, January 18, 2007, p. 8).

A critical difference between traditional and coordinated market regions with regard to transmission costs is the potential for greater utilization of the transmission grid in coordinated markets based on real-time economic dispatch and LMP pricing, resulting in lower unhedged congestion costs for a given level of transmission grid investment. It is well established that traditional contract path scheduling practices chronically underutilize the transmission system by not allowing the scheduling of transactions across flow gates that are unconstrained in real-time (see McNamara and MISO above). This underutilization of constrained elements of the transmission system in traditional markets requires that rate payer load be met with higher cost generation than would be necessary in a coordinated market, raising consumer rates.

Bibliography

American Public Power Association, "Statement of the American Public Power Association," December 1, 2006.

Elcon, Supplemental Comments in FERC Docket AD07-7-000.

Harvey, Scott M., Bruce M. McConihe and Susan L. Pope, "Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges," November 20, 2006.

Kwoka, John, "Restructuring the U.S. Electric Power Sector: A Review of the LECG Study, April 2007.

Kwoka, John, "The Comparative Advantage of Public Ownership: Evidence from U.S. Electric Utilities," *Canadian Journal of Economics*, May 2005.

Kwoka, John E., Jr., "Power Structure: Ownership, Integration and Competition in the U.S. Electricity Industry," 1996, Kluwer Academic Publishing.

McNamara, Dr. Ronald R., 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.

MISO, "The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets, Initial Results," March 26, 2004.

Morey, Matthew and Laurence Kirsch, "Review of LECG Analysis of Coordinated Markets," December 19, 2006.

NYISO "2006 Load and Capacity Data," Table III-2, Moses Niagara and St. Lawrence FDR.

PJM Interconnection, State of the Market Report 2000.

PJM Interconnection, State of the Market Report 2004.

Spinner, Howard, "A Response to the November 20, 2006 Draft PJM Supported Study by LECG."

Synapse Energy Economics, "LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers," February 5, 2006.

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);[70] 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.[71] 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

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

[71] 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, Easton Utilities, A&N Electric.
  - In VA: A&N Electric.

- 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 in MAAC from 1990-1999, and in ECAR 2000-2004. New Wilmington is in the Ohio Edison control area and 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 only 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.
- Five entities located in Georgia, North Carolina and South Carolina are excluded because they are TVA munis and coops: Blue Ridge Mountain E.M.C. (GA, NC, SC),

City of Chickamauga (GA), North Georgia Electric Member Coop (GA),Tri-State Electric Member Corp (GA/NC), and City of Murphy (NC).

- 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 of public utilities because it was a public utility only at the end of the study period.
- 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.[72] 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.

---

[72] 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
Dependent Variable: Residential Rate

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
Dependent Variable: Residential Rate

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
Dependent Variable: Residential Rate

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
Dependent Variable: Residential Rate

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
Dependent Variable: Residential Rate

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
Dependent Variable: Residential Rate

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

Appendix D

Additional Sensitivity Cases

Table D-1
Utility Dummy Model
Dependent Variable: Residential Rate

Coefficient Estimate Summary – East Coast Gas Region				
	Base Model	**Exclude NYISO Publics**	**Exclude Maryland Cooperatives**	**Include A&N**
Coordinated Market	-1.621	-4.781	-1.546	-1.613
t-statistic	2.61	5.08	2.44	2.63
APS Region	NA	NA	NA	
t-statistic				
Total Sales	-.0000044	-.0000037	-.0000042	-.0000044
t-statistic	4.96	3.65	4.59	5.01
Average Residential Load	-1.496	-4.51	-1.495	-1.491
t-statistic	9.75	13.43	9.71	9.80
Proportion Industrial Load	-8.95	-14.70	-9.22	-8.95
t-statistic	4.37	4.81	4.48	4.40
Constant = 1990	105.65	140.22	105.24	105.55
1991	0.76	1.29	0.71	0.85
1992	1.11	0.23	.98	1.21
1993	3.31	5.14	3.15	3.39
1994	3.17	4.85	2.97	3.26
1995	3.92	6.86	3.73	4.00
1996	4.01	6.52	3.82	4.03
1997	4.06	5.57	3.91	4.09
1998	4.47	8.37	4.26	4.49
1999	4.33	7.50	4.10	4.39
2000	7.15	9.68	6.92	7.17
2001	11.14	15.58	11.02	11.22
2002	10.96	17.99	10.84	11.06
2003	14.09	20.56	14.02	14.17
2004	16.71	24.47	16.66	16.78
R^2	0.943	0.728	0.948	0.948
N	1830	1065	1800	1860

Table D-2
1990 Rate Model
Dependent Variable: Residential Rate

Coefficient Estimate Summary – East Coast Gas Region				
	Base Model	**Exclude NYISO Publics**	**Exclude Maryland Cooperatives**	**Include A&N**
Coordinated Market	-1.415	-.707	-1.943	-1.24
t-statistic	2.01	.71	2.71	1.79
APS Region				
t-statistic				
1990 rate	.879	.481	.875	.881
	100.25	18.50	99.56	101.52
Total Sales	-.00000012	-.00000078	-.00000021	-.00000013
t-statistic	.62	3.71	1.09	.68
Average Residential Load	-.592	-1.33	-.637	-.600
t-statistic	7.97	9.27	8.53	8.15
Proportion Industrial Load	.017	3.36	.314	.122
t-statistic	.02	2.25	.30	.12
Constant = 1990	14.30	57.57	14.97	14.25
1991	0.76	1.07	0.73	0.84
1992	1.00	0.21	0.89	1.10
1993	2.86	3.68	2.75	2.93
1994	2.46	2.89	2.32	2.55
1995	3.04	3.63	2.93	3.14
1996	2.76	2.33	2.66	2.80
1997	3.03	2.43	2.95	3.07
1998	2.99	1.89	2.96	3.01
1999	2.77	0.83	2.78	2.80
2000	5.07	2.29	5.34	5.01
2001	8.93	8.22	9.31	8.92
2002	8.32	8.60	8.71	8.34
2003	11.02	10.65	11.51	11.04
2004	13.77	14.91	14.27	13.76
R^2	0.892	0.496	0.894	0.892
N	1830	1065	1800	1860

Table D-3
Utility Dummy Model
Dependent Variable: Residential Rate

Coefficient Estimate Summary – Non-Gas Region				
	Base Model	**Exclude Blue Ridge**	**Include APS**	**Include APS Exclude Blue Ridge**
Coordinated Market	-.879	-.877	-.803	-.800
t-statistic	1.41	1.40	1.30	1.29
APS Region	NA	NA	.708	.72
t-statistic			.50	.51
Total Sales	-.0000034	-.0000034	-.0000034	-.0000034
t-statistic	4.82	4.82	4.90	4.90
Average Residential Load	-2.91	-2.90	-2.87	-2.87
t-statistic	28.8	28.70	28.81	28.72
Proportion Industrial Load	4.35	4.37	4.77	4.78
t-statistic	2.72	2.72	3.06	3.05
Constant = 1990	120.26	120.25	119.71	119.70
1991	2.81	2.81	2.81	2.81
1992	4.22	4.21	4.28	4.27
1993	7.01	7.01	7.04	7.04
1994	6.87	6.87	7.04	7.04
1995	8.47	8.47	8.61	8.61
1996	8.54	8.53	8.72	8.72
1997	7.72	7.73	7.93	7.94
1998	8.84	8.85	8.90	8.91
1999	8.75	8.75	8.81	8.81
2000	9.76	9.76	9.71	9.70
2001	10.36	10.36	10.32	10.32
2002	12.82	12.81	12.74	12.73
2003	14.65	14.64	14.70	14.69
2004	16.98	16.97	17.06	17.05
R^2	0.843	.8430	0.854	.8534
N	4995	4965	5190	5160

Table D-4
1990 Rate Model
Dependent Variable: Residential Rate

Coefficient Estimate Summary – Non-Gas Region				
	Base Model	**Exclude Blue Ridge**	**Include APS**	**Include APS Exclude Blue Ridge**
Coordinated Market	-1.87	-1.87	-1.474	-1.470
t-statistic	2.61	2.60	2.08	2.07
APS Region			-.297	-.290
t-statistic			.016	.016
1990 rate	.788	.788	.793	.793
	73.26	73.01	80.00	79.74
Total Sales	-.0000012	-.0000012	-.00000124	-.00000125
t-statistic	5.15	5.13	5.53	5.51
Average Residential Load	-1.36	-1.36	-1.258	-1.259
t-statistic	20.35	20.27	19.65	19.57
Proportion Industrial Load	-2.46	-2.45	-2.27	-2.26
t-statistic	3.50	3.48	3.28	3.26
Constant = 1990	31.59	31.61	29.98	29.99
1991	2.66	2.66	2.65	2.65
1992	4.35	4.35	4.40	4.39
1993	6.12	6.13	6.13	6.14
1994	6.35	6.36	6.51	6.51
1995	7.43	7.43	7.54	7.55
1996	6.88	6.88	7.02	7.03
1997	6.82	6.84	7.01	7.03
1998	6.84	6.85	6.86	6.87
1999	7.09	7.09	7.06	7.07
2000	7.47	7.47	7.33	7.33
2001	8.20	8.21	8.07	8.08
2002	9.90	9.90	9.77	9.77
2003	12.04	12.04	12.04	12.03
2004	13.90	13.90	13.93	13.92
R^2	.631	.630	.656	.656
N	4995	4965	5190	5160

Table D-5
Utility Dummy Model
Dependent Variable: Residential Rate

Coefficient Estimate Summary – East Coast Gas Region – Include A&N				
	Base Model	**Drop Industrial**	**Add Total Sales Squared**	**Drop Total Sales**
Coordinated Market	-1.613	-1.780	-1.924	-.780
t-statistic	2.63	2.90	3.09	1.31
Total Sales Squared	NA	NA	2.84×10^{-13}	
t-statistic	NA	NA	2.63	
Total Sales	-.0000044	-.0000045	-.0000086	NA
t-statistic	5.01	5.08	4.74	NA
Average Residential Load	-1.491	-1.390	-1.44	-1.53
t-statistic	9.80	9.19	9.47	10.02
Proportion Industrial Load	-8.95	NA	-8.73	-9.17
t-statistic	4.40		4.30	4.48
Constant = 1990	105.55	104.04	113.12	95.80
1991	.85	.90	.87	.82
1992	1.21	1.25	1.24	1.15
1993	3.39	3.36	3.45	3.28
1994	3.26	3.17	3.35	3.10
1995	4.00	3.91	4.14	3.76
1996	4.03	3.93	4.19	3.74
1997	4.09	3.95	4.27	3.77
1998	4.49	4.37	4.76	3.95
1999	4.39	4.21	4.71	3.71
2000	7.17	7.02	7.63	6.11
2001	11.22	10.99	11.69	10.13
2002	11.06	10.77	11.57	9.88
2003	14.17	13.92	14.69	12.93
2004	16.78	16.52	17.33	15.49
R^2	.948	.9472	.948	.947
N	1860	1860	1860	1860

Table D-6
1990 Rate Model
Dependent Variable: Residential Rate

Coefficient Estimate Summary – East Coast Gas Region – Include A&N				
	Base Model	**Drop Industrial**	**Add Total Sales Squared**	**Drop Total Sales**
Coordinated Market	-1.24	-1.23	-1.147	-1.179
t-statistic	1.79	1.79	1.65	1.72
1990 rate	.881	.880	.877	.880
	101.52	106.3	99.35	102.64
Total Sales	-.00000013	-.00000013	.0000007	
t-statistic	.68	.68	1.60	
Total Sales Squared			-9.8×10^{-14}	
t-statistic			2.09	
Average Residential Load	-.600	-.60	-.63	-6.11
t-statistic	8.15	8.15	8.40	8.47
Proportion Industrial Load	.122	NA	.230	.127
t-statistic	.12		.22	.12
Constant = 1990	14.25	14.29	14.599	14.376
1991	0.84	0.84	0.84	0.84
1992	1.10	1.09	1.09	1.10
1993	2.93	2.93	2.94	2.93
1994	2.55	2.55	2.55	2.55
1995	3.14	3.14	3.14	3.14
1996	2.80	2.80	2.81	2.80
1997	3.07	3.07	3.06	3.07
1998	3.01	3.01	3.00	3.00
1999	2.80	2.79	2.77	2.78
2000	5.01	5.00	4.96	4.96
2001	8.92	8.92	8.87	8.88
2002	8.34	8.34	8.30	8.30
2003	11.04	11.03	11.01	11..00
2004	13.76	13.76	13.72	13.72
R^2	0.892	0.893	0.893	0.892
N	1860	1860	1800	1860

Table D-7
Utility Dummy Model
Dependent Variable: Residential Rate

Coefficient Estimate Summary – Non-Gas Region – Exclude Blue Ridge									
					Include APS				
	Base Model	Drop Industrial	Add Total Sales Squared	Drop Total Sales	Base Model	Drop Industrial	Total Sales Squared	No Dummy	Drop Total Sales
Coordinated Market	-.877	-.814	-1.163	-.515	-.800	-.735	-.949	-.674	-.444
t-statistic	1.40	1.30	1.86	.83	1.29	1.18	1.66	1.18	.72
APS Region	NA	NA			.72	.736		NA	.683
t-statistic					.51	.52			.48
Total Sales	-.0000034	-..0000032	-.0000078		-.0000034	-.0000032	-.0000079	-.0000034	
t-statistic	4.82	4.54	6.93		4.90	4.59	7.06	4.90	
Total Sales Squared		NA	4.59×10^{-13}			NA	4.66×10^{-13}		
Total Sales			5.01				5.11		
Average Residential Load	-2.90	-2.91	-2.85	-2.94	-2.87	-2.88	-2.81	-2.87	-2.91
t-statistic	28.70	28.79	28.03	29.10	28.72	28.85	28.02	28.72	29.13
Proportion Industrial Load	4.37	NA	5.34	3.51	4.78	NA	5.74	4.79	3.95
t-statistic	2.72	-	3.31	2.19	3.05		3.65	3.05	2.53
Constant = 1990	120.25	120.48	121.10	119.54	119.70	119.98	120.52	119.69	118.98
1991	2.81	2.84	2.82	2.79	2.81	2.84	2.82	2.81	2.79
1992	4.21	4.26	4.26	4.18	4.27	4.32	4.32	4.27	4.24
1993	7.01	7.06	7.10	6.93	7.04	7.10	7.12	7.04	6.97
1994	6.87	6.92	6.98	6.76	7.04	7.11	7.15	7.04	6.94
1995	8.47	8.55	8.62	8.32	8.61	8.70	8.75	8.61	8.46
1996	8.53	8.61	8.72	8.33	8.72	8.81	8.90	8.72	8.53
1997	7.73	7.80	7.94	7.49	7.94	8.02	8.15	7.94	7.70
1998	8.85	8.89	9.14	8.52	8.91	8.97	9.18	8.90	8.59
1999	8.75	8.80	9.07	8.38	8.81	8.86	9.11	8.80	8.45
2000	9.76	9.80	10.12	9.33	9.70	9.75	10.04	9.69	9.28
2001	10.36	10.39	10.74	9.91	10.32	10.37	10.67	10.31	9.88
2002	12.81	12.83	13.20	12.32	12.73	12.77	13.12	12.73	12.24
2003	14.64	14.67	15.05	14.13	14.69	14.72	15.10	14.69	14.18
2004	16.97	17.01	17.42	16.42	17.05	17.10	17.50	17.06	16.50
R^2	.8430	.8428	0.844	.8423	.8534	.8532	.8542	.8534	.8527
N	4965	4965	4965	4965	5160	5160	5160	5160	5160

Table D-8
1990 Rate Model
Dependent Variable: Residential Rate

Coefficient Estimate Summary – Non-Gas Region – Exclude Blue Ridge									
					Include APS				
	Base Model	Drop Industrial	Add Total Sales Squared	Drop Total Sales	Base Model	Drop Industrial	Add Total Sales Squared	No Dummy	Drop Total Sales
Coordinated Market	-1.87	-1.89	-1.953	-1.790	-1.470	-1.500	-1.587	-1.50	-1.36
t-statistic	2.60	2.63	2.72	2.48	2.07	2.11	2.24	2.24	1.92
APS Region					-.290	-.091	-.232	NA	-.276
t-statistic					.016	-.05	.13		-.15
1990 rate	.788	.800	.792	.787	.793	.803	.798	.793	.790
t-statistic	73.01	77.99	73.53	72.73	79.74	84.97	80.36	80.08	79.35
Total Sales		-.0000034	-.0000036		-.00000125	-.0000014	-.0000039	-.00000125	
t-statistic	5.13	6.01	7.94		5.51	6.37	8.60	5.51	
Total Sales Squared			3.40×10^{-13}				3.66×10^{-13}		
t-statistic			6.21				6.74		
Average Residential Load	-1.36	1.32	-1.236	-1.437	-1.259	-1.230	-1.124	-1.259	-1.342
t-statistic	20.27	19.96	17.54	22.04	19.57	19.29	16.74	19.57	26.41
Proportion Industrial Load	-2.45	NA	-2.04	-3.23	-2.26	NA	-1.79	-2.25	-3.09
t-statistic	3.48	--	2.89	4.67	3.26		2.59	3.25	4.55
Constant = 1990	31.61	29.98	30.29	32.42	29.99	28.58	28.55	29.98	30.91
1991	2.66	2.64	2.66	2.67	2.65	2.63	2.65	2.65	2.65
1992	4.35	4.32	4.38	4.33	4.39	4.37	4.42	4.39	4.38
1993	6.13	6.09	6.11	6.14	6.14	6.10	6.13	6.14	6.16
1994	6.36	6.32	6.39	6.35	6.51	6.48	6.54	6.51	6.51
1995	7.43	7.37	7.45	7.44	7.55	7.49	7.56	7.55	7.55
1996	6.88	6.82	6.88	6.89	7.03	6.97	7.02	7.03	7.04
1997	6.84	6.79	6.89	6.80	7.03	6.98	7.09	7.03	6.99
1998	6.85	6.80	6.87	6.83	6.87	6.83	6.89	6.88	6.85
1999	7.09	7.05	7.14	7.05	7.07	7.03	7.12	7.07	7.02
2000	7.47	7.42	7.50	7.43	7.33	7.28	7.36	7.33	7.28
2001	8.21	8.16	8.25	8.15	8.08	8.03	8.12	8.08	8.02
2002	9.90	9.84	9.90	9.86	9.77	9.71	9.78	9.77	9.72
2003	12.04	11.98	12.06	11.98	12.03	11.98	12.07	12.03	11.97
2004	13.90	13.83	13.92	13.85	13.92	13.85	13.95	13.91	13.86
R^2	.630	.6297	.6334	.6286	.656	.6549	.6586	.656	.6536
N	4965	4965	4965	4965	5160	5160	5160	5160	5160

Table D-9
Combined Sample 1
Dependent Variable: Residential Rate

Coefficient Estimate Summary – Include A&N, Drop Blue Ridge						
	Utility Dummy Model	**Total Sales Squared**	**Drop Total Sales**	**1990 Rate Model**	**Total Sales Squared**	**Drop Total Sales**
Coordinated Market	-1.27	-1.48	-.734	-1.874	-1.978	-1.695
t-statistic	2.85	3.32	1.68	3.67	3.87	3.33
1990 rate				.838	.842	.835
t-statistic				120.79	120.25	121.04
Total Sales	-.0000036	-.0000073		-.00000054	-.0000016	
t-statistic	6.47	7.66		3.61	4.96	
Total Sales Squared		3.24×10^{-13}			1.35×10^{-13}	
t-statistic		4.78			3.71	
Average Residential Load	-2.48	-2.44	-2.52	-1.08	-1.03	-1.11
t-statistic	29.25	28.56	29.68	21.29	19.77	22.50
Proportion Industrial Load	-1.07	-.45	-1.71	-1.55	-1.42	-1.82
t-statistic	.84	.36	1.35	2.67	2.44	3.16
Constant = 1990	114.83	115.56	114.04	23.91	23.32	24.43
1991	.94	.96	.92	-.52	-.47	-.59
1992	1.36	1.39	1.32	-.23	-.18	-.29
1993	3.75	3.79	3.66	1.75	1.79	1.69
1994	3.73	3.79	3.61	1.46	1.50	1.40
1995	4.54	4.63	4.34	2.09	2.13	2.02
1996	4.96	5.07	4.73	1.94	1.96	1.87
1997	4.63	4.75	4.38	2.06	2.11	1.99
1998	5.34	5.51	4.93	2.27	2.31	2.16
1999	5.04	5.24	4.53	2.12	2.18	1.99
2000	8.08	8.37	7.32	4.75	4.83	4.56
2001	12.08	12.39	11.31	8.70	8.78	8.51
2002	12.21	12.52	11.36	8.29	8.35	8.10
2003	15.84	16.17	14.95	11.20	11.25	11.02
2004	18.22	18.57	17.29	13.84	13.89	13.64

Table D-9 (Continued)
Combined Sample 1
Dependent Variable: Residential Rate

Coefficient Estimate Summary – Include A&N, Drop Blue Ridge						
	Utility Dummy Model	**Total Sales Squared**	**Drop Total Sales**	**1990 Rate Model**	**Total Sales Squared**	**Drop Total Sales**
Non-Gas						
1991	2.80	2.82	2.78	3.14	3.12	3.16
1992	4.30	4.34	4.26	4.86	4.85	4.88
1993	6.84	6.91	6.75	6.45	6.43	6.48
1994	6.81	6.91	6.69	6.74	6.74	6.76
1995	8.30	8.44	8.14	7.71	7.70	7.73
1996	8.21	8.38	7.99	7.04	7.03	7.07
1997	7.62	7.82	7.36	7.13	7.15	7.14
1998	8.45	8.71	8.08	6.94	6.95	6.95
1999	8.46	8.75	8.04	7.23	7.26	7.22
2000	9.31	9.64	8.82	7.49	7.51	7.48
2001	9.95	10.29	9.45	8.26	8.28	8.24
2002	12.19	12.56	11.65	9.81	9.82	9.80
2003	14.12	14.49	13.56	12.00	12.02	11.98
2004	16.34	16.75	15.73	13.77	13.79	13.75
R^2	.9037	.9040	.9031	.7804	.7808	.780
N	6825	6825	6825	6825	6825	6825

Non-gas Year t = 1 for utility in non-gas dependent region, year t
Year t = 1 for utility in gas dependent region, year t