Commonwealth of Virginia

State Corporation Commission

Report to the Commission on Electric Utility Restructuring of the Virginia General Assembly

And the Governor of the Commonwealth of Virginia

<u>Status Report: The Development of a Competitive Retail Market for Electric Generation within the Commonwealth of Virginia</u>

Pursuant to Section 56-596 of the Code of Virginia

September 1, 2005

CLINTON MILLER
CHAIRMAN

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STATE CORPORATION COMMISSION

September 1, 2005

TO: The Honorable Mark R. Warner
Governor, Commonwealth of Virginia

The Honorable Thomas K. Norment, Jr.
Member, Senate of Virginia
Chairman, Commission On Electric Utility Restructuring
and
Members of the Commission On Electric Utility Restructuring

The State Corporation Commission is pleased to transmit its report regarding the advancement of competition in Virginia as required by Section 56-596 of the Virginia Electric Utility Restructuring Act.

This report, required annually by September 1, provides information on the status of competition in the Commonwealth, the status of the development of regional competitive markets, and the Commission's recommendations to facilitate effective competition as soon as practical.

Respectfully submitted,

Original signed by

Clinton Miller
Commission Chairman

Original signed by

Theodore V. Morrison, Jr.
Commissioner

Original signed by

Mark C. Christie
Commissioner

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Executive Summary and Overview

It has been over six years since the Virginia General Assembly passed the Virginia Electric Utility Restructuring Act ("Restructuring Act" or "Act")[1], and a little more than half-way to the end of the transition period in 2010 as set forth in the Act. Section 56-596 of the Act requires the Virginia State Corporation Commission ("SCC") to report to the Commission on Electric Utility Restructuring ("CEUR") and the Governor by September 1 of each year on the status of competition in the Commonwealth, the status of the development of regional competitive markets and the SCC's recommendations to facilitate effective competition in the Commonwealth as soon as practicable. This section of the statute also requires the SCC to report any recommendations of actions to be taken by the General Assembly, electric utilities, suppliers, generators, distributors, and regional transmission entities that the SCC considers to be in the public interest.

The SCC offers its fifth annual Report pursuant to the requirements of the Act consisting of three parts. Part I is a description of evolving regional retail and wholesale markets prepared by Dr. Kenneth Rose, Senior Fellow, Institute of Public Utilities at Michigan State University. Part II reports on the status of retail access and competition in the Commonwealth. Part III presents the SCC's view of the current competitive marketplace, including comments offered by stakeholders responding to an annual SCC solicitation of potential recommendations and actions to facilitate effective competition.

[1] Virginia Electric Utility Restructuring Act, Chapter 23 (§ 56-576 et seq.) of Title 56 of the Code of Virginia.

Part I of this Report contains detailed data and information on restructured wholesale and retail electricity markets around the United States. The economic health of these markets is questionable. As generating companies continue to face difficult financial conditions, Dr. Rose reports that there remains strong concern that significant market power is being exercised in all wholesale markets that have been independently analyzed. The coincidence of these two phenomena -- the alleged exercise of market power that serves to increase market prices and thus the returns to generators, coupled with the widespread financial distress in the industry which should be alleviated by the exercise of market power -- is puzzling. These two coincident results, taken together, illustrate the difficulty of fashioning electricity markets that ensures both the provision of safe and reliable service and the vigorous competition needed to forestall any exercise of market power.

Dr. Rose's Part I also provides extensive descriptions of retail markets on a state-by-state basis. He reports that 16 states and the District of Columbia continue to allow retail access. Several states have decided to delay retail access, restrict retail access to only larger customers or otherwise curtailed their retail access efforts. Of the 17 jurisdictions that allow retail access, there is little, if any, effective retail competition for electric service in the residential and small commercial market. Part I does show competitive penetration among larger customers in some jurisdictions, such as New York and Texas. However, at this point in time, it is premature to determine the extent of any benefit to these larger customers.

On the basis of the extensive information submitted by Dr. Rose, the SCC concludes that, while retail access is widely available in many jurisdictions, vigorous retail competition has yet to develop. This national result, when combined with results obtained here in the Commonwealth as detailed in Part II of this Report, still causes serious concern regarding the ability of retail electric competition to provide, at the present time, lower prices for Virginians than would have been charged under the traditional regulation of the industry.

Part II of the Report focuses on activities in Virginia related to retail access and resulting competition in the electricity market over the past year. It also reviews the SCC's efforts to develop a proper infrastructure to accommodate competition and to prepare Virginians for consumer choice for generation, as directed by the Act. During the past year the SCC has continued to implement the Restructuring Act. At the present time, about 3.2 million electricity customers in Virginia have the right to choose an alternative supplier of electricity.

As we reported last year, the right to choose has still not evolved into the ability to choose. While it is clear that the SCC, the utilities and the various stakeholders have effectively enabled retail access in Virginia, there remains little competitive activity in the Commonwealth. We understand that many suppliers still perceive little economic incentive to enter the Virginia retail market. No competitive service provider is offering energy priced so that switching customers may save money. Currently, one supplier continues to serve slightly below 1,600 residential customers and 20 small commercial customers in Dominion Virginia Power's ("Dominion" or "DVP") northern service area with an environmentally-friendly renewable power offer. This service is more expensive than DVP's price-to-compare and the number of customers taking such service has declined from last year's report. Again, as detailed in Part I, this lack of activity is not unique to the Commonwealth; in other states currently offering retail access, few customers have the option to purchase power at a price lower than their incumbent's price-to-compare.

Over the past twelve months, the SCC, aided by the incumbent utilities and interested stakeholders, continued to make strides in preparing the Commonwealth for the arrival of competition for the generation component of electric service. Work groups coordinated by the Staff continue to assist the SCC and provide the foundation for retail access by examining many issues. The SCC appreciates the time and effort of the respondents that have participated with these work groups. The Commission has issued orders during the past year relating to topics such as the delay of default service, market price/wires charge determination, market-based costs, regional transmission organizations ("RTO"), and pilot programs within Dominion's territory.

Part III of the Report presents comments advanced by various stakeholders as means of facilitating effective competition in the Commonwealth. It also discusses the Commission's continued actions to implement the elements of the Restructuring Act and the activities to properly align processes and systems to foster effective competition.

As outlined in this Report, the problems that are impeding the development of retail competition in Virginia and other regional markets continue unabated. In terms of the existence of retail competition, little, if anything, has changed since last year. There still appears to be universal agreement that before a viable competitive retail market develops in the Commonwealth there must be a robust wholesale market under an operational and independent regional transmission organization. Now that the Virginia utilities are integrated into PJM, time and experience will determine if such a marketplace will indeed develop. We currently have the basic rules, systems, and procedures in place to harmonize retail access and will continue to monitor market conditions and react accordingly.

ACRONYMS

A&N	A&N Electric Cooperative
ACC	Arizona Corporation Commission
AEI	American Energy Institute
AEP	American Electric Power
AP	Allegheny Power
APCo	Appalachian Power Company
BARC	BARC Electric Cooperative
BGS	basic generation service
BHE	Bangor Hydro-electric Company
CBEC	Craig-Botetourt Electric Cooperative
CEC	Community Electric Cooperative
CEUR	Commission on Electric Utility Restructuring
CGV	Columbia Gas of Virginia
CSP	competitive service provider
CTC	competitive transition charge
CVEC	Central Virginia Electric Cooperative
DCPSC	District of Columbia Public Service Commission
DP&L	Delmarva Power & Light Company
DEPSC	Delaware Public Service Commission
DEQ	Department of Environmental Quality
DVP	Dominion Virginia Power
EDI	electronic data interchange
ESCO	energy service company
FERC	Federal Energy Regulatory Commission
FREDI	First Regional Electronic Data Interchange
ICAP	installed capacity market of PJM
ICC	Illinois Commerce Commission
IEEE	Institute for Electrical and Electronic Engineers
ICC	Illinois Commerce Commission
IURC	Indiana Utility Regulatory Commission
KU	Kentucky Utilities
kW	kilowatt
KPSC	Kentucky Public Service Commission
LDC	local distribution company
LMP	locational marginal price
MEC	Mecklenburg Electric Cooperative
MIPSC	Michigan Public Service Commission
MMU	Market Monitoring Unit of PJM
MDPSC	Maryland Public Service Commission
MW	megawatt
NAESB	North American Energy Standards Board
NARUC	National Association of Regulatory Utility Commissioners
NCUC	North Carolina Utilities Commission

NEM	National Energy Marketers Association
NJBPU	New Jersey Board of Public Utilities
NNEC	Northern Neck Electric Cooperative
NOPEC	North East Ohio Public Energy Council
NOPR	Notice of proposed rulemaking
NOVEC	Northern Virginia Electric Cooperative
ODCFUR	Old Dominion Committee for Fair Utility Rates
ODEC	Old Dominion Electric Cooperative
ODP	Old Dominion Power
PAPUC	Pennsylvania Public Utilities Commission
PES	Pepco Energy Services
PE	Potomac Edison
PGEC	Prince George Electric Cooperative
PJM	PJM Interconnection, LLC
POLR	provider of last resort
PUCO	Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas
REC	Rappahannock Electric Cooperative
REP	retail electric provider
ROA	retail open access
RTE	regional transmission entity
RTO	regional transmission organization
S&P	Standard & Poor's Ratings Service
SCC	Virginia State Corporation Commission
SERC	Southeastern Reliability Council
SOS	standard offer service
SPP	Southwest Power Pool
SSEC	Southside Electric Cooperative
SVEC	Shenandoah Valley Electric Cooperative
T&D	transmission and distribution
UBP	Uniform Business Practices
UCAP	unforced capacity market of PJM
VCCC	Virginia Citizens Consumer Council
VCFUR	Virginia Committee for Fair Utility Rates
VEC	Virginia Energy Choice
VEPA	Virginia Energy Providers Association
VIPP	Virginia Independent Power Producers
VMDA	Virginia, Maryland, & Delaware Association of Electric Cooperatives
WGES	Washington Gas Energy Services
WGL	Washington Gas Light
WVPSC	West Virginia Public Service Commission

PART I

STATUS OF THE DEVELOPMENT OF REGIONAL COMPETITIVE MARKETS

2005 PERFORMANCE REVIEW OF ELECTRIC POWER MARKETS

2005 Performance Review of Electric Power Markets
Update and Perspective

Review Conducted for the Virginia State Corporation Commission*

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August 23, 2005

*This report was conducted under contract with the Virginia State Corporation Commission as Part I (of three parts) of the Commission's annual report to the Virginia General Assembly on the advancement of a competitive retail electricity market in the Commonwealth of Virginia. The views expressed here are those of the authors and do not necessarily reflect the views or opinions of the Virginia State Corporation Commission.

Executive Summary

Retail Market Overview

Currently, most states have decided to either postpone their efforts to implement retail access or have stopped considering adopting it altogether. Sixteen states and the District of Columbia have fully implemented their legislation and commission orders and currently allow full retail access for all customer groups. Two states allow retail access for larger customers only; Nevada, which modified its original law to limit access to just larger customers and Oregon, whose original law limited retail access to larger customers. Six states that passed restructuring legislation later delayed, repealed, or indefinitely postponed implementation. Oklahoma and West Virginia passed restructuring legislation but stopped short of implementation, Arkansas and New Mexico have repealed their laws, California suspended the retail access program it already had implemented in September 2001, more than one year after the beginning of the California and western power crisis. Montana has also been dealing with the severe aftermath of the western power crisis, and extended the transition period to retail access for smaller customers. Montana implemented retail access for large industrial customers in July 1998, but residential access originally scheduled to begin by July 2002 has been postponed to 2027.

Twenty six states are no longer considering restructuring at this time. None of these states appear to be working in any meaningful way toward passage at this time. No state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning to take shape. The states that did not pass legislation, but were in the process of considering it, either gradually lessened their efforts to allow time to consider what was occurring in the West or they abruptly stopped any activity that was ongoing at the time. Thus, a total of 34 states have repealed, delayed, suspended, limited retail access to just large customers, or are now no longer considering retail access.

Only two states have residential load “switching” greater than 10 percent in 2005. One state is Ohio where most of the residential switching in the state has been through the state's aggregation program. The other is Texas that is now the most active state in the country in terms of residential customers choosing a supplier. Most states are well below five percent. Nine states are at or near zero percent.

The percentage of commercial and industrial load served by competitive suppliers in early 2005 was considerably higher than for residential load. Six states, D.C., Illinois, Massachusetts, Maine, New York, and Texas, had a larger customer group (either commercial, industrial, or combined commercial and industrial) with greater than 50 percent of load served by competitive suppliers. Two were above 80 percent. Four states had no larger customer category above ten percent.

In terms of total state load served by competitive suppliers, five states had greater than 30 percent of the total state load being served by competitive suppliers, D.C., Illinois, Maine, New York, and Texas. However, six states had less than ten percent of the total state load being served by competitive suppliers.

Evaluation of the Wholesale Market Results to Date

Most observers of electric industry restructuring would agree that it has been more difficult and more complex than believed when the process began in the 1990s. Because of the technical nature of electric supply and the many functions that remain regulated, the task was likely to be difficult. Difficulty and complexity are not problems in themselves, but may lead to unintended consequences that designers could not have anticipated. The current Regional Transmission Organization (RTO) structure that has emerged was not created through a specific design plan. Instead, it evolved through a series of Federal Energy Regulatory Commission (FERC) orders, responses by the RTOs themselves, and the clash of interest groups in the FERC proceedings. Of course, the industry structure prior to the start of restructuring was also very influential, that is, the generation, distribution, and transmission infrastructure that was built over decades and the industry-specific events that preceded restructuring.

Just how competitive a particular industry is depends on three general structural characteristics: (1) the market concentration or market share of the suppliers in the industry, (2) the ease with which alternative suppliers can enter a market, and (3) the overall market demand characteristics of the product. By examining these three characteristics together, the degree of competitiveness of any industry or market can be determined. In the wholesale electric supply industry, all three characteristics clearly play an important role. Markets are very concentrated for most geographic regions of the country, even for multi-state wholesale regions. Market entry from other firms requires time to build new generation and is limited from outside the area by transmission constraints, which also require time to relieve. Mass storage of electricity for later use during peak hours is generally impractical for many regions of the country. Also, demand for electricity is very inelastic, particularly in the short-run (less than one year) since customers have few practical alternatives and the long life of major electrical appliances makes it difficult to respond to price changes quickly for most customers.

The possibility of coordinated interaction and tacit collusion could have particular relevance for electricity markets, given the nearly continuous interaction that firms have in RTO and ISO markets. A merger of firms of any size within the same RTO means fewer firms in the market and makes coordination more possible. In its analysis of the Exelon/PSEG merger, FERC did not examine the possibility of collusion. Also, the ISO and RTO market monitors do not examine this possibility either.

Strategic bidding and withholding are clearly issues that need to be examined. There are academic papers that suggest that strategic bidding could happen and how it could (and perhaps actually does) happen in LMP markets. While academics have been studying this issue for a few years, it is not purely an academic exercise. The 2000-2001 western power crisis period demonstrated that it can happen. However, outside of the analysis on that crisis, no analysis has been done that studies actual bidding behavior in other ISO or RTO markets. However, the academic discussion and what bidders could or may be able to do in these markets, suggests that, at the very least, the issue of strategic bidding needs to be studied. As another academic paper warns, "[g]iven the cost of mistakes, e.g., the California electricity market in 2000, a more than incremental change in a market design requires careful analysis, especially of how the participants can outwit the designers."

All these characteristics and features taken together suggest that the market structure that is emerging is certainly not perfectly competitive, an impossible standard for any market to reach, nor could the structure be characterized as a pure monopoly, that is, one supplier – although that may occur in some local areas or subregions of an RTO or ISO under certain circumstances. Rather, the structure that is suggested is one of an oligopoly, defined as a market where there are a few firms supplying all or most of the output.

Recent Events

Two significant recent events have occurred that will likely have a material impact on the development of wholesale markets across the country. First, the Federal Energy Regulatory Commission (FERC) approved the Exelon merger with PSEG, without a hearing and second was the passage of the Energy Policy Act of 2005, which included the repeal of the Public Utility Holding Company Act of 1935 (PUHCA). The repeal of PUHCA and its impact on FERC's merger reviews will depend on FERC's implementation of the new legislation. However, most industry observers seem to agree that this will almost certainly lead to more and larger mergers, and more combination energy companies (of electric supply and distribution, natural gas, oil, etc). Together these events suggests that it is likely that there will be even greater concentration of the industry, and in particular, increased concentration of ownership of generation resources. If the result is an increase in the concentration of generation ownership, then, as economic theory suggests, the result will be less competitive wholesale electricity markets.

It is not known with any degree of certainty if there is significant market power in PJM or other ISO and RTO markets. The analysis conducted so far of the ISOs and RTOs themselves is insufficiently detailed enough to warrant a conclusion one way or the other. The conditions are such that it is possible that considerable amount of market power could be exercised. Only an independent analysis will help shed some light on the issue.

An independent analysis of the wholesale market and its potential impact needs to be conducted in a comprehensive and rigorous manner. This is needed to characterize the condition of regional wholesale markets and determine the likely outcome of the regional markets on retail prices. This study needs to be a structural analysis to determine whether there is in fact a sufficient level of competition among suppliers or, as discussed, they are operating closer to an oligopoly structure with tacit collusion.

This type of analysis is impossible without access to detailed price and bidding data. Unfortunately, data restrictions limit access to external analysis. Either states or FERC or other federal agencies, needs to mandate such a study to allow the required data access. This analysis needs to be independent of the ISOs and RTOs so that it is not influenced by any single or group of market participants that obviously would have an interest in the outcome of the analysis. Until this is done, we are “flying blind” and operating on the assumption that we have sufficient altitude and that there are no mountain ranges in front of us.

State transition periods have been ending and many of these states are seeing significant price increases. In these cases, retail customers are seeing the impact that higher fuel prices are having on wholesale electricity prices. However, while fuel costs have increased across the country, not all states have seen the same impact from these increases on their retail electric prices. According to EIA figures, the national average retail price for all sectors from 2004 through April 2005 increased by 3.6 percent. This suggests that, nationally, the full impact of fuel cost increases are not affecting retail rates at the same pace.

In the case of retail customers in restructured states where the transition period has ended and their price is now determined in the wholesale market, the customers are now taking the brunt of the impact that increased fuel prices are having on wholesale prices. It appears that, from the data so far, most retail customers (especially residential) in restructured states where the transition period has ended and the price is now based on the wholesale market, are seeing prices increase faster than in the non-restructured states or states still in transition with a price cap. At best, at this point in time, no discernable overall benefit to retail consumers can be seen from restructuring.

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Part A

Results and Update of Electric Power Industry Restructuring Activities

Introduction

This is the fifth year that a section of the SCC's report to the Virginia General Assembly and the Governor has been done on the development and performance of wholesale and retail electric power markets around the country, as required under the Virginia Electric Utility Restructuring Act. Last year's report was comprehensive in that it covered the developments in all regions of the country. Past reports have all provided detailed descriptions of the development of the regional wholesale markets and state retail markets. This included the formation and growth of the Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), descriptions of the markets they operate, and analysis of the performance of these regional wholesale markets. Also included in past reports was the development of state retail markets, such as shopping status, offers to residential customers, and details on state legislation and regulatory commission implementation.

This year's report provides an overview and update of previous performance review reports on the wholesale and retail market developments and a perspective on what has been learned so far. The report is divided into two parts. Part A covers the results so far from industry restructuring and provides updates of wholesale prices and retail market developments, including retail prices that are now beginning to show the impact from restructuring. Part B provides a perspective on the developing industry structure so far and how it relates to the legislative and regulatory goal of fostering the development of competitive wholesale and retail markets.

Goals of Restructuring and Results to Date

Among the principal reasons for the movement away from the traditional cost-based regulation and toward generation competition and retail access was the belief that competition would provide better incentives to control costs and that these cost savings would be passed on to consumers–resulting in lower prices for all customer classes. Other reasons for favoring a move away from cost-based regulation included increased use of innovative technologies in generation and the belief that it would give customers more options in terms of price, fuel source, and service.

In the mid-1990s, it was common for advocates for competition to list the advantages, as they saw it, in moving from regulated monopolies to competitive markets. In testimony before Congress, a spokesperson for the Electric Power Supply Association[1] noted:

> Competition . . . can be expected to:
> - Provide the lowest prices possible.
> - Allow all customers, for the first time ever, to choose their provider of electricity.
> - Improve technology and services.
> - Enhance reliability.
> - Improve environmental performance.
> - Protect consumers from anti-competitive behavior and market power abuses.
> - Strengthen the competitiveness of American industry.

In 1996, states began to pass restructuring legislation and FERC issued its Order 888, which required transmission open access. Nearly a decade has passed since these events occurred and seven years since several states began to open their retail markets in 1998. Attempts are now being made to assess how well these efforts have progressed toward moving to competitive electricity markets. Given the variety of views on the subject, it is not too surprising that the assessments vary from showing no benefit to significant savings to consumers from restructuring. While it will take time to see to what extent the benefits in the above list are realized, if at all, the focus here will be on the first item, retail prices.

[1]Written statement of Steven D. Burton, speaking before the House Judiciary Committee Oversight Hearing on Anti-trust Aspects of Electricity Deregulation, June 4, 1997. Steven D. Burton was Senior Vice President and General Counsel for Sithe Energies, Inc. and Chair, Electric Power Supply Association (EPSA).

A recent study claims that consumers have benefitted $15.1 billion from wholesale competition in the Eastern Interconnection from 1999 through 2003.[2] The study compares a "with wholesale competition" case to a "without wholesale competition" case to estimate the benefit from competition. The benefits, according to the study, come from two sources, fuel and variable O&M cost savings (almost $6.4 billion for the five year period; this is the fuel and variable O&M cost difference between the two cases) and costs that are said to be avoided but that would have been incurred if the power had been supplied under cost-of-service regulation.

There are, however, at least three serious limitations to the analysis. First, the study assumed that there are no competitive energy purchases under the "without wholesale competition." Energy purchases by regulated utilities predate the industry restructuring that began in the 1990 by many years. While there are more energy purchase sales in recent years, it is unrealistic to assume none would occur at all in a regulatory scenario. Secondly, and perhaps more seriously, most of the "savings" are from the lower cost for competitively supplied power, but this cost does not include the loss to competitive suppliers of about $11.1 billion. This "savings" is, at best, a temporary one, since it is reasonable to expect that new suppliers will not enter the market to lose money. If the full cost was added (not just the revenue earned), the savings for the five year period would be about $4 billion. Since this is for five years and for the entire Eastern Interconnection,[3] this is not a substantial sum. For comparison, PJM's billings alone for 2005 are estimated to be about $13 billion. Finally, there may well be fuel and variable O&M cost savings from competition that would not occur under regulation, but there are no guarantees that any of those savings are being passed on to consumers.

In contrast, a recent publication by the American Public Power Association (APPA) stated, "it is time to take stock" of the Federal Energy Regulatory Commission's

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[2]Global Energy Decisions, "Putting Competitive Power Markets to the Test, The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies," July 2005. A copy of the report was obtained from http://www.globalenergy.com/competitivepower/ .

[3]This includes the entire U.S. east of the Rocky Mountains, except Texas.

(FERC) restructuring policies and make “substantial ‘mid-course corrections.’”[4] The APPA recommends that FERC “reorient its policies to make sure electric consumers in fact—not just in economic theory—benefit from electric restructuring.” The APPA paper focuses on FERC’s Regional Transmission Organization (RTO) policies. It notes that concerns stem from

> APPA members in RTO regions report substantial, across-the-board problems with spiraling RTO costs, unaccountable RTO governance, and ever-increasing provision of RTO services through questionable market mechanisms. These APPA members are unable to obtain or even retain long-term firm transmission service at just and reasonable rates. This is impairing their ability to enter into the long-term generation resource arrangements they need to provide reliable and affordable electric service to their end-use customers.

The costs of RTO and ISO operations have been escalating steadily in recent years. An analysis that collected and compared the annual operating costs of the six RTOs and ISOs currently in operation found that these costs totaled over $1 billion in 2004 (in 2003 dollars).[5] Total annual operating costs have more than doubled since 2000. All the RTOs and ISOs have seen steady cost increases, except the California ISO that decreased in its 2004 annual operating cost from 2003. PJM and the Midwest ISO both exceeded $200 million annual operating costs in 2004 (again, in 2003 dollars). The California ISO had the highest operating cost in 2004 of the six organizations. Obviously, for the period reported, 1997 to 2004, the RTOs and ISOs have greatly expanded their operations in terms of both geographic size and the scope of their operations. Also, in terms of costs per MWh, these costs are relatively modest. For example, the PJM annual cost is about 60 cents/MWh in 2004 – however, this has also doubled since 2000. The average annual growth rate of the total annual operating costs, using these figures from 1998 through 2004, is nearly 29 percent, and these

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[4]American Public Power Association, “Restructuring at the Crossroads: FERC Electric Policy Reconsidered,” December 2004, p. iii.

[5]Margot Lutzenhiser, “Comparative Analysis of RTO/ISO Operating Costs,” August 17, 2004, presentation, Public Power Council.

costs increased over 350 percent overall during this period. If such costs continue to escalate at that rate, RTO and ISO operating costs will become an even more significant policy concern.

While it is important to track industry costs, the bottom line for consumers is what they pay for power and whether there is any discernable benefit from restructuring that can be seen so far. A paper that examined industrial electricity prices,[6] found no benefit to industrial customers from electric industry restructuring. This analysis used EIA data from 1990 through 2003 and concludes that "there is no correlation between restructuring or regulation and improvement in the annual rate of price change" and that "[r]estructuring in the electricity industry has not led to lower industrial prices, nor to decreased rates of annual price increases."[7]

Comparing state industrial consumer prices, the author found that the annual percentage change in industrial prices from one month after the end of the phase-in period through 2003 for all restructured states increased by 0.5 percent. If Maine is removed from the group, the annual percentage increases to 1.7 percent annual percent change.[8] By comparison, prices in regulated states in the continental U.S. for the period 2001 through 2003 increased by 0.3 percent. Regionally, prices in the three areas examined all increased by about two percent annually, 1.8 percent for western restructured states (Arizona, California, Montana, and Oregon), 2.1 percent for Ohio Valley restructured states (Illinois, Ohio, Pennsylvania), and 2.0 percent for New England (New England states without Maine plus New York). Western regulated states' prices increased by 1.0 percent, upper Midwest regulated states' prices increased by 1.3 percent annually, lower Midwest regulated states' prices *decreased* by 1.8 percent

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[6]Jay Apt, "Competition Has Not Lowered US Industrial Electricity Prices," Carnegie Mellon Electricity Industry Center, Working Paper CEIC-05-01, 2005. The paper is available at, www.cmu.edu/electricity.

[7]Apt, p. 8.

[8]Page 6 of the Apt study notes that Maine is dependent on natural gas-fired electric generation, and that "[p]rices in that state began to rise in 2000, but have fallen significantly since . . . completion of two natural gas pipelines from the Sable Island field off Nova Scotia." As summarized later in this report in the state summaries, Maine's retail prices for 2005 have begun to increase significantly.

annually, Ohio Valley regulated states' prices increased 2.5 percent, prices in regulated Vermont *decreased* by 0.8 percent, and southern regulated states (Louisiana and Arkansas through Florida and up to North Carolina) also had *decreased* prices of 0.8 percent annually.

The author summarizes a number of factors that may increase costs and prevent the benefits of competition from reaching consumers.[9] These include noncompetitive markets, wholesale market clearing prices that are paid to all generators, RTO/ISO operational costs, and the increased cost-of-capital that competitive suppliers face.

More recent state price data suggest that prices in restructured states may still be increasing faster than states that did not restructure. A small survey of industrial rates included 15 restructured state utilities and nine non-restructured state utilities.[10] Overall, industrial rates in the sample increased by 5.2 percent from 2004 to 2005. Four states had double digit increases – all in restructured states – Maryland (BG&E with a 33 percent increase), New York (Con Edison with a 15 percent increase), and two companies in Texas (Reliant Energy with a 13 percent increase and Texas Utilities with a 12 percent increase). Eleven states had utilities above the survey average increase, six were restructured states (including the top four listed above) and five were non-restructured states. Eight states had decreases in the price, five of these were less than one percent. However, the largest decrease was in a restructured state – New Jersey utility Public Service Electric & Gas with a 3.5 percent decrease, but that state started with the fifth highest rate in the survey.

[9]These factors are discussed in more detail in, Lester B. Lave, Jay Apt, and Seth Blumsack, "Rethinking Electricity Deregulation", *The Electricity Journal*, 17:8 (2004) at 11-26.

[10]The survey sampled 24 large investor-owned utilities' pricing for industrial customers based on a monthly usage of 450,000 kWh, monthly demand of 1,000 kW, operating power factor of 85 percent and customer-owned transformer equipment. The survey results were obtained from NUS Consulting Group, http://www.nusconsulting.com/ , April 2005.

<u>**Regional Wholesale Market Update**</u>

Mid-Atlantic/PJM

Figure 1 shows average daily prices for peak hours (day-ahead and real-time markets) for PJM, as well as the AEP Dayton Hub and the ComEd Zone, which was added to PJM in 2004. There is a slow but steady convergence of prices between PJM and ComEd in the five quarter period shown in the graph. Table 1 shows the maximum, average, and minimum peak hour prices in the day-ahead and real-time markets. Prices in ComEd started well below PJM, but by late 2004, prices were much more comparable. This convergence is demonstrated more clearly in Figure 2 on the next page.

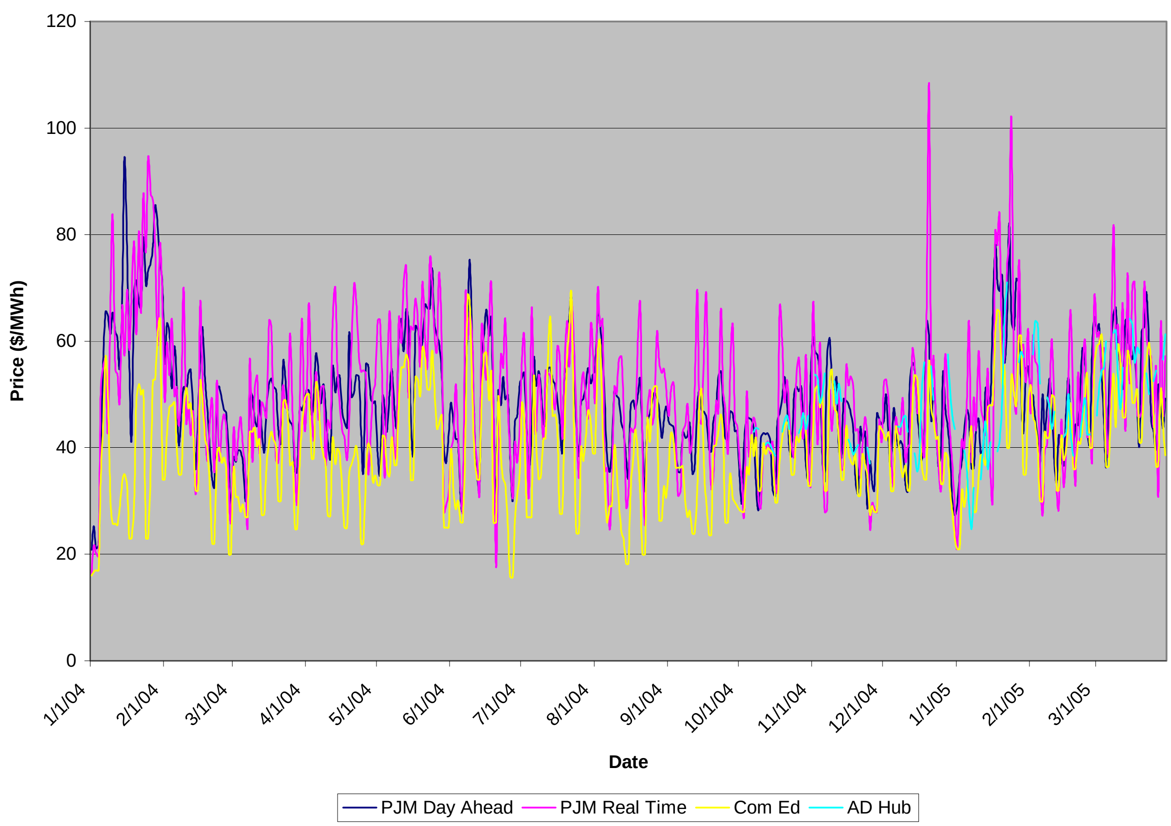


Figure 1. Daily average peak hour prices for PJM regions – PJM (day-ahead and real-time), ComEd region, and AEP Dayton Hub.
Source: PJM for PJM day-ahead and real-time, *Platts Megawatt Daily* for ComEd, and ICE for AD Hub.

Table 1. Peak hour prices in the PJM day-ahead and real-time markets.

Hour	700	800	900	1000	1100	1200	1300	1400	1500	1600	1700	1800	1900	2000	2100	2200
Max	115	99	93	92	90	86	82	87	90	93	95	129	126	110	103	91
Min	1	7	16	19	20	20	19	18	17	17	21	28	27	25	25	21
Avg	41	45	46	48	50	49	47	47	45	45	48	56	59	56	55	48

Data Source: PJM.

The steady convergence between PJM prices and ComEd prices can be seen more clearly in Figure 2. With distinct prices in February 2004, prices steadily converged over the period. The graph plots the difference between the PJM day-ahead price and the ComEd price and a simple regression line is drawn to show the trend line that demonstrates the convergence. While the prices differed by $10 or more at times, the downward slope of the line shows that there was some convergence. Usually the difference was positive, meaning the PJM price was greater that the ComEd price. A similar trend can be drawn between PJM real-time prices and ComEd prices.

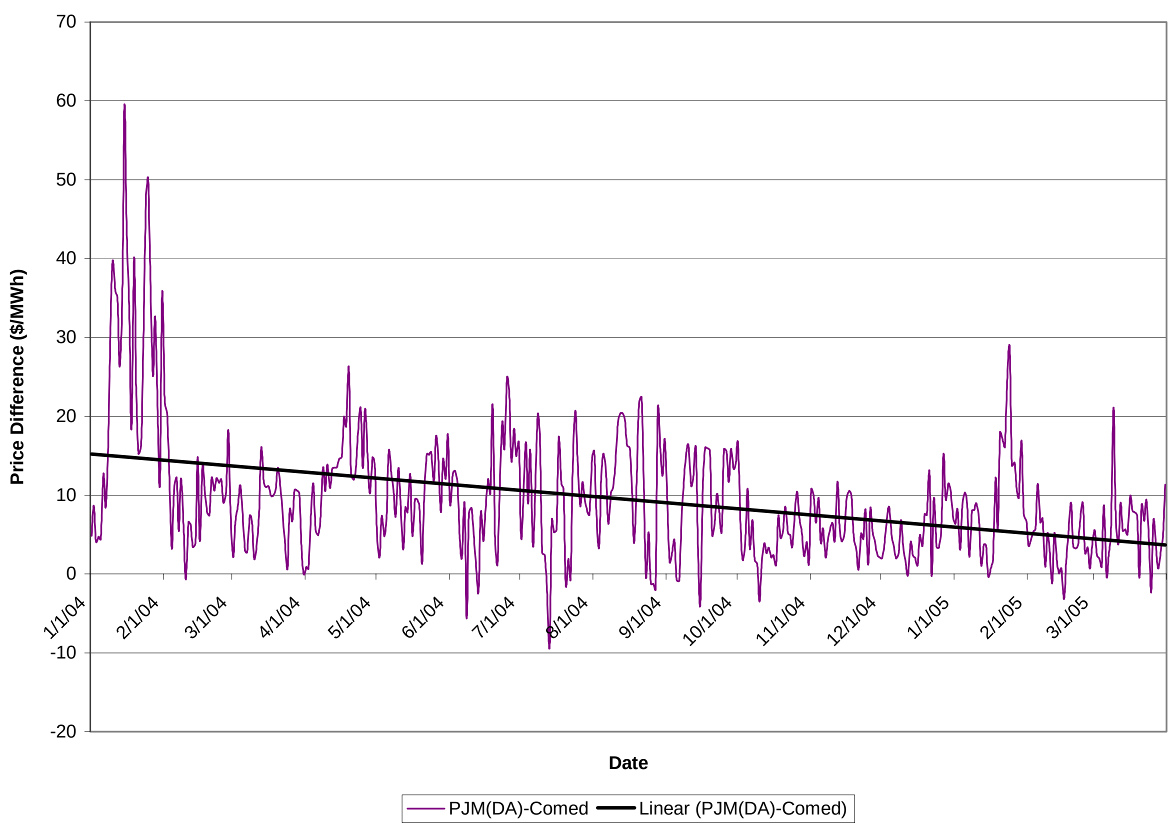


Figure 2. Difference between PJM day-ahead prices and ComEd prices.
Source: PJM for PJM day-ahead and Platts *Megawatt Daily* for ComEd.

Figure 3 shows the price duration curve for PJM, ComEd, and the AEP Dayton Hub. The price duration curve shows the range of prices in each region and what percent of the prices fell above or below a given level (the vertical axis is labeled in decimal form, so, for example, 0.1 is 10 percent and so on). The median price for PJM day-ahead was $64 versus $79 in real-time. These are both higher than AEP Dayton ($39) and ComEd ($46). The middle 50 percent of prices (25 percent of the prices below the median, and 25 percent above the median) for PJM day-ahead were between $55 to $72, while in the real-time market, they were $64 to $96. Prices for ComEd and AEP Dayton were much more stable.

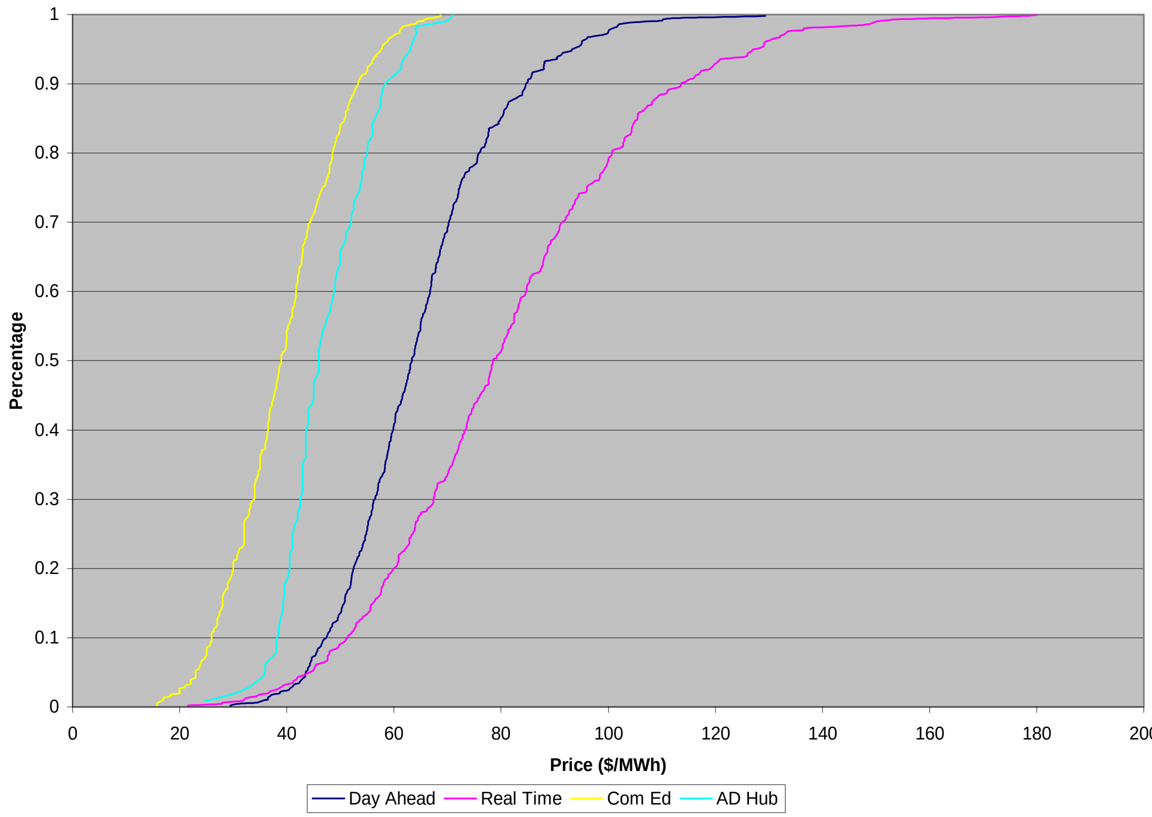


Figure 3. Price duration curve for the daily average peak hour prices for PJM regions – PJM (day-ahead and real-time), ComEd Region, and AEP Dayton Hub.
Source: PJM for PJM day-ahead and real-time, Platts *Megawatt Daily* for ComEd, and ICE for AD Hub.

Figure 4 shows the average day-ahead price for peak hours at four PJM hubs – Eastern, Western, West Int, and New Jersey. As the graph shows, prices at each of the hubs generally are correlated with one another. The New Jersey Hub tended to have the highest prices of the four hubs.

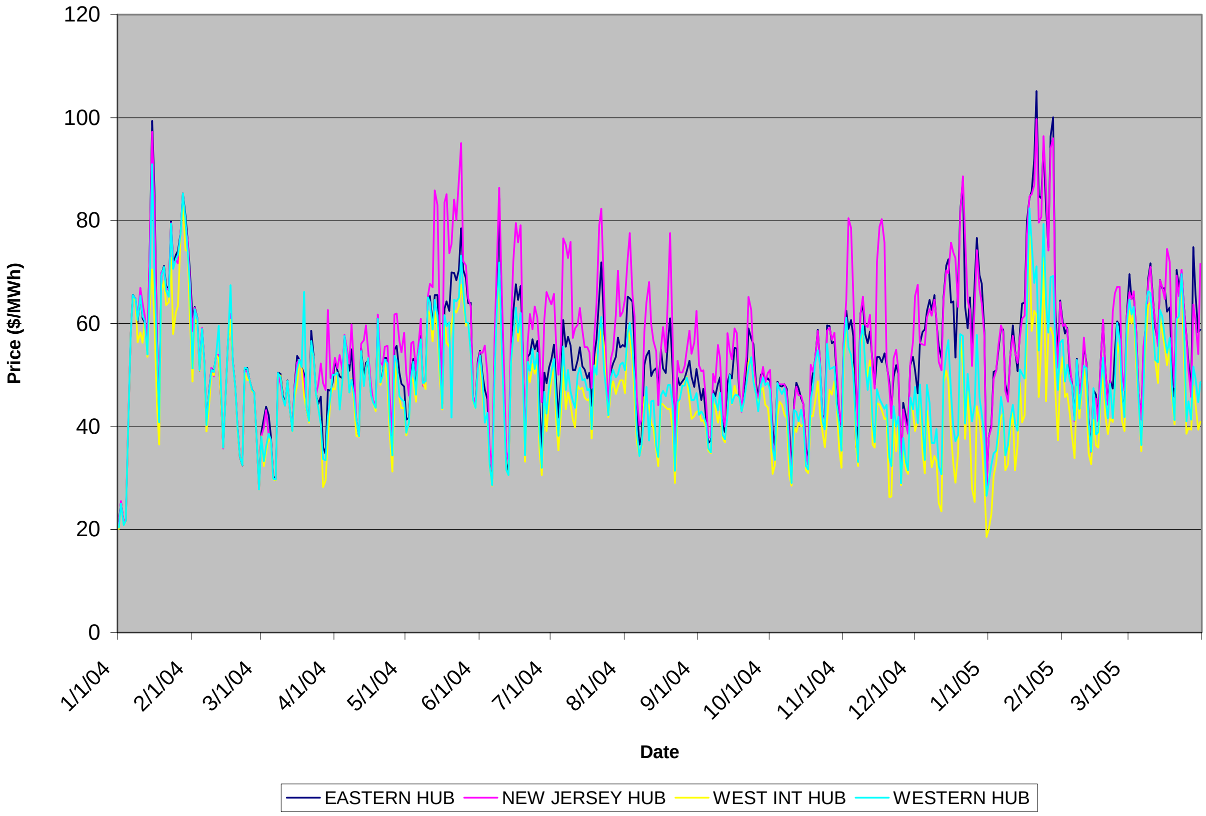


Figure 4. Daily average peak hour day-ahead prices for four PJM hubs.
Source: PJM.

Figure 5 shows the price duration curve for four hubs in PJM. The median prices ranged from $36 to $64 (for West Int and New Jersey, respectively). The middle 50 percent of prices for West Int were between $36 to $50, while the middle 50 percent of prices for New Jersey were between $48 to $64. Almost 10 percent of prices at the New Jersey Hub exceeded $75.

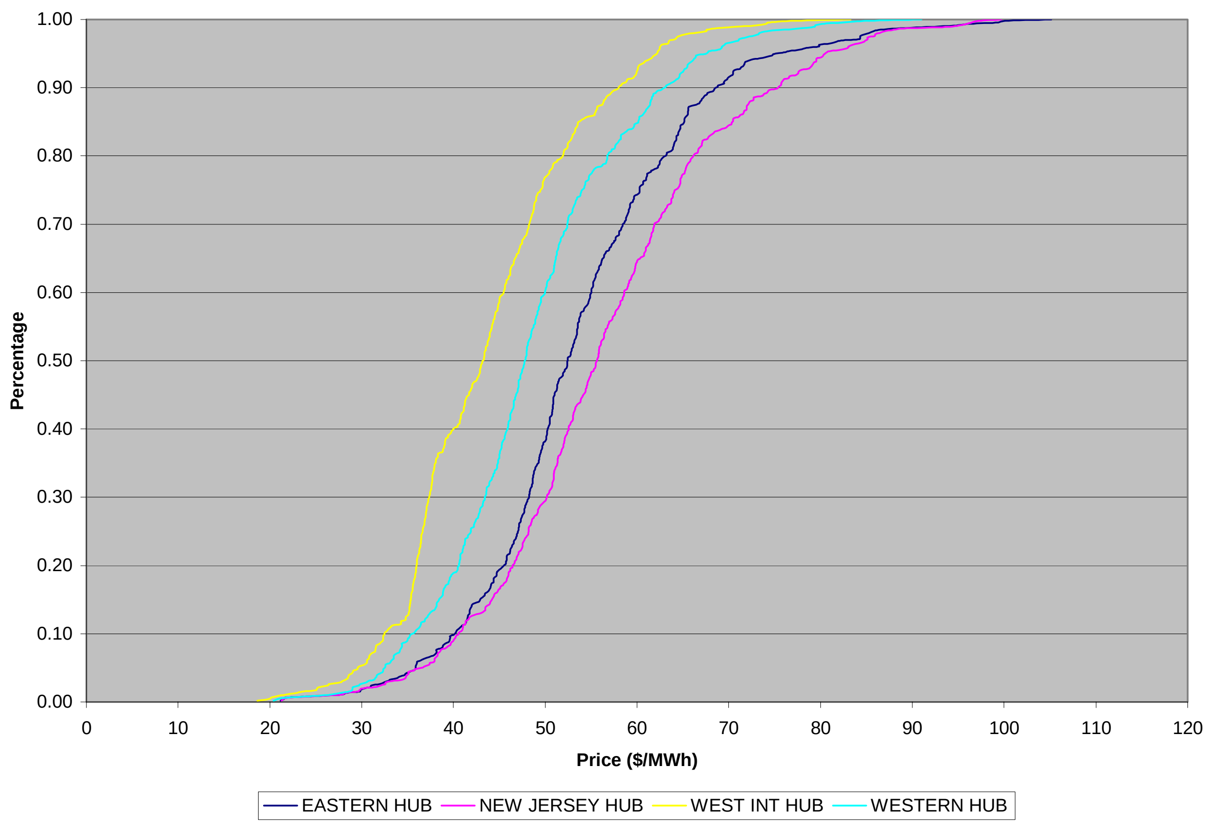


Figure 5. Daily average peak hour prices for four PJM hub day-ahead prices.
Source: PJM.

New England

Figure 6 shows the daily prices at the Massachusetts (MA) Hub relative to the monthly average load weighted prices for ISO New England (ISO-NE). The Massachusetts hub experienced a spike in January 2004[11] and January 2005 similar to the spikes experienced in New York. Excluding the month of January for both years, prices tended to be relatively stable in the $50 to $60 range.

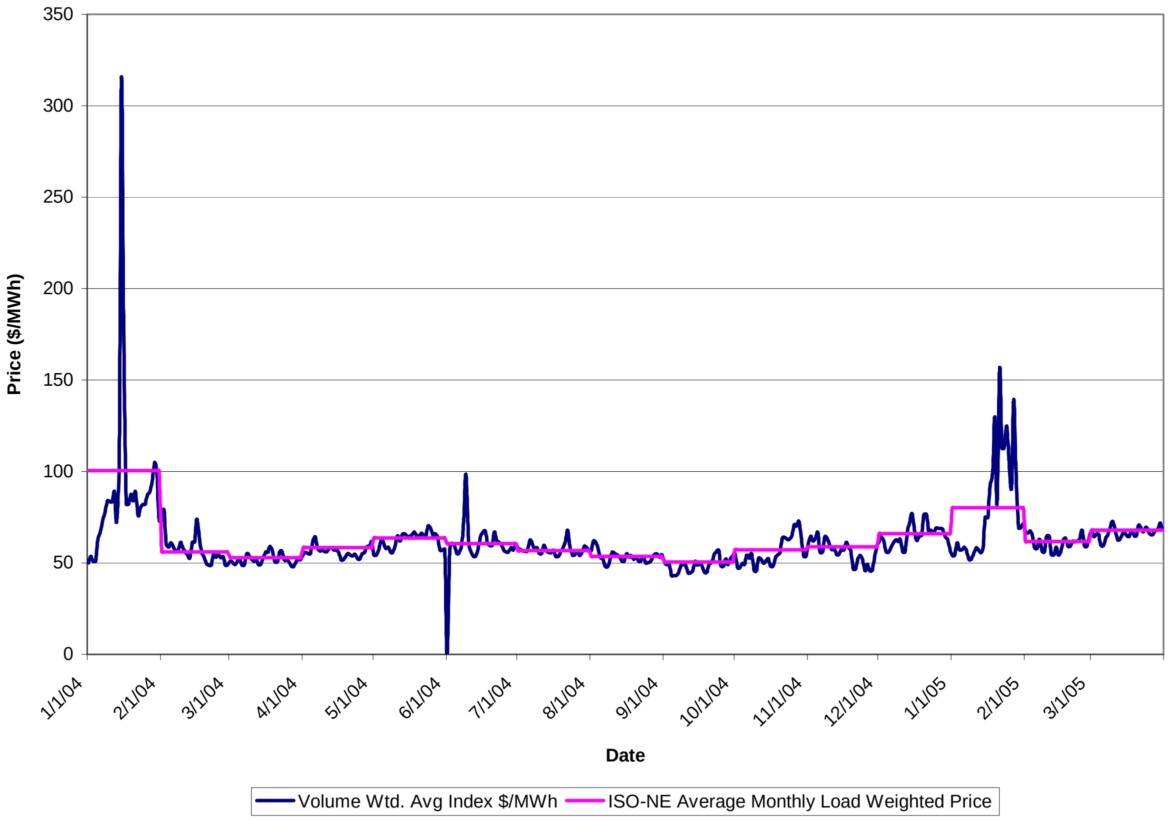


Figure 6. Daily volume weighted price for Massachusetts Hub and the monthly average load weighted price ($/MWh) for peak hours.
Souces: Platt's *Megawatt Daily* for Massachusetts Hub. ISO-NE for ISO-NE average monthly load-weighted prices.

[11]This was during the "Cold Snap" that occurred in the region January 14 through 16, 2004. This was discussed in last year's Performance Review (pp. III-4 to III-7).

Figure 7 shows the volume weighted average monthly prices at the Massachusetts Hub during peak and off peak hour. Prices in peak and off peak hours follow a similar path, though at distinctly different prices. Prices started 2004 at a peak for the entire period. The average monthly price dropped after January. For the duration of the year, price stabilized between $55 and $65 dollars. This lasted until December, where average monthly prices fell below $50, then rose to $80 in January.

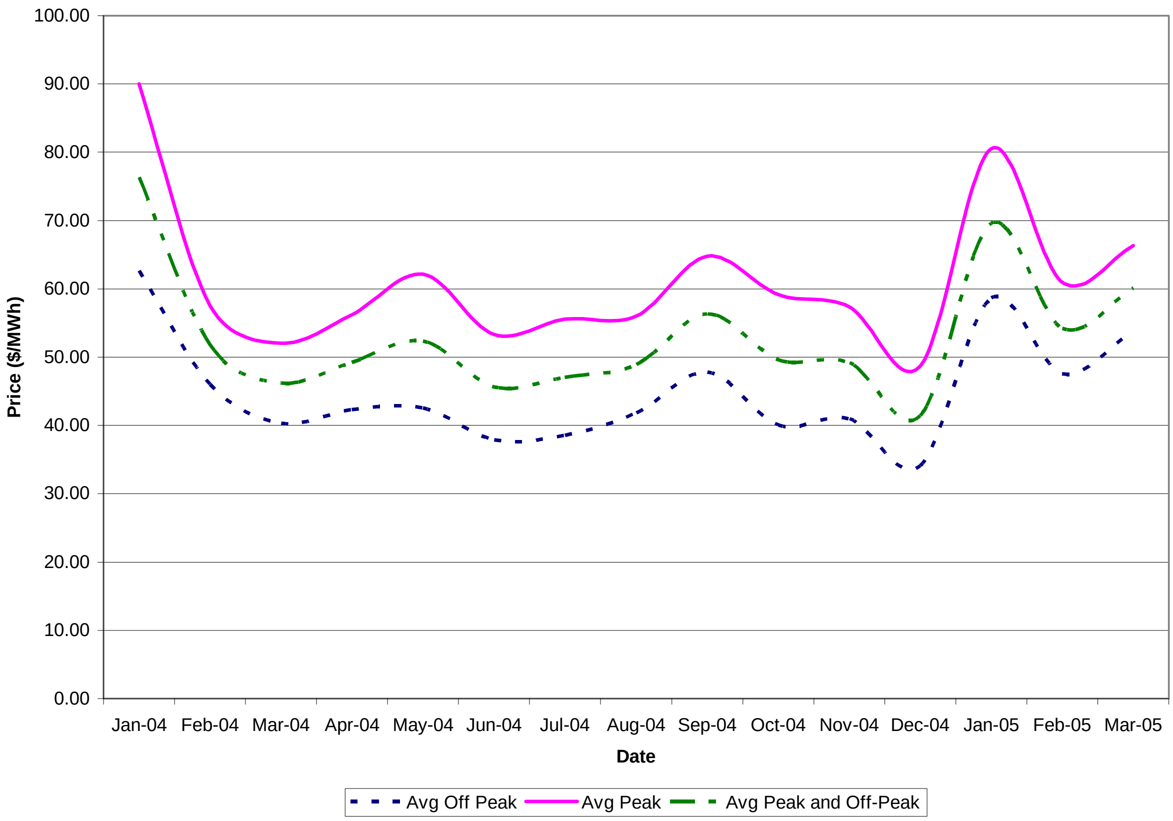


Figure 7. Monthly average volume weighted average prices ($/MWh) for peak hours, off peak hours, and average peak and off peak prices for the Massachusetts Hub. Souces: Platt's *Megawatt Daily*.

The price duration curve for the Massachusetts Hub in Figure 8 shows that prices remained in the $55 to $65 range much of the time. For the time period shown, 50 percent of prices fell between $53 and $65. The Massachusetts Hub showed more dispersion at the high end of prices than the low end. For example, only once did the price fall below $40 ($0 on June 6, 2004). Excluding that day, the range of the lowest 10 percent of prices was $43 to $49, while the highest 10 ranged from $73 to $177 (excluding the $315 that occurred on January 1, 2004). Overall, prices remained fairly stable for the period examined.

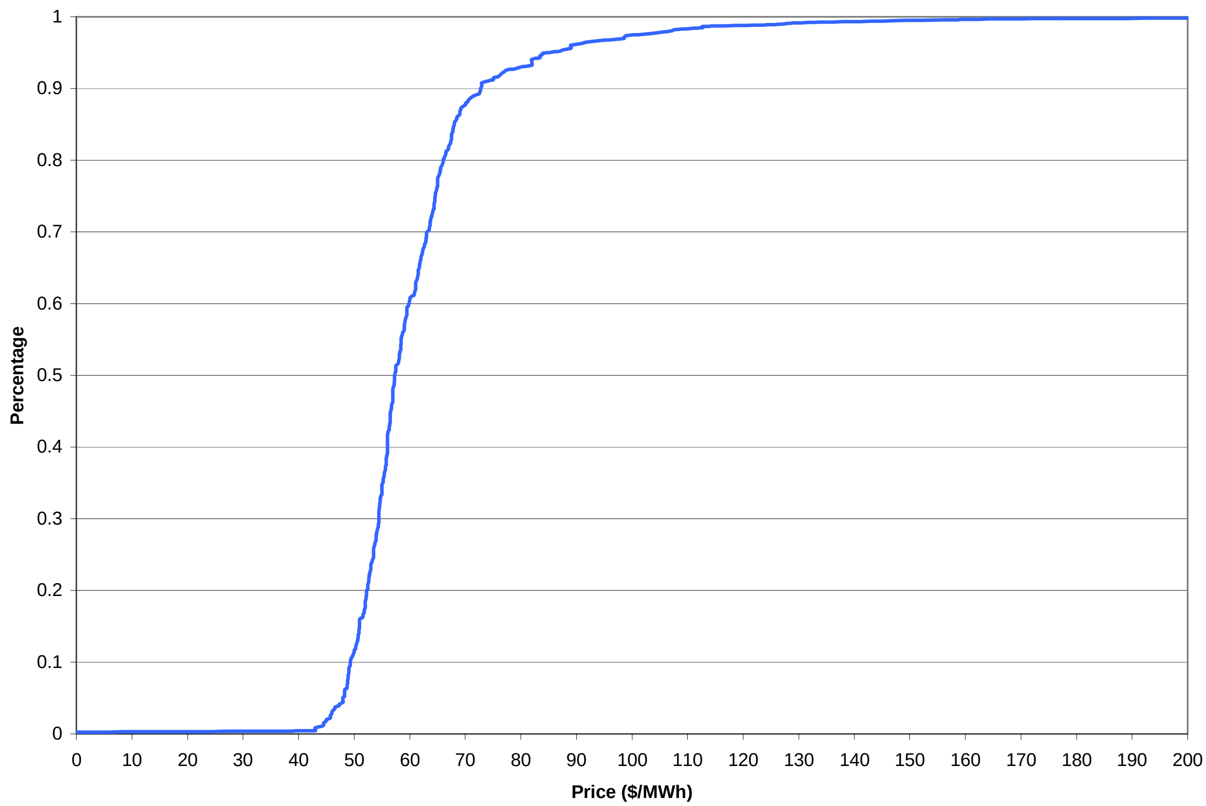


Figure 8. Price duration curve for Massachusetts Hub.
Source: Platts *Megawatt Daily*.

New York

Three New York ISO zones, Zones A, G, and J, are used for comparative purposes. Zone A is the western most region of New York and includes Buffalo and points south and west. Zone G is the Hudson Valley region just to the north of New York City. Finally Zone J is the New York City area. These three regions represent three levels of load and congestion.

Figure 9 shows the daily prices in Zones A, G, and J relative to one another as well as to the monthly average prices. As the graph shows, spikes in any one zone are generally accompanied by a corresponding spike in the other zones. These spikes differ in magnitude based on zone. Prices tended higher in January 2004 for all regions. January 2005, though lower in price than January 2004, also shows increased volatility relative to December and February.

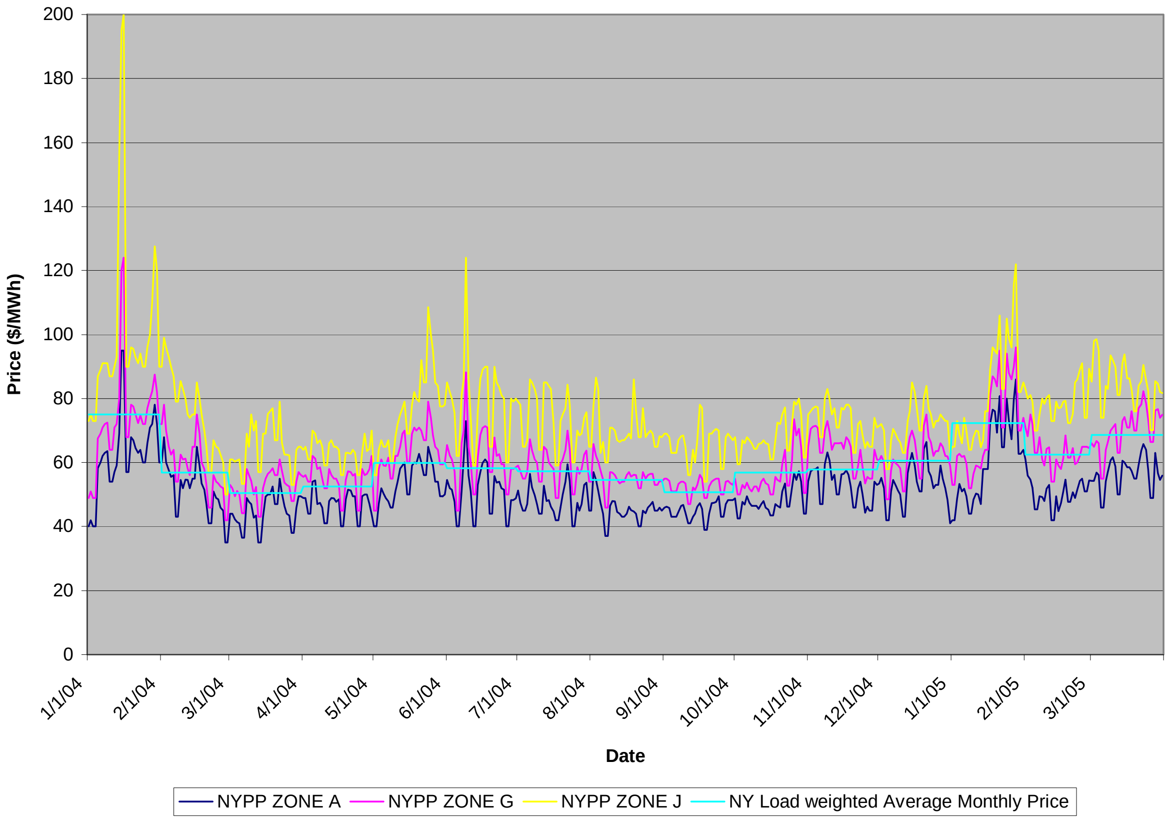


Figure 9. Daily volume weighted price for NYPP Zones A, G, and J and monthly average load weighted prices ($/MWh) for peak hours.
Souces: Platt's *Megawatt Daily* for Zones A, G, and J and NYISO for New York load weighted average monthly prices.

Figure 10 shows the average volume weighted average prices ($/MWh) for Zones A, G, and J. Prices in all three zones follow a similar price path, however they do so at very different price levels. These prices show trends of normal seasonal load in northern regions. That is, as demand fell in the spring and fall months, so did prices. However, prices rose gradually through the later fall and winter months. This increase is likely due to the increased need for natural gas during the heating season, which causes the price of natural gas to increase for electricity generation as well. It should be noted the Zone J (New York City area) had the highest average price for every month, while Zone A (western most zone in the state) had the lowest price in every month. Also, prices in Zone G (the Hudson Valley region) closely followed the prices for the day-ahead and real-time load weighted price for the entire state of New York.

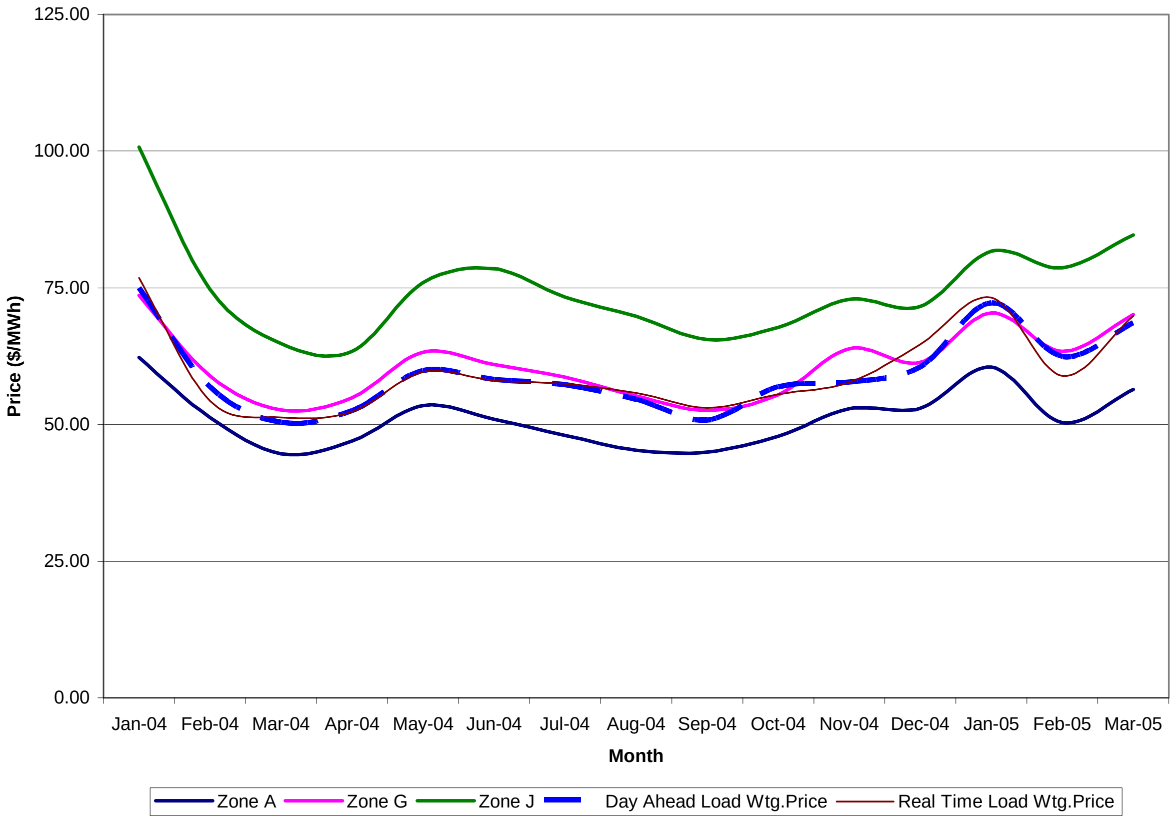


Figure 10. Monthly average volume weighted average prices ($/MWh) for peak hours. Souces: Platt's *Megawatt Daily* for Zones A, G, and J and NYISO for day-ahead and real-time prices.

Figure 11 represents the price duration curve for all volume weighted average prices for the three zones. Again, the price duration curve shows the range of prices in each region and what percent of the prices fell above or below a given level. The median price for Zone A is approximately $50, therefore; 50 percent of the prices in Zone A during peak hours fell below $50 for the time between January 1, 2004 and March 31, 2005. The median prices for Zones G and J were $60 and $73, respectively. The range of prices show that prices were reasonably stable. For Zone A, the middle 50 percent of prices (again, defined as 25 percent of the prices below the median, and 25 percent above the median) fell between $45 and $55. Zone G had a similar range, from $54 to $66, while Zone J had a range of $65 to $82. Finally, prices exceeded $100 for about 3 percent of the time in Zone J and less than 1 percent in Zone G.

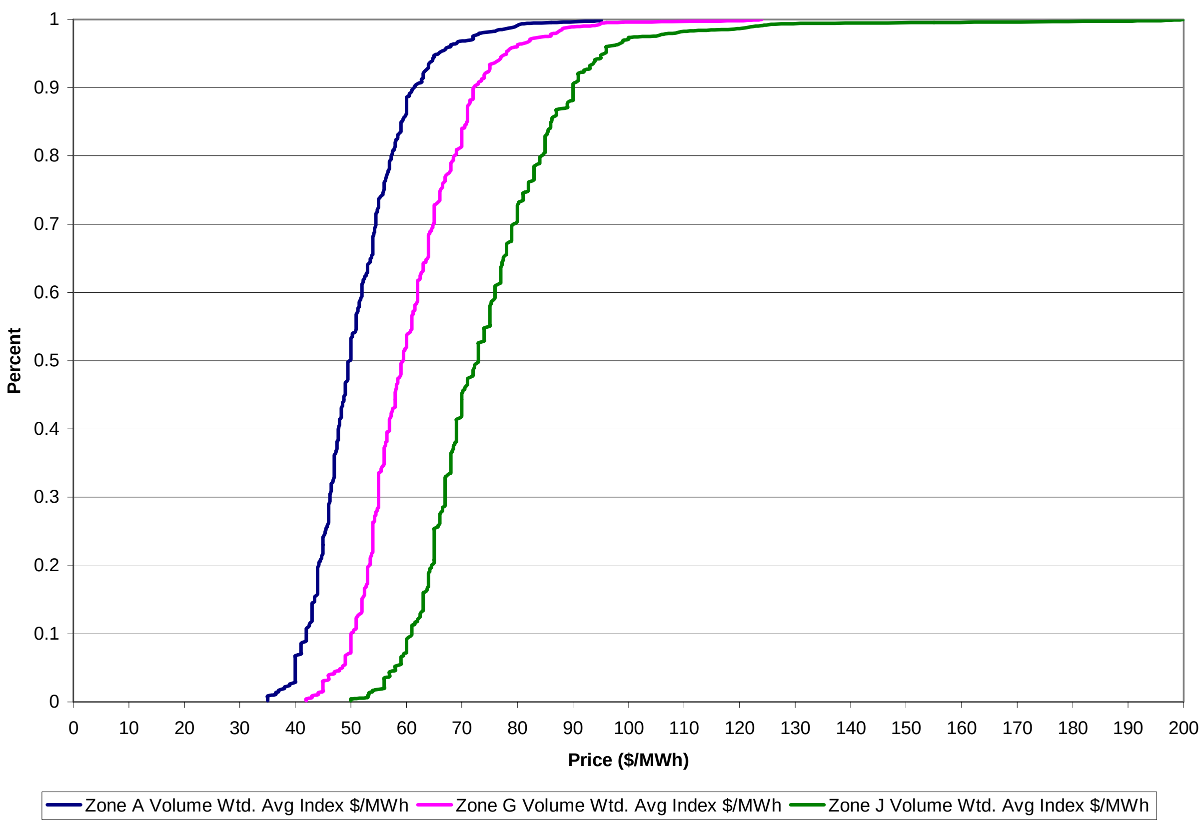


Figure 11. Price duration curves for NYISO Zones A, G, and J.
Source: Platts *Megawatt Daily*.

Midwest

Figure 12 shows the volume weighted price indices for Cinergy. With ComEd joining PJM, Cinergy is one of the major trading zones in the Midwest. Prices generally ranged between \$30 and \$60 for the time period examined. However, prices are showing slow increases over time, that likely reflect fuel price increases.

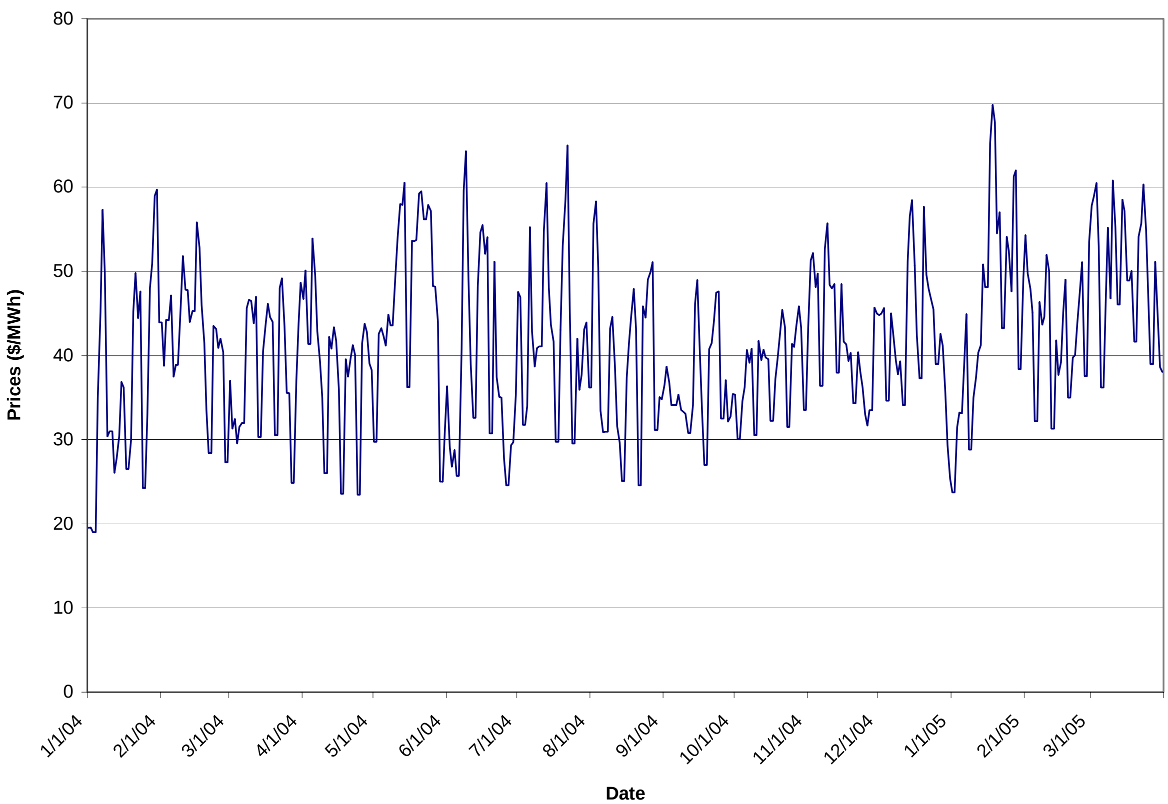


Figure 12. Daily volume weighted price indices (\$/MWh) for Cinergy.
Source: Platts *Megawatt Daily*.

Figure 13 shows the volume weighted prices for five Midwest hubs. Price movements seem to be fairly correlated across hubs. Prices at these hubs usually ranged from \$30 to \$60, similar to Cinergy, however, prices tended to fall below \$30 more than Cinergy. An overall trend of increasing prices, similar to Cinergy can also be observed.

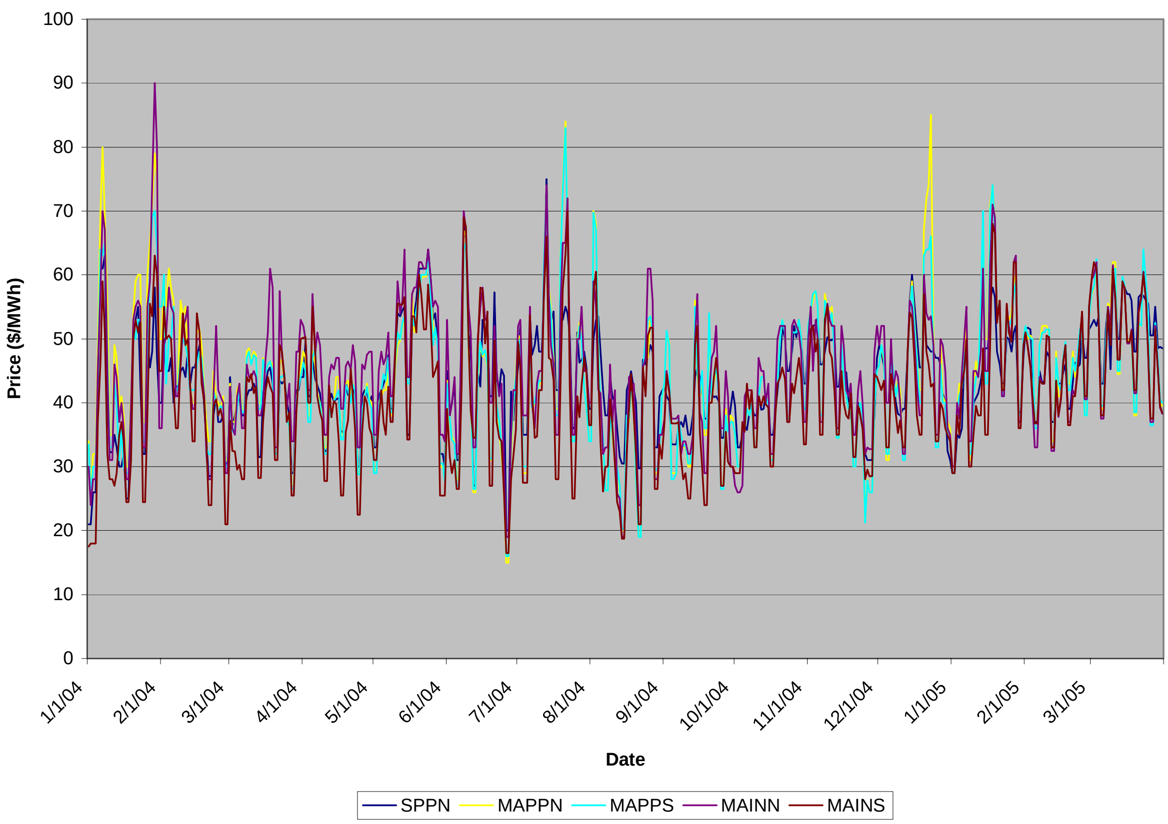


Figure 13. Volume weighted daily price indices (\$/MWh) for five Midwest trading hubs. Source: Platts *Megawatt Daily*.

Figure 14 shows the monthly average prices for five Midwest hubs. Here the increase pricing trend is slightly more apparent. Prices fluctuated through August of 2004, and then began a steady increase that has covered the duration of the time period. Even though prices continue to rise, they are still in a similar price range (here, $40 to $50 monthly average) as they were at the start of the period.

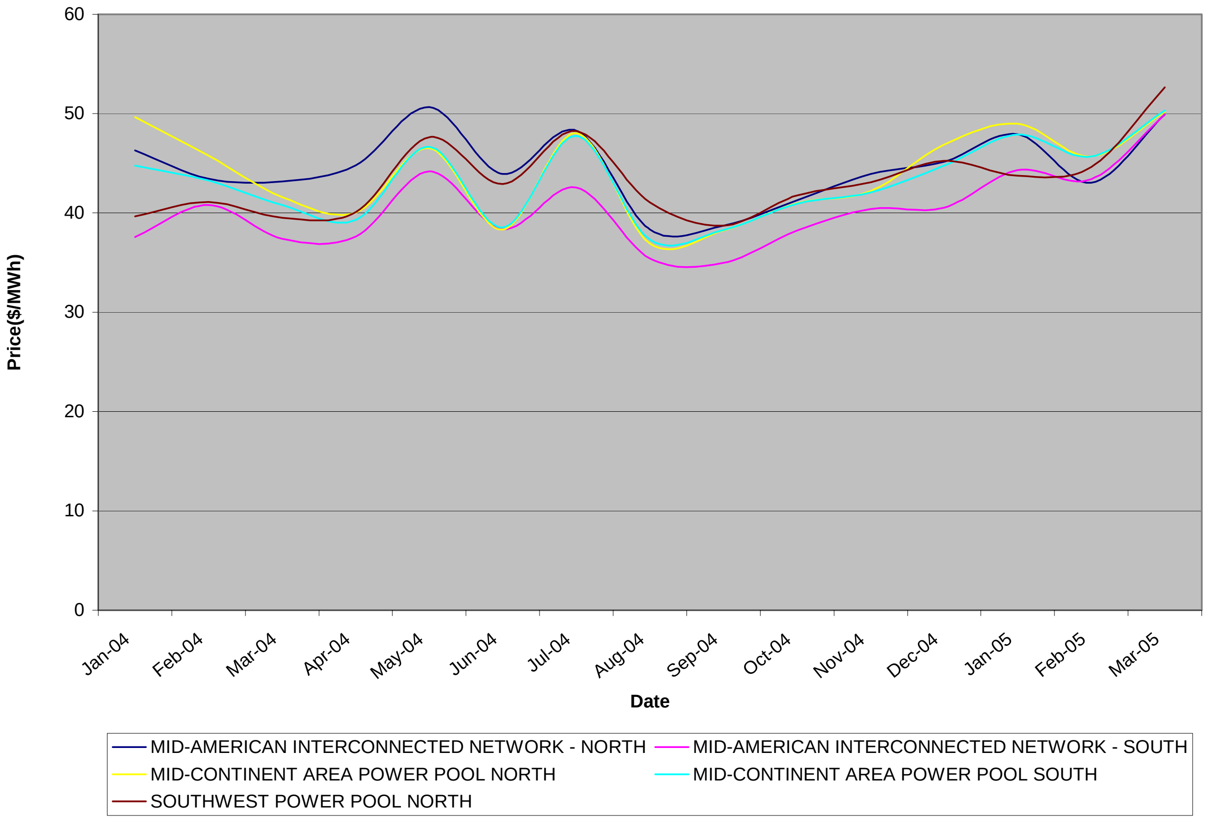


Figure 14. Monthly average daily volume weighted price indices ($/MWh) for five Midwest trading hubs.
Source: Platts *Megawatt Daily*.

South and Southeast

Figure 15 shows the volume weighted prices for four Southeast trading hubs. In Entergy, Southern and TVA, prices tended to range from $30 to $60, while Florida saw prices ranging from $40 to $70. Florida showed the highest prices on almost every day. Prices tended to be correlated across hubs.

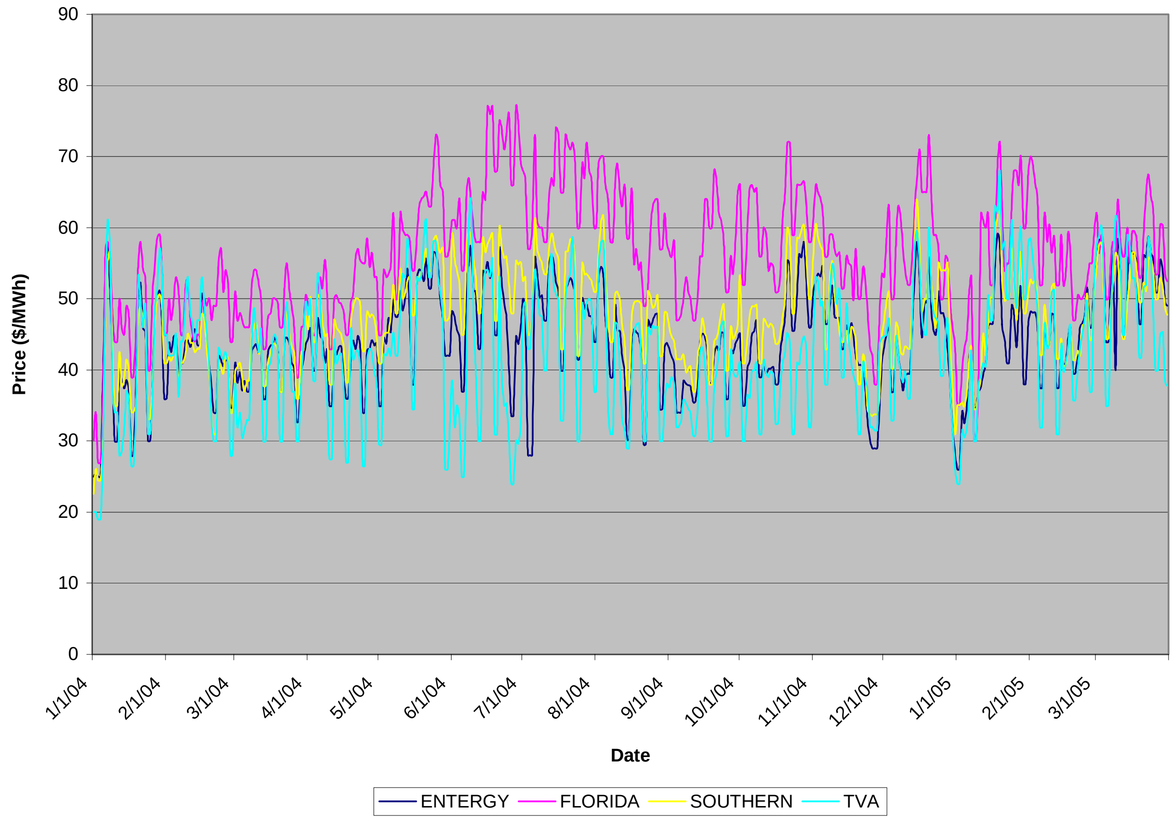


Figure 15. Daily volume weighted price indices ($/MWh) for Southeast trading hubs. Source: Platts *Megawatt Daily*.

Texas

Figure 16 shows the daily volume weighted prices for the five zones in ERCOT. ERCOT serves about 85 percent of the Texas state electric load and is electrically isolated from other U.S. regions. Nearly all of the electricity consumed in ERCOT is also generated there. Between January 2004 and March 2005, prices tended to stay in the $40 to $60 range for all five regions. Due to the fact that ERCOT is isolated, prices in all the zones tend to move in conjunction with one another. In late October, there was a price spike where most of ERCOT saw prices soar from the low $40s to over $100.

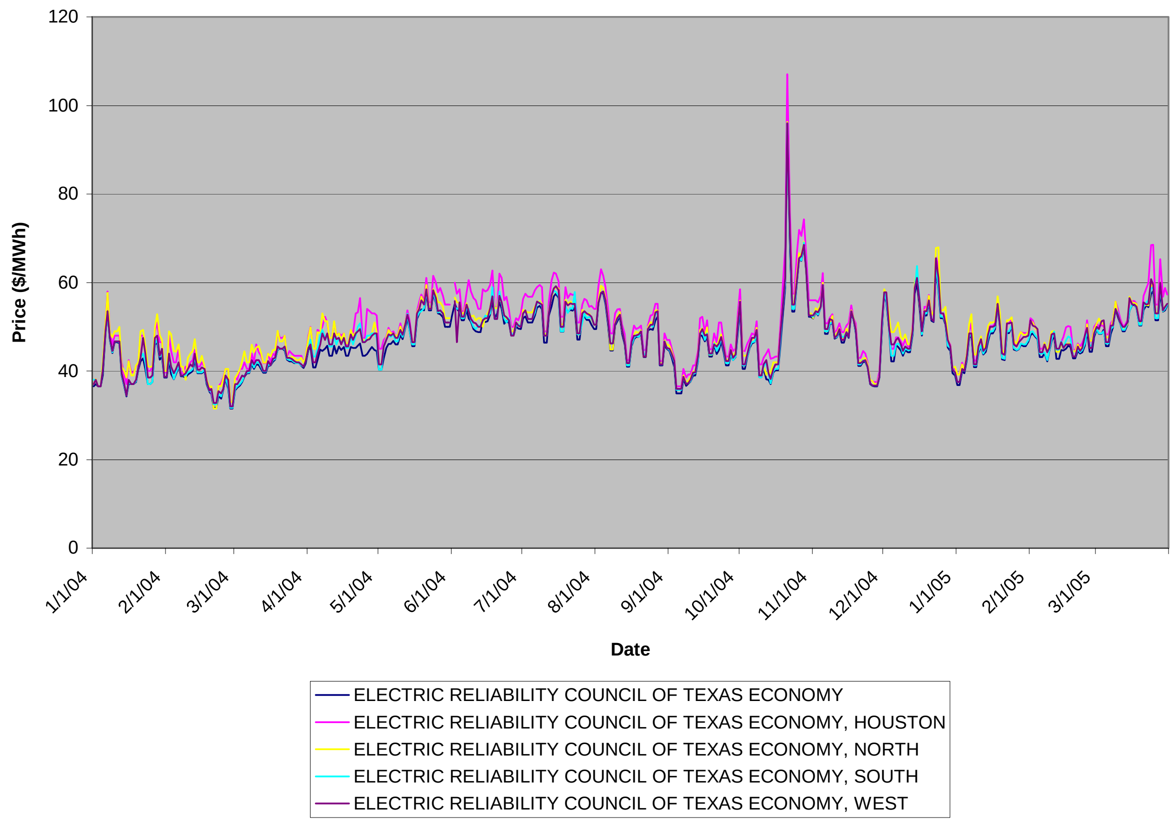


Figure 16. Daily volume weighted price indices ($/MWh) for ERCOT trading zones. Source: Platts *Megawatt Daily*.

Figure 17 shows the price duration curve for the five zones in ERCOT. As can be seen in the graph, median prices had a very small range. The region as a whole had the lowest median price at $46, while the Houston zone had the highest at $49. With exception of Houston, all zones had 90 percent of their prices fall at or below $55. Houston had 25 percent of the prices fall above $55. Rarely did the price fall below $39. The middle 50 percent of prices fell between $42 and $54.

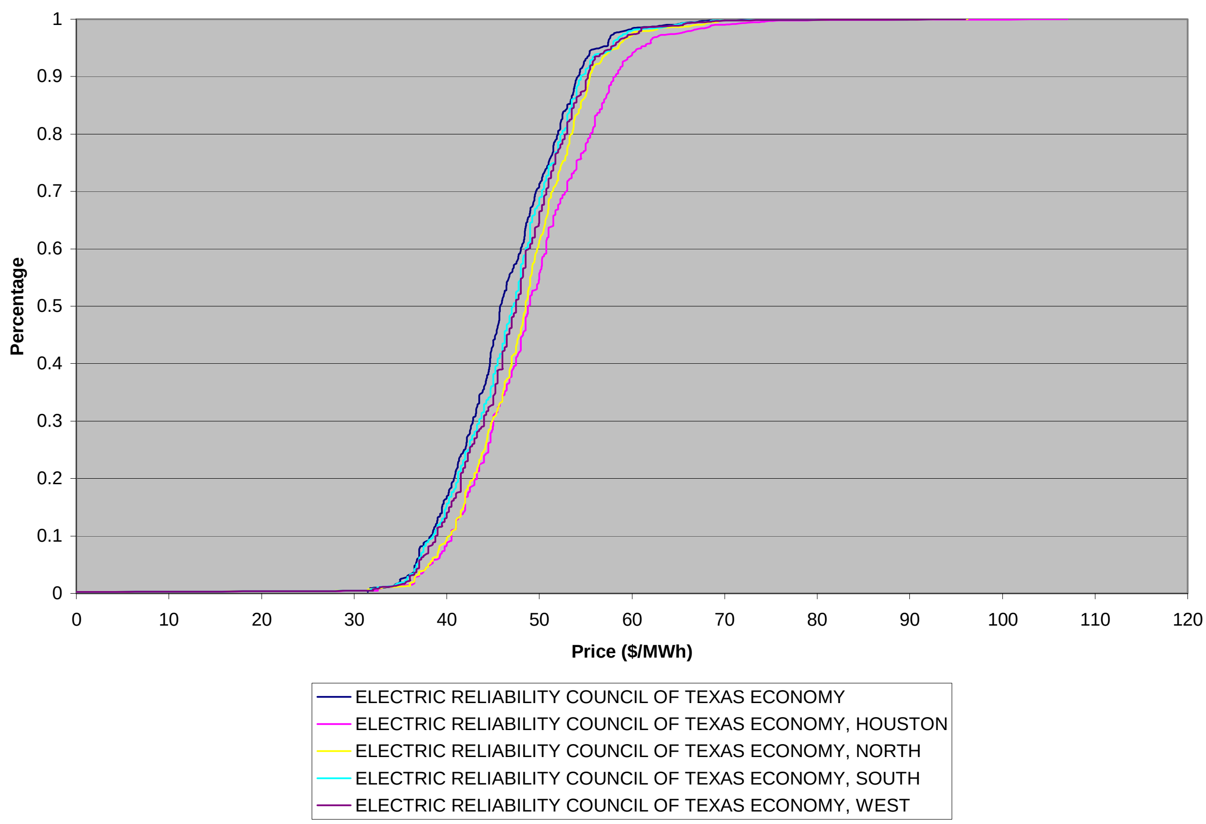


Figure 17. Price duration curve for daily volume weighted price indices ($/MWh) for ERCOT Trading Zones.
Source: Platts *Megawatt Daily*.

West

Figure 18 shows the volume weighted price indices ($/MWh) for the Western region. With the exception of Mead Nevada, most of the prices tend to move in the same direction. In June of 2004, all regions except Mead experienced a steady but dramatic drop in prices from the mid $50s to as low as $10 in Mid-Columbia (mostly hydro-power). However, prices rebounded by mid-June to the price level prior to the dip.

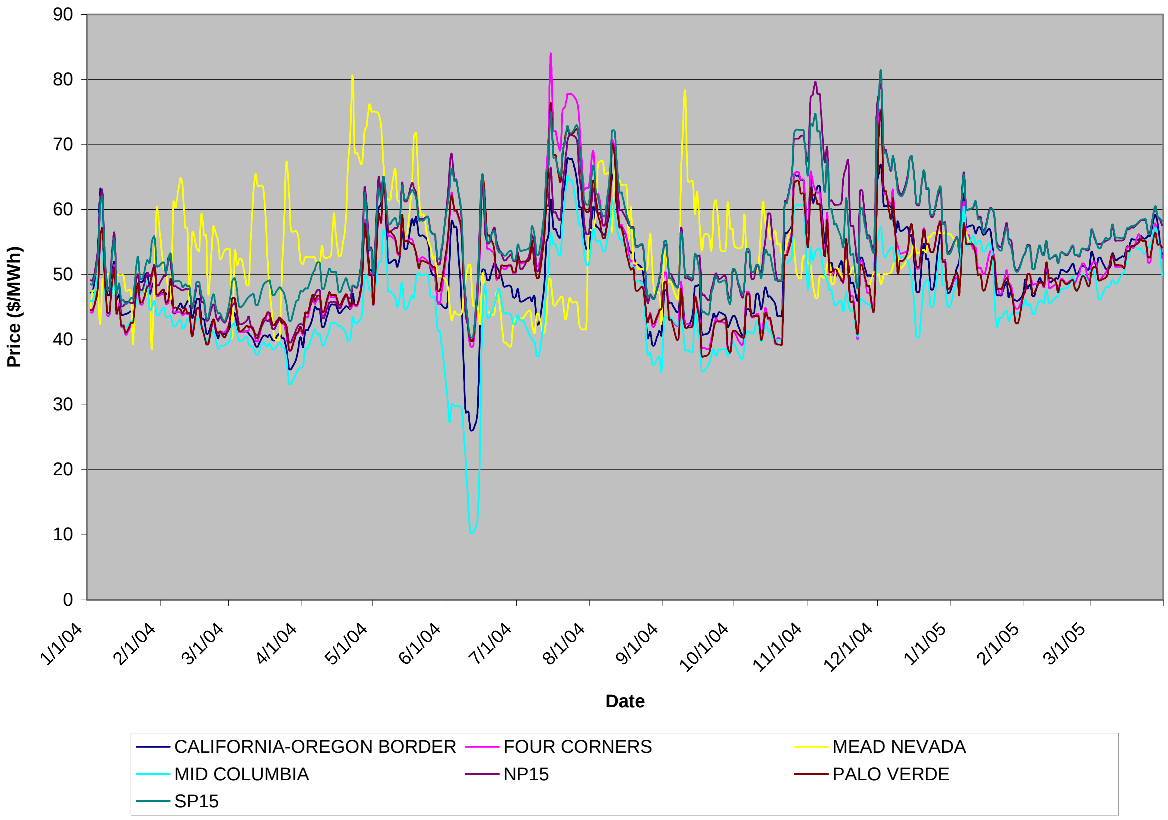


Figure 18. Daily volume weighted price indices ($/MWh) for the Western region. Source: Platts *Megawatt Daily*.

Figure 19 shows the price duration curve for the Western region. Price variation is similar for all regions. Mid-Columbia (again, mostly hydro-power) tends to show the lowest prices in the region, with a median price of $45 versus a median price of $54 for NP15 (which had the highest median price). For all regions, the middle 50 percent of all prices are in a $10 to $12 range above or below the median or a total range of $20 to $24.

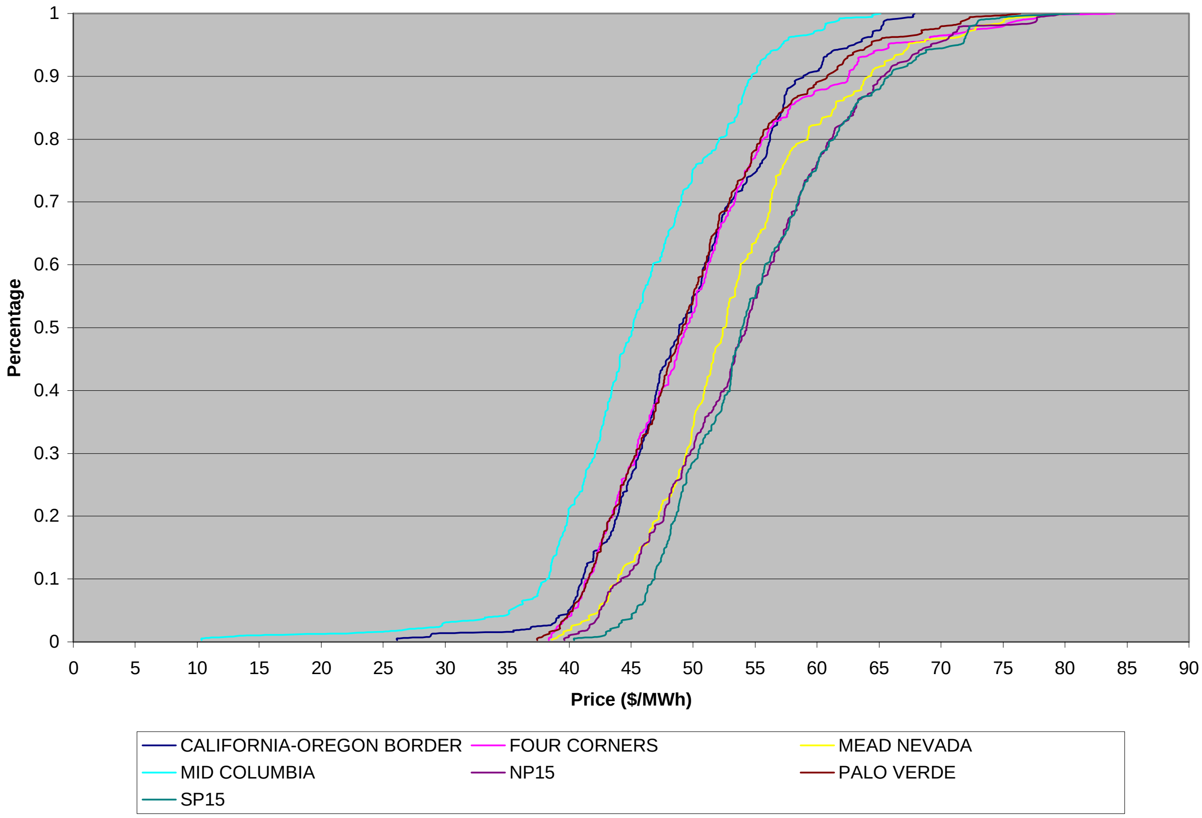


Figure 19. Daily volume weighted price indices ($/MWh) for the Western region. Source: Platts *Megawatt Daily*.

Retail Markets

Overview

At one point in the late 1990s, restructuring legislation had passed or was in various legislative stages of informal discussions, hearings, proposed legislation, or other activities in nearly every state. As summarized in Figure 20, currently, most states have decided to either postpone these efforts to implement retail access or have stopped considering adopting it altogether. Sixteen states and the District of Columbia have fully implemented their legislation and commission orders and currently allow full retail access for all customer groups. Two states allow retail access for larger

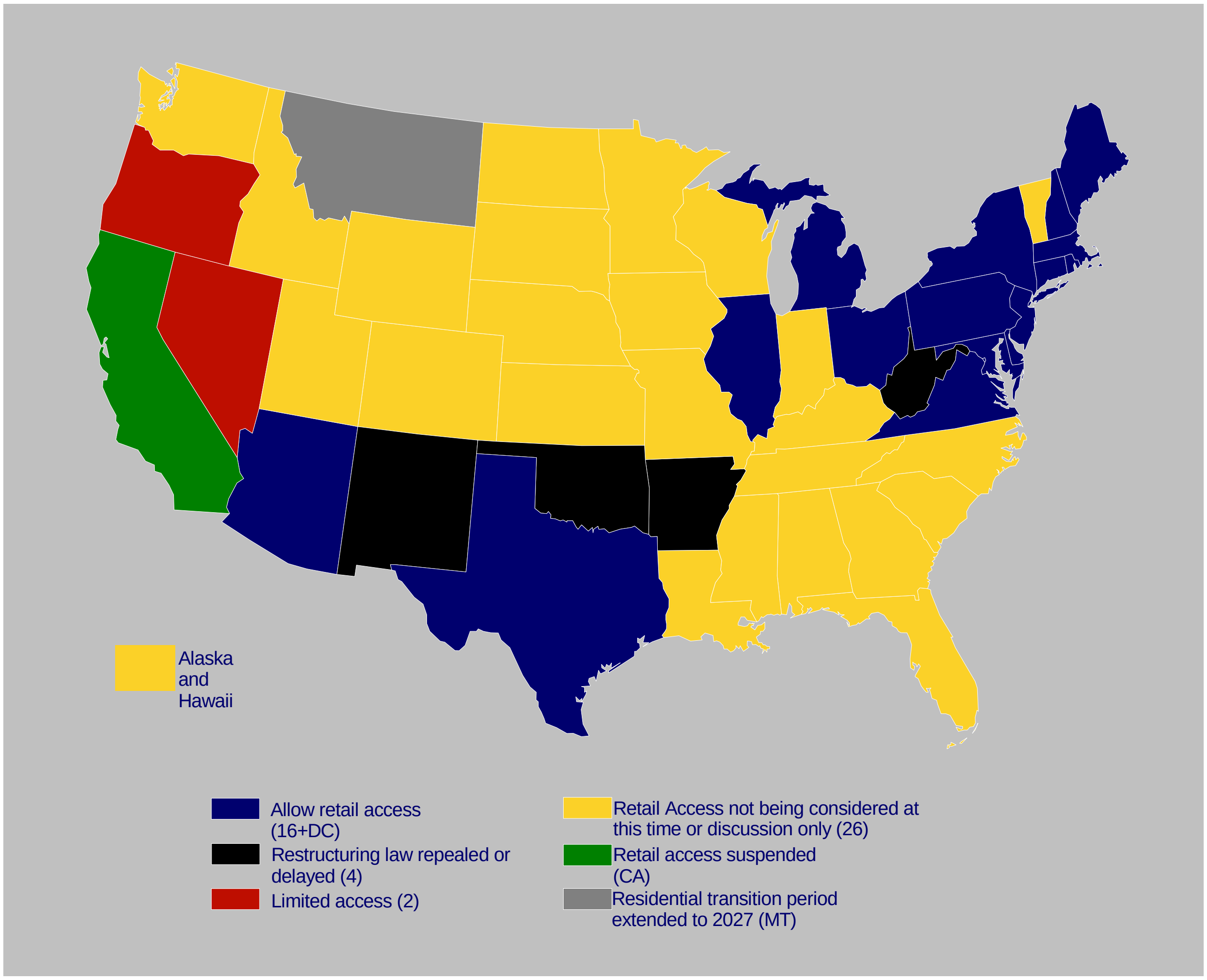


Figure 20. Status of state retail access.

customers only; Nevada, which modified its original law to limit access to just larger customers, and Oregon, whose original law limited retail access to larger customers. Six states that passed restructuring legislation later delayed, repealed, or indefinitely postponed implementation. Oklahoma and West Virginia passed restructuring legislation but stopped short of implementation; Arkansas and New Mexico have repealed their laws; California suspended the retail access program it already had implemented in September 2001, more than one year after the beginning of the California and western power crisis. Montana has also been dealing with the severe aftermath of the western power crisis and extended the transition period to retail access for smaller customers. Montana implemented retail access for large industrial customers in July 1998, but residential access originally scheduled to begin by July 2002, was postponed to 2027.

Twenty-six states are no longer considering restructuring at this time. None of these states appear to be working in any meaningful way toward passage at this time. No state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning to take shape. These states that did not pass legislation, but were in the process of considering it, either gradually lessened their efforts to allow time to consider what was occurring in the West, or they abruptly stopped any activity that was ongoing at the time. Thus, a total of 34 states have repealed, delayed, suspended, limited retail access to just large customers, or are now no longer considering retail access.

The single biggest factor stopping this activity was the price run-ups in California and the West beginning in mid-2000 until mid-2001. Also, following the western power crisis, the electric supply industry was beset by a series of other widely reported problems, including the Enron disclosures and collapse in late 2001, revelations of market price manipulation strategies, disclosures of accounting improprieties and data misreporting, the continuing "credit crunch," and the August 2003 blackout, the most extensive blackout in North American history. This is not to contend that all these events were directly due to electric restructuring, rather that these events caused sufficient concern among policy makers to cause them to rethink restructuring.

Retail Market Activity

Figure 21 shows the percentage of residential load that is supplied by an alternative supplier for 2004 and 2005. Only two states have percent of residential load “switching” greater than 10 percent in 2005. One state is Ohio where most of the residential switching in the state has been through the state's aggregation program. The other is Texas that is now the most active state in the country in terms of residential customers choosing a supplier. The reason for this will be discussed in the individual state summaries later in this section of this report. Most states are well below five percent. Nine states are at or near zero percent.

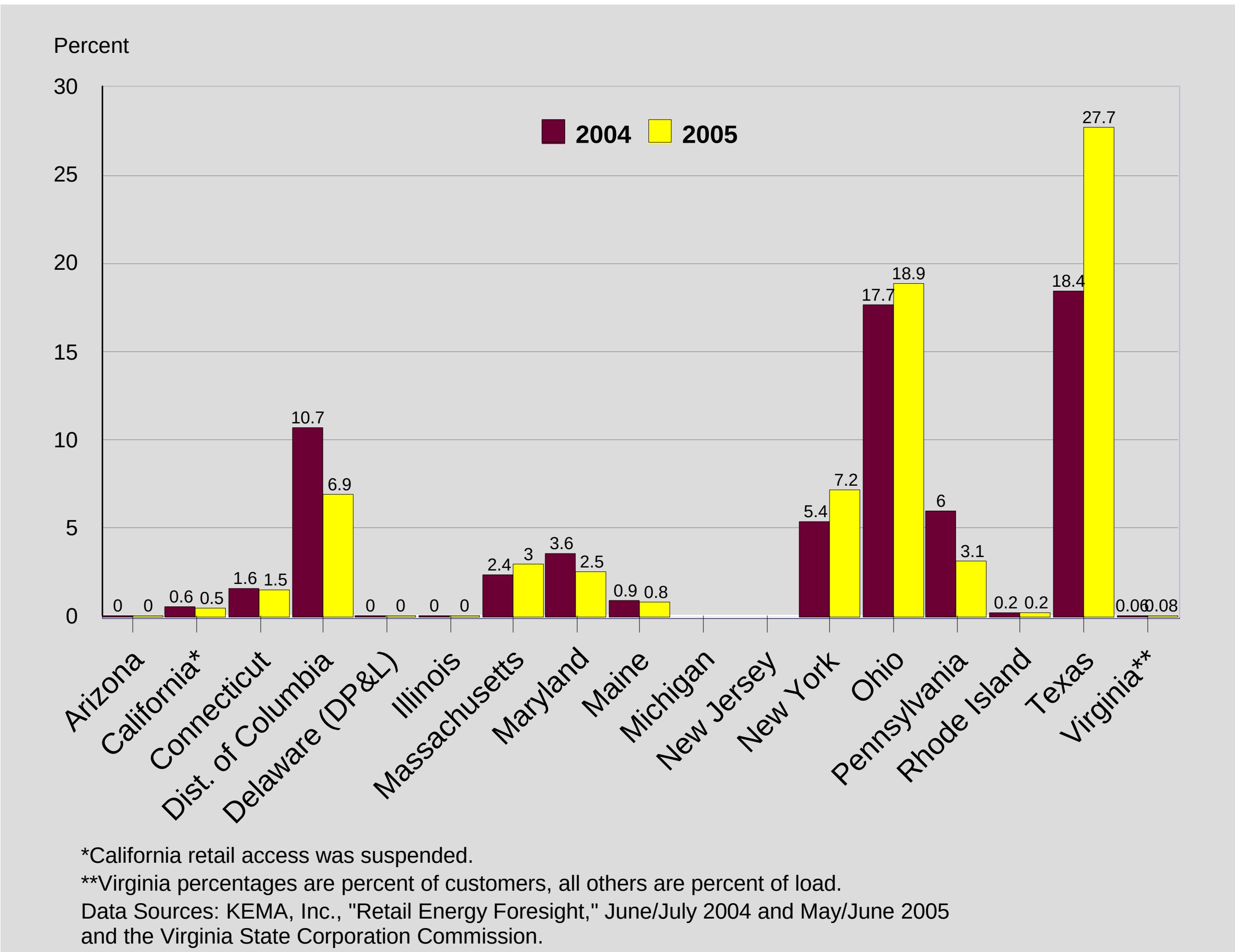


Figure 21. Percent of residential load served by competitive suppliers.

Figure 22 shows the percent of commercial and industrial load served by competitive suppliers in early 2005, which was considerably higher than for residential load. Six states, D.C., Illinois, Massachusetts, Maine, New York, and Texas, had a larger customer group (either commercial, industrial, or combined commercial and industrial) with greater than 50 percent of load served by competitive suppliers. Two were above 80 percent. Four states had no larger customer category above ten percent.

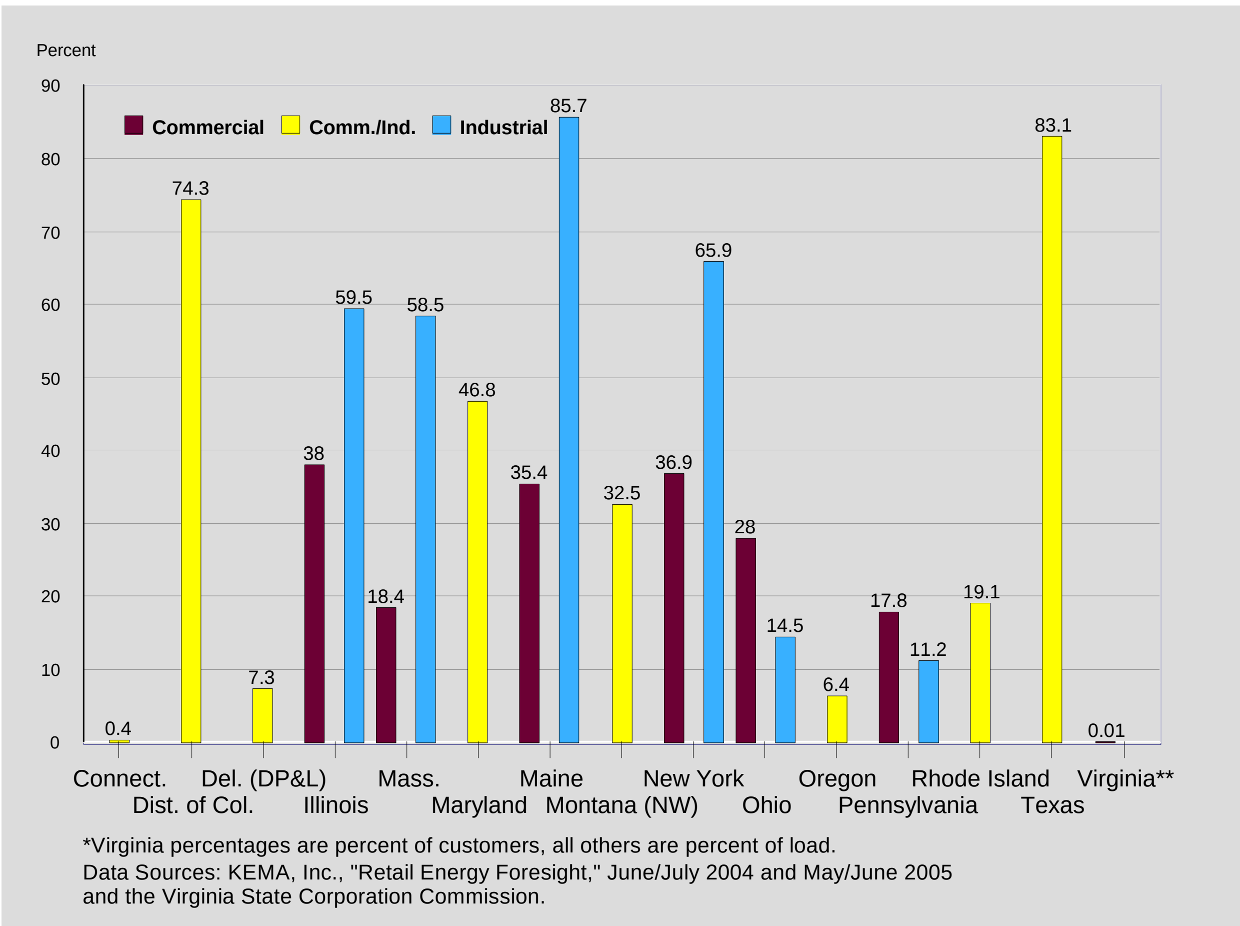


Figure 22. Percent of commercial and industrial load served by competitive suppliers.

Figure 23 shows the percent of total state load served by competitive suppliers for 2004 and 2005. Five state had greater than 30 percent of the total state load being served by competitive suppliers, D.C., Illinois, Maine, New York, and Texas. However, six states had less than ten percent of the total state load being served by competitive suppliers.

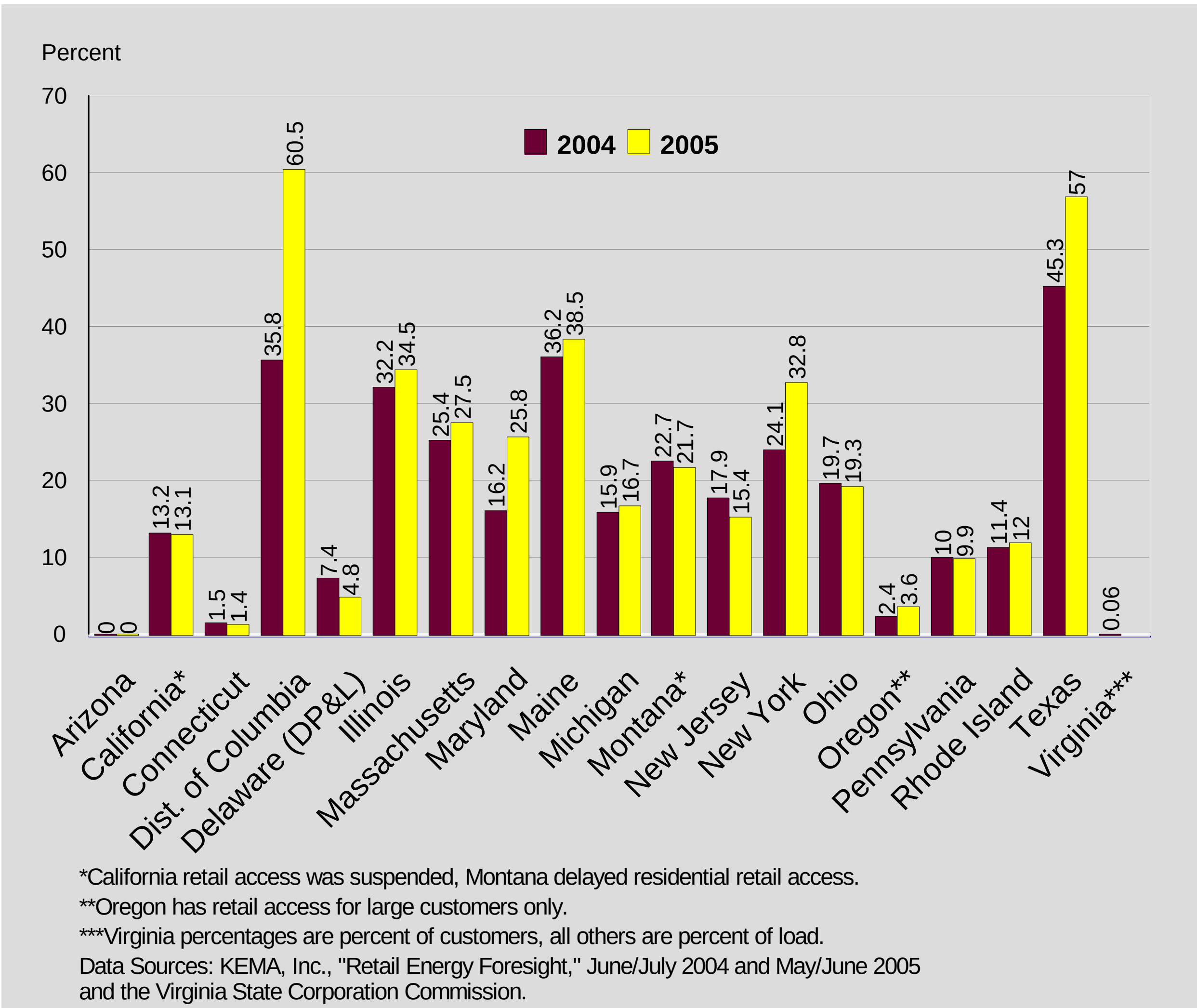


Figure 23. Percent of total state load served by competitive suppliers.

State Updates

The following are brief updates of several states that have had significant developments since last year's Performance Review. Following these summaries is a table (Table 3) that briefly covers 19 states and D.C., including all the states with full retail access for all customers groups.

New Jersey

The New Jersey Basic Generation Service (BGS) auction is an Internet-based, simultaneous multi-round descending clock auction. The auction determines the generation portion for customers that have not selected a supplier. A summary of how the auction works and past auction results are in last year's Performance Review. The results of the "fixed-price" BGS auctions (for smaller commercial and residential customers) are shown in Table 2. Comparing the first 12-month fixed-price BGS auction results in 2002 to the third 12-month auction in 2004, prices increased modestly for three of the four New Jersey companies involved, from about seven percent to just over nine percent, and decreased even more modestly, just over four percent, for the fourth company. Comparing the 34 month auction in 2003 with the 36 month auction in 2004, prices decreased slightly, from less than one percent for three of the companies to almost two percent for the remaining company. However, prices in the 2005 auction increased significantly above the 2004 auction. Comparing the 36 month auction in 2004 to the 36 month auction in 2005, prices increased over 18 percent for Public Service Electric & Gas, about 20 percent for Jersey Central Power & Light and Atlantic City Electric, and just over 28 percent for Rockland Electric. Nearly all the residential customers in the state receive basic generation service (see Figure 21).

It is important to note that auction price percentage increases do not directly translate to the same percentage changes in retail prices. This is because the auction is for determining only the generation component of the total retail price (which also includes distribution and other customer charges) and because of the mix of different contract lengths that remain in effect.

Table 2. Price results from the Fixed Price auctions for small and medium-sized customers in New Jersey, 2002 to 2005 (cents/kWh).

	2002 Auction	2003 Auction		2004 Auction		2005 Auction	Percent Increase 2004 to 2005
	12 month	10 month	34 month	12 month	36 month	36 month	
Conectiv/ ACE	5.12	5.260	5.529	5.473	5.513	6.648	20.6%
JCP&L	4.87	5.042	5.587	5.325	5.478	6.570	19.9%
PSE&G	5.11	5.386	5.560	5.479	5.515	6.541	18.6%
Rockland	5.82	5.557	5.601	5.566	5.597	7.179	28.3%

Source: New Jersey Board of Public Utilities, various years.

Maine

Maine has used a competitive bidding procurement process to determine the standard offer rates since 2000. The bidding process is conducted by the Maine Public Utilities Commission. Maine's restructuring law required complete divestiture of the utilities' generation assets and the distribution companies cannot participate in the bidding (affiliates of the distribution cannot provide more than 20 percent of the standard offer service in the company's service territory). The most recent bidding round for two companies, Central Maine Power and Bangor Hydro Electric, resulted in the standard offer rates from March of 2005 through February 2006 to increase by over 40 percent for both companies' residential customers. Nearly all the residential customers in the two companies' territories are on this standard offer rate for generation service. Prices for large and medium sized businesses will also increase in September of 2005 (see Table 3 for details).

Massachusetts

Massachusetts ended its "standard offer service" (the state's transitional generation service) and began "basic service" March 1, 2005, for residential customers that have not chosen a competitive supplier (almost 97 percent of the residential customers in the state). The distribution companies purchase electricity on the market following the procedures of the Massachusetts Department of Telecommunications and Energy. The rate increases for the six affected distribution companies in the state ranged from just over four percent for Massachusetts Electric Company to 28 percent for Western Massachusetts Electric Company.

Maryland

Maryland has a competitive bidding procurement process for small commercial and medium sized commercial and industrial customers on "standard offer service" for the four major electric distribution companies in the state and for residential customers of two distribution companies. The generation portion of the rate for residential customers of Potomac Electric Power (PEPCO) increased by 26 percent and the average annual bill increased by about 16 percent in 2004. For 2005, PEPCO's residential customers generation standard offer will increase by 6.6 percent and the overall annual bill will increase by 4.6 percent. Delmarva Power and Light (DPL or Conectiv) residential customers had the generation portion of their bill increase by 19 percent and the average annual electric bill increased by about 12 percent in 2004. DPL customers in 2005 will have the generation component of their bill increase by 8.7 percent and the total annual bill will increase by 5.8 percent.

An Alcoa aluminum smelting plant, Eastalco Works near Frederick, Maryland, is facing much higher electricity prices when its contract with Potomac Edison/Allegheny Power (a distribution company of Allegheny Energy) expires on December 31, 2005. Eastalco is the biggest single electricity consumer in the state and accounted for 13 percent of Potomac Edison/Allegheny Power's revenue in 2004. Electricity accounts for about one-quarter of the price of raw aluminum, and, at current power prices, Eastalco operators claim that the plant will have to be shut down, eliminating 639 jobs.[12] The parent company of Potomac Edison/Allegheny Power, Allegheny Energy, claims that

[12] "Alcoa Plant in Fredrick a Long Shot to Stay Open," Jay Hancock, *Baltimore Sun*, June 15, 2005 and "Alcoa to Seek State Government's Help to Limit Power Costs at Maryland Plant: Sharp Rate Increases Expected After Allegheny Contract Ends," Associated Press, June 4, 2005.

the current special contract has been in effect since 1994, and that PJM average load-weighted wholesale prices have increased 83.5 percent from 1998 to 2004. Allegheny Energy also states that Potomac Edison/Allegheny Power is a delivery company and not an electric generation company that now obtains its electricity through the Maryland competitive bidding process. Allegheny Energy, that is an electricity supplier, only serves wholesale customers and does not serve retail customers.[13]

Over 92 percent of PEPCO residential customers and nearly all the residential customers of the other three major distribution companies in the state receive standard offer service.

Ohio

Ohio also attempted to find competitive suppliers for its standard offer generation service for the FirstEnergy Corporation companies that serve northern and parts of central Ohio. Ohio used an auction design similar to New Jersey's descending clock auction to test the rates agreed to in a "Rate Stabilization Plan" against a market price. The auction was held on December 8, 2004, and the Ohio Commission rejected the results of the auction the next day. FirstEnergy was then directed to implement the Rate Stabilization Plan pricing for standard offer service on January 1, 2006, that was previously approved by the commission. Another auction will be attempted in late 2005. The Ohio Commission has stated that the Rate Stabilization Plans agreed to with FirstEnergy (and other Ohio companies) are intended "to help ensure that electric consumers do not face ‘sticker shock' from electric rates when the market development period [the state's transition period] ends on December 31, 2005." They also noted that ". . . it was assumed that a regional market would develop quickly and that the retail markets would follow. . . . Thus far, the electric marketplace has not developed as hoped."

[13]“Facts on Allegheny Energy and The Competitive Electricity Market in Maryland,” Allegheny Energy, June 3, 2005.

Texas

Another state that is of considerable interest is Texas. Texas has been very assertive in the state's development of both wholesale and retail markets. Due to early success in terms of alternative retail suppliers that have offered prices below the utility "price-to-beat" rate and customer switching activity to these alternative suppliers, Texas is often depicted as a success for retail competition. The price-to-beat is used by customers to compare alternative suppliers. The price-to-beat rate is administratively set (not by a competitive procurement process) by the Public Utility Commission of Texas and is adjusted to reflect changes in natural gas and purchased energy market prices.

Since retail access began in Texas on January 1, 2002, the residential price-to-beat rates have increased substantially for customers in the five investor-owned companies' service territories in the ERCOT region of the state. Between January 2002 and March 2005, the price-to-beat rate has increased by just over 30 percent in TXU Electric & Gas, nearly 38 percent in Central Power and Light and Texas-New Mexico Power, and almost 45 percent in Reliant Energy and West Texas Utilities. About 80 percent of residential customers are paying the price-to-beat rate. The residential price-to-beat rates from January 2002 to March 2005 in the five Texas service territories with retail access are shown in Figure 24.

The increases in the price of natural gas over the last few years explain why the price-to-beat rates have also been increasing. However, an analysis of rates of different companies across the state shows that rates increased on average 43 percent from January 2002 to October 2004 for customers of the restructured utilities, but rates for customers of non-restructured and still regulated utilities increased by 17 percent and rural electric cooperative rates increased by 9 percent.[14] The price of natural gas is being used to adjust the rates to reflect the marginal cost of producing power in the state, in order to simulate a market outcome. But under cost-based regulation, the rate

[14]As reported in "Electricity up more in deregulated areas of Texas," *Fort Worth Star-Telegram*, Texas Knight Ridder/Tribune Business News, April 19, 2005 and "Texas Electricity Deregulation Hasn't Aided Small Power Users," *The Wall Street Journal*, May 20, 2005.

is adjusted for the portion of generation that uses natural gas and for other costs that may have increased or decreased as well, in proportion to actual or expected utilization.

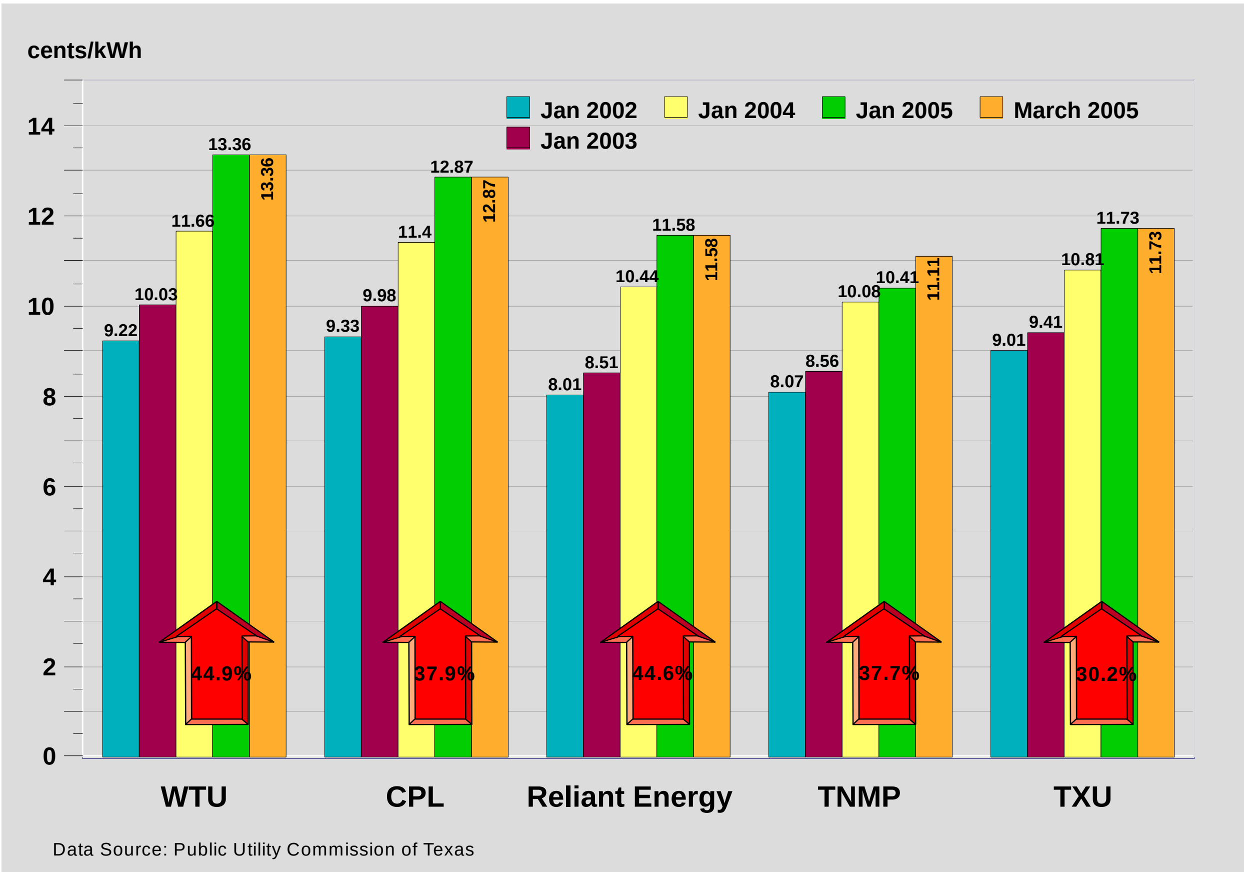


Figure 24. Residential “Price-to-Beat” rates in five Texas service territories and percentage increases, January 2002 to March 2005.

Summary of State Restructuring Activity

Table 3. State restructuring summary.

State	Investor-owned utilities/distribution companies	Restructuring legislation	Discounts
	Updates of Interest		
Arizona	Arizona Public Service Company (APS) and Tucson Electric Power Company (TEP)	Restructuring legislation passed in 1998. Retail access began January 1, 2001.	
	In 2002, the Arizona Corporation Commission (ACC) eliminated the requirement that utilities divest generation assets and that all power needed for standard offer service be purchased in the market. In an April 2005 Order, the ACC authorized APS to place generation assets into rate base. Retail access is allowed, however, rates were determined in a way that more closely resembles traditional regulation. Arizona's retail market was just beginning in January 2001 when the western power crisis was about at its peak. The interest that competitive suppliers had at the beginning disappeared and there are currently no shopping customers in the state, except large industrial customers on special contracts.		
California	Pacific Gas and Electric Company, Southern California Edison, San Diego Gas and Electric	Restructuring law passed in 1996. Retail access began April 1998.	Restructuring legislation required a 10% rate cut.
	In September 2001 retail access is suspended by the PUC.		
Connecticut	Connecticut Light & Power and United Illuminating	Restructuring law passed in 1998, revised June 2003.	Legislative discount: 10% below the 1996 rates, same rates in effect in 1999.
	Original Standard Offer service set to run from January 1, 2000 through December 31, 2003, for residential and small business customers. Revised restructuring law created the "Transitional Standard Offer Period," in effect from January 1, 2004 through December 31, 2006 – ended 10% rate reduction. Standard Offer rate increased 10.3% on January 1, 2005.		

Delaware	Delmarva Power & Light Co. (Conectiv Power Delivery) and Delaware Electric Cooperative (DEC)	Restructuring law passed March 1999. Retail access phased-in beginning October 1, 1999 for large Conectiv customers and ended April 1, 2001 when all customers were eligible. Rate freeze extended to March 2006 as part of merger of PEPCO and Connective and March 2005 for DEC.	Residential rate cut of 7.5% for Conectiv customers and a rate freeze for Delaware Electric Cooperative customers.
	Rate caps end for Delmarva Power & Light Co. customers on May 1, 2006, were originally set to end September 2003, but were extended by merger resolution. Rate caps ended on March 31, 2005, for Delaware Electric Cooperative customers. In March 2005, the Commission approved Delmarva Power & Light Company as the Standard Offer Service supplier for after May 1, 2006 – customer prices will be determined by a competitive bidding (RFP) process and in the wholesale market. Commission approved a settlement also in March 2005 that established new rates for Delaware Electric Cooperative customers – for residential customers the supply rates increased approximately 14.5% and distribution rates decreased approximately 24%, resulting in almost no overall rate change.		
District of Columbia	Potomac Electric Power (PEPCO)	Restructuring legislation passed 1999. Retail access began January 1, 2001.	The Commission in 1999 approved a reduction in PEPCO's residential rates by 7% between January 1, 2000 and February 7, 2001, and capped at the reduced levels through February 7, 2005. Electric rates for customers who participate in PEPCO's Residential Aid

			discount ("RAD") program are capped until February 2007.
	*PEPCO's distribution service rates are capped until August 2009 for RAD customers and until August 2007 for all other customers. PEPCO (which sold all its generation plants by January 2001) is required to procure wholesale generation through a competitive bidding solicitation that is overseen by the Commission. Beginning February 2005, bills for most residential customers in DC increased on an average annual basis by approximately 18%, or about $10.00 per month. Residential bills increased approximately 26% during the winter and 9% during the summer. Small commercial customer rates increased by approximately 24% on average for the year.		
Illonois	Central Illinois Public Service Company (AmerenCIPS), Central Illinois Light Company (AmerenCILCO), Commonwealth Edison, Illinois Power Company (AmerenIP)	Restructuring law passed in 1997. Retail access phased-in, beginning October 1,1999, retail access for residential customers began on May 1, 2002. Transition period until January 2007.	15% in 1998 and an additional 5% for Commonwealth Edison and Illinois Power residential customers. Smaller discount for customers in other areas.
	The Illinois restructuring legislation's transition period ends on December 31, 2006. To prepare for this, the Illinois Commerce Commission (ICC) hosted a series of workshops called the "Post 2006 Initiative," in 2004 to discuss the states competitive options. Currently, before the ICC, are proposals from the Ameren companies and Commonwealth Edison to conduct New Jersey-type "BGS" auctions for power procurement after the transition period ends. There is no residential shopping in Illinois and, as noted in a December 2004 ICC staff report, "no alternative supplier has even applied for certification to serve residential customers."		
Maine	Bangor Hydro-Electric, Central Maine Power, Maine Public Service Company	Restructuring law passed in May 1997. Retail access began March 2000. All standard offer prices determined by a bidding process.	Rate Reductions from 2.5% to 15%

	*In December 2004, the Maine PUC accepted bids approximately 40% higher for standard-offer service (SOS) generation service starting in March 2005 through February 2006 for small commercial and residential customers. The new prices reflect current wholesale energy prices which have risen substantially since SOS prices were set 3 years ago. More than 99% of Maine's residential and small commercial load is currently supplied by SOS. Prices for large and medium sized businesses will increase in September, following bids accepted by the Maine Public Utilities Commission. The bids were for new standard-offer energy prices for medium and large commercial and industrial customers of Central Maine Power Co. and Bangor Hydro-Electric Co. They cover a six-month term beginning Sept. 1. For CMP customers, the new prices are about 8.3 cents a kilowatt hour for both the medium (up 22%) and large (up 27%) classes. For Bangor Hydro customers, the average prices are about 8.5 cents/kwh for the medium class (up 23%) and 7.8 cents/kwh for the large class (up 24%). The rate increases reflect the higher prices charged by power generators, not the delivery services offered by CMP and Bangor Hydro-Electric. The increases are tied to the cost of imported fuel in New England, the PUC said. They also may reflect potential capacity costs pending before federal energy regulators. Standard-offer service is the default supply for customers that don't purchase energy from a retail supplier or through an aggregator. Roughly 15 percent of the electric load of CMP and Bangor Hydro's large customers, and 65 percent of medium customer load are supplied by standard-offer service. Source: "Electric rates to rise sharply for larger businesses in Maine" Knight Ridder/Tribune Business News - Tux Turkel, Portland Press Herald, Maine.		
Maryland	Allegheny Power (APS), Baltimore Gas & Electric (BG&E), DPL/Connectiv (DPL), Potomac Electric Power Company (PEPCO)	Restructuring law passed in April 1999. Residential transition ends July 1, 2008 for Allegheny Power (APS) and July 1, 2006 for Baltimore Gas & Electric (BG&E). Transition ended July 1, 2004 for DPL/Connectiv (DPL) and July 1, 2004 for Potomac Electric Power Company (PEPCO).	APS: About 7% reduction for residential, BG&E: 6.5% reduction for residential, DPL/Connectiv: 7.5% reduction for residential, PEPCO: 3% reduction for residential.
	*July 1, 2004, all Standard Offer Service price caps remaining for non-residential customers were lifted. SOS caps were lifted for residential DPL and PEPCO customers in July 1, 2004. * On April 2, 2004, the Maryland Public Service Commission (PSC)		

	announced the results of a bidding process secured electric suppliers to provide market priced electric Standard Offer Service for Maryland customers of investor owned electric companies whose fixed price electric service offerings are expiring. The process was established with the PSC's Order No.'s 78400 and 78710 (in Case No. 8908), which set the rules for Standard Offer Service procurement, pricing methodology, and technical details of the bidding process. The bidding rounds began in February and concluded in March. Supply services under these contracts began June 1, 2004. (See Maryland section of text for 2005 results.)		
Massachusetts	Boston Edison, Cambridge Electric, Commonwealth Electric, Eastern Edison, Fitchburg Gas and Electric, Massachusetts Electric Company, Western Massachusetts Electric Company.	Restructuring law passed in November 1997. Retail access began March 1998. Transition until March 1, 2005.	Discount of 10% for all standard offer customers.
	*Standard Offer Service (SOS) expired February 28, 2005. SOS rates increased approximately 7.5% as customers were shifted to default rates. Default rates are set every six months (see Massachusetts section in text).		
Michigan	Alpena Power Company, American Electric Power Company, Edison Sault Electric Company, Detroit Edison Company, Consumers Energy Company	Restructuring law passed in June 2000. Retail access began January 1, 2002. Transition rate caps until January 2004.	5% rate reduction through the end of 2003 for every residential electric customer of Detroit Edison Company and Consumers Energy Company.
	*Per state law as of January 1, 2005 all member owned co-op customers now also have open access to suppliers.		
Montana	Montana Dakota Utilities, Energy West Montana, and Northwestern Energy	Restructuring law passed in 1997. Retail access began 1998 (for large customers). In 2001 - transition period	2 year rate freeze began July 1998.

		extended to 2007. In 2003 - transition period extended until 2027.	
	*On November 1, 2004, NorthWestern Energy emerged from Chapter 11 bankruptcy. The company disposed of many non-utility assets, simplified its corporate structure and reduced overhead costs. The Company's debt was reduced from $2.2 billion to approximately $850 million including the effects of refinancing. Legislation extended the transition period for residential customers to July 1, 2027.		
New Hampshire	Public Service Company of New Hampshire (PSNH), Granite State Electric Company (GSEC), Unitil Energy Systems, Inc. (UES), and New Hampshire Electric Cooperative, Inc. (NHEC).	Original restructuring law passed in 1996. Retail access implementation was delayed by litigation. GSEC began retail access August 1998, PSNH began May 2001, and UES companies began May 1, 2003.	10% rate reduction for PSNH residential customers.
	*The Public Utilities Commission approved a proposal in November 2003 that encourages large commercial and industrial customers to switch from PSNH to electricity purchased from competitive suppliers. The Retail Energy Services, or RES program, was designed for customers whose billing demand is one megawatt or greater. If they agree to join, such customers may choose a supplier and receive a per-kilowatt-hour credit against the energy portion of their electric bills. It is hoped that this credit will provide incentive to a customer to switch to a competitive supplier. Currently, the transition service price is lower than the market price for electricity, so there is no incentive for customers to switch. The RES program is designed to encourage comparison shopping. It went into effect on February 2004 and will end after two years. Most residential customers receive Transition Service.		
New Jersey	Connectiv, GPU/ FirstEnergy Company - Jersey Central Power & Light, PSE&G, Rockland	Restructuring law passed in February 1999. Retail access began August 1999. Transition ended August 2003.	5% in 1999 and an additional 10% over the next 3 years.

<table>
<tr><td></td><td colspan="3">*New Jersey regulators okayed an electricity buying plan for the state's four utilities in November 2002. According to the plan, the Board of Public Utilities (BPU) will conduct two auctions. The first will provide energy at hourly prices to large industry and business customers. The second will be a fixed-price auction (or "Basic Generation Service" auction) to provide energy to homeowners and small businesses. This multi-phased plan went into effect August 1, 2003 and will conclude on May 31, 2006. (Details on past auctions are in last year’s Performance Review, pp. II-17 to II-23.)

*The state Board of Public Utilities (BPU) voted a rate increase for Public Service Electric & Gas Company (PSE&G) customers in July 2003. This vote, together with the end of price controls in August 2003, caused electric rates to increase by as much as 15 percent for customers of PSE&G. The result was that rates reverted to approximately the same level as when the deregulation act went into effect in mid-1999.

The total cost of power purchased in the seven day February 2004 auction (as certified by the Board of Public Utilities) amounted to an estimated $5.1 billion, resulting in lower electric rates and a savings of $24 million for ratepayers annually. Most of New Jersey’s 3.2 million residential customers had their bills drop by anywhere from $0.43 cents to $1.02 per month beginning in June 2004. (NJ Consumer Advocate)

See New Jersey summary in text for the 2005 auction results.

FERC approved Excelon/PSEG merger in July 2005 – other agency decisions are still pending (including the NJBPU).</td></tr>
<tr><td>New York</td><td>Central Hudson, Consolidated Edison, New York State Electric and Gas, Niagara Mohawk Power Company, Orange & Rockland Utilities, Rochester Gas and Electric</td><td>Restructuring implemented by Commission orders, no restructuring law passed. Retail access and transition periods differ by company. See below.</td><td>Discounts differed by company. See below.</td></tr>
<tr><td></td><td colspan="3">*The New York State Public Service Commission (PSC) initiated deregulation discussions with each investor-owned utility individually. The PSC approved utility restructuring plans that dealt with rate levels, retail competition, and corporate restructuring of all of New York's seven major electric utilities. The transition to competition began in 1998 for the utilities with approved plans. Each plan is different.</td></tr>
</table>

From DOE **“**Status of State Electric Industry Restructuring Activity” 2003

Central Hudson Gas & Electric

Retail access began: September 1998

Rates frozen at 1993 levels until June 30, 2001

Full Retail Access - July 1, 2001

Consolidated Edison

Retail access began: June 1, 1998

25% rate reduction for 5 years for large industrial, 10% for all other customers phased in over 5 years

Full Retail Access – December 2001

Long Island Power Authority

January 2002: LIPA opened up the Long Island electricity market completely on January 17, 2002, seven years ahead of schedule. LIPA is not subject to PSC rate regulation.

New York State Electric & Gas

Retail access began: August 1, 1998

Rates capped until 2003, after 2003, delivery rates are regulated by the PSC, while energy rates will be set by the market. Also a 5% rate reduction for industrial and large commercial consumers for five years (five reductions of 5% each), and residential and small commercial/ industrial consumers received 15% reduction by third year and 5% by the fifth year.

Full Retail Access - August 1,1999

Niagara Mohawk Power

Retail access began: September 1, 1998

Residential and commercial customers received a 3.2% phased in decrease over three years. Industrial received about a 13% phased in rate reduction. Rates for electricity and delivery were set until September 2001. Rate changes after that period must go through the PSC.

Full Retail Access - August 1, 1999

As part of merger agreement when National Grid bought Niagara Mohawk “calls for National Grid to lower electricity prices and freeze natural gas delivery rates for 10 years.” Essentially increasing the transition to 2011.

Orange and Rockland Utilities

Retail access began May 1, 1998

Rates fell by 4%, 4%, and 14% for residential, commercial and industrial respectively in 1995-1996. This was followed by two 1% reductions, in 1997 and 1998, for residential costumers and a 8.5% drop in 1997 for large industrial customers.

Full Retail Access - May 1, 1999 includes energy and capacity

Rochester Gas & Electric

Retail access began July 1, 1998

	Rates set until mid 2002, residential, commercial, and industrial consumers received 7.5%, 8%, and 11.2% rate reductions, respectively, to be phased in over five years. Full Retail Access - July 1, 2001, includes all customers, energy and capacity. Delivery charges are regulated by the PSC, energy prices are determined by the market. **On August 25, 2004, the Commission adopted the Statement of Policy on Future Steps Toward Competition in Retail Energy Markets. The Policy Statement sets forth the Commission's goals and visions for the further development of robust retail energy competition in New York and provides a flexible framework for the Commission to analyze and respond to evolving market conditions and thereby to facilitate market development as required. Central Hudson's was approved May 2005.		
Ohio	AEP/Columbus Southern Power Company, AEP/Ohio Power Company, Cincinnati Gas & Electric Company, Dayton Power and Light Company (DP&L), First Energy/Cleveland Electric Illuminating Company, First Energy/Ohio Edison Company, First Energy/Toledo Edison, Monongahela Power Company	Restructuring law passed in July 1999. Retail access began January 1, 2001. Original transition until December 31, 2005 and through Dec 2003 for DP&L – later extended to Dec 2005. Extended transition through Dec 2008 for AEP and FirstEnergy companies.	5% rate reduction on generation portion and 5 year rate freeze (was to end December 2005), except DP&L (3 year freeze, and 5% reduction, then in 2.5% reduction of generation costs starting in 2006 and lasting 3 years). AEP extended 3 years (through 2008), allowed 3% increase per year. FirstEnergey Rates are frozen until 2008 except fuel and tax adjustments.

	*Most retail activity has been in the northern part of the state (the area served by the FirstEnergy companies). That area has historically had higher prices in the state. Most residential switching customers have used the Community Choice aggregation option available through the state. The rest of the state has shown almost no movement of residential customers. *Though Dayton Power and Light Co (DP&L) was to start charging market prices for power in January 1, 2004, fears of volatile rates caused certain public-interest groups to make a deal with the company, freezing distribution rates through 2008. The plan will allow DP&L to file for rate increases in 2006 to pay for higher costs. **Rate Stabilization Plans extended for First Energy, AEP, DP&L, and Cinncinati Gas & Electric. AEP Extended for three years staring Jan 2006 and can increase generation charges by 3% for all customer classes. ** The Public Utilities Commission of Ohio (PUCO) adopted a Rate Stabilization Plan (RSP) for FirstEnergy that provided for a competitive bidding process, or auction, to be conducted on FirstEnergy's electric load to see if lower rates could be obtained. The auction was conducted in December 2004. The PUCO rejected the results of the auction, finding that the RSP provided lower electricity rates. The PUCO will hold additional auctions in the future to continue to test the market for lower generation rates. **Monongahela Power chose not to file an RSP. Instead, the company filed an application to implement a fixed and variable rate, market-based standard service offers to be determined by a competitive bidding process. On June 14, 2005, the PUCO directed Monongahela Power and AEP to pursue potential terms and conditions for transferring Monongahela Power's Ohio territory to AEP. In August 2005, Allegheny Power (the delivery company of Allegheny Energy, that includes Monongahela Power) announced an agreement to sell its Ohio service territory's transmission and distribution assets to American Electric Power's Columbus Southern Power subsidiary for net cash proceeds of approximately $55 million.		
Pennsylvania	Allegheny Power, Duquesne Light, Metropolitan Edison, PECO Energy, Pennsylvania Energy, Pennsylvania Power, Pennsylvania Power and Light, UGI Utilities	Restructuring law passed in December 1996. Retail access phased in beginning January 1999 and reached all customers by January 2001.	No required reductions in legislation, some companies had them in first year and phased out over three years.

	*New regulations proposed December 2004 requires default suppliers for small retail customers to offer at least 1 year contracts at fixed rates and obtain their power through competitive bids. These rules apply to "last resort" suppliers – those which supply power to customers who can't or don't choose to receive power through alternative suppliers. Current default rates are capped as a result of the restructuring related to the Electric Choice Law. The intent of these new regulations is to maintain service availability at reasonable terms even after the rate caps expire. Duquesne prices are open, and set by the market.		
Rhode Island	Narragansett Electric	Restructuring law passed in August 1996. Retail access phased-in beginning July 1997. 2002 legislation requires utilities to offer Standard Offer Service until January 2009.	7% reduction.
Texas	Central Power and Light, Reliant Energy, TXU Electric and Gas, TXU SESCO, Texas-New Mexico Power Company, West Texas Utilities	Restructuring law passed in June 1999. Retail access began January 2002. Transition is at least 3 years or until 40% of the power consumed within their certified service areas is provided by competitors.	Rates frozen at September 1999 levels. A bundled rate 6% less than its affiliated transmission and distribution utility rates for its residential and small commercial customers.
	See Texas update in text. *Entergy, the major provider of energy in Southeast Texas, announced in June 2004 that it has halted current efforts to move to retail open access in Southeast Texas. PUCT denied Entergy's application to create an independent organization to manage the Entergy transmission system in Texas. Entergy was also told to terminate its current pilot program and delay retail open access until a FERC approved RTO or some other independent entity certified by Texas law is in place. The company was asked to explore joining the Southwest Power Pool RTO as an alternative. Affiliated retail electric providers are required to sell electricity at the price to beat until January 2007.		

Virginia		Restructuring law passed in March 1999. Retail access began January 2002. Transition extended until 2010.	
	See section on the status of competition in the Commonwealth.		

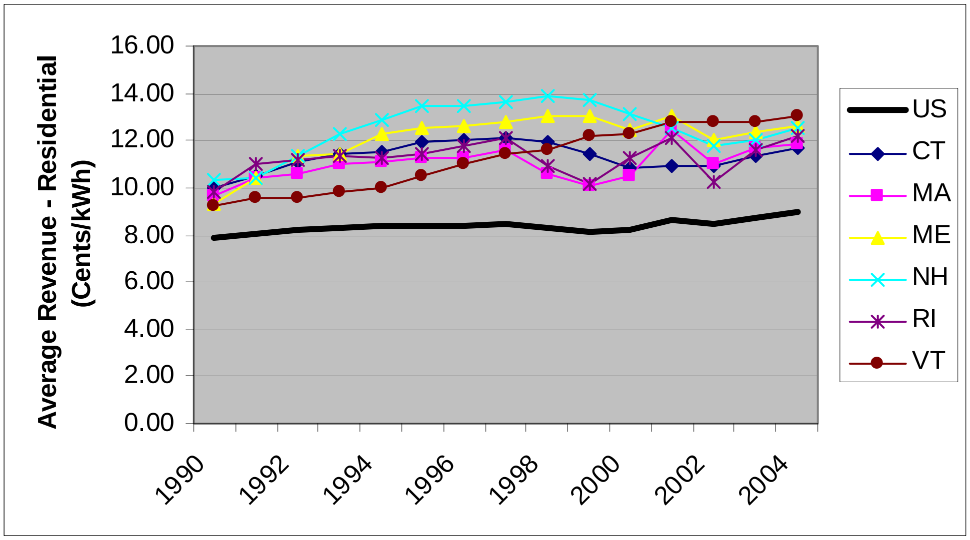
*Source: From corresponding state at
http://www.eere.energy.gov/femp/program/utility/utilityman_staterestruc.cfm
**Source: Corresponding state public utility commission

Retail Price Trends

Similar to the paper by Apt,[15] that was summarized earlier in this report, U.S. Department of Energy, Energy Information Administration[16] average revenue data (essentially, the average price for the sector) were plotted to see price trends from 1990 through 2004. The graphs below are shown by region for the residential, commercial, and industrial sectors.

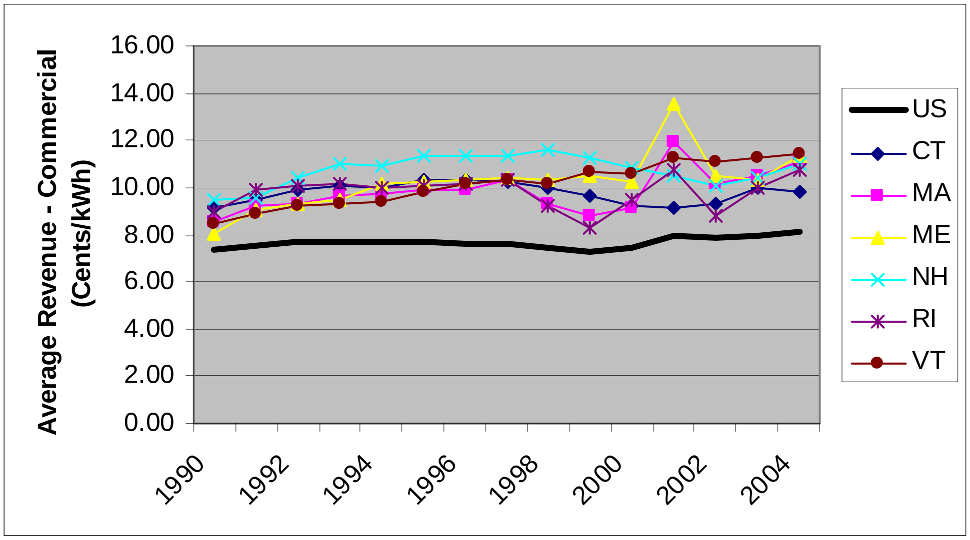
New England

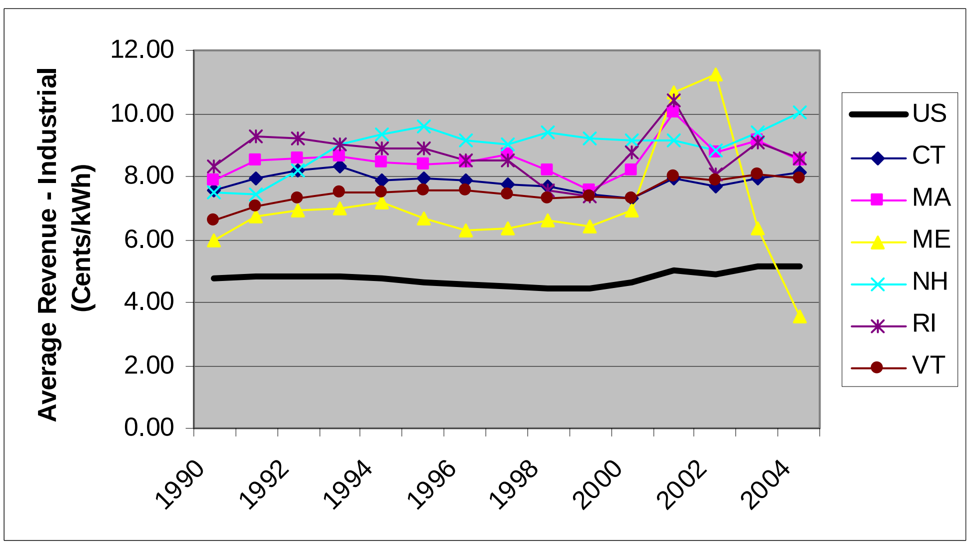
Average revenues for the New England states has exceeded the national average since 1990. The only exception to this was average revenues for service to industrial consumers in Maine in 2004. However, prices in Maine, though not shown on this graph, rebounded in 2005. The drops seen in the late 1990s in states like Massachusetts, Rhode Island, and Connecticut (and New Hampshire after 2000) residential prices can be attributed to rate reductions that came with the restructuring plans of these states. Massachusetts prices have returned to pre-discount levels. In 2001, both commercial and industrial consumers saw prices spike in all states except



[15] Jay Apt, "Competition Has Not Lowered US Industrial Electricity Prices," Carnegie Mellon Electricity Industry Center, Working Paper CEIC-05-01, 2005. The paper is available at, www.cmu.edu/electricity.
[16] DOE/EIA, Form EIA-861, "Annual Electric Power Industry Report," 2005.

for Vermont (which is the only non-restructured state in this figure). Vermont has seen its average revenues in all three sectors climb steadily from 1990 to 2004 (residential and commercial Vermont prices went from near the lowest to near the top).

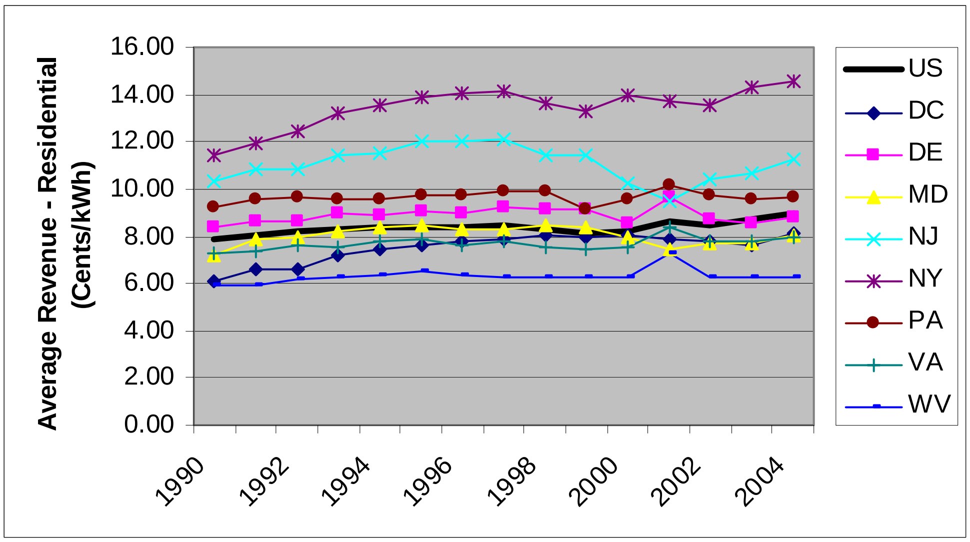


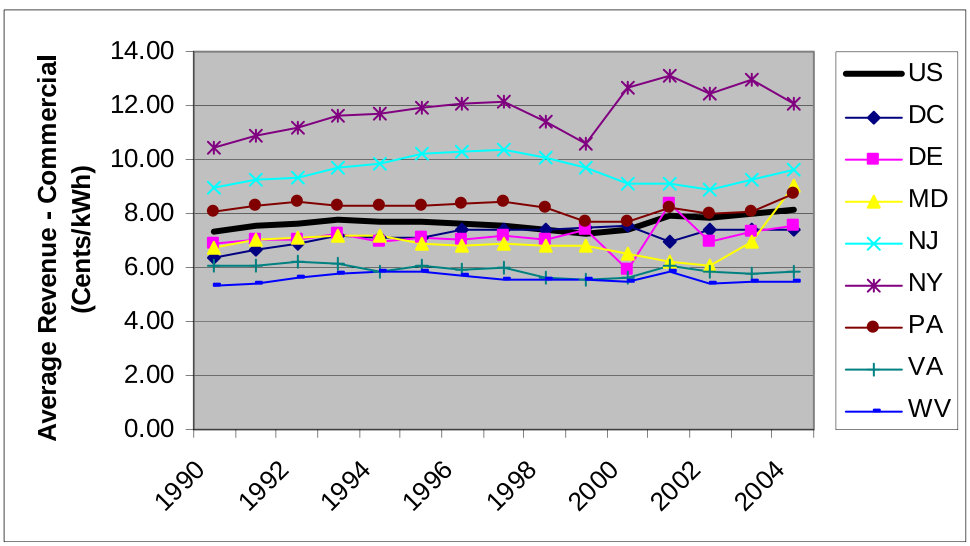


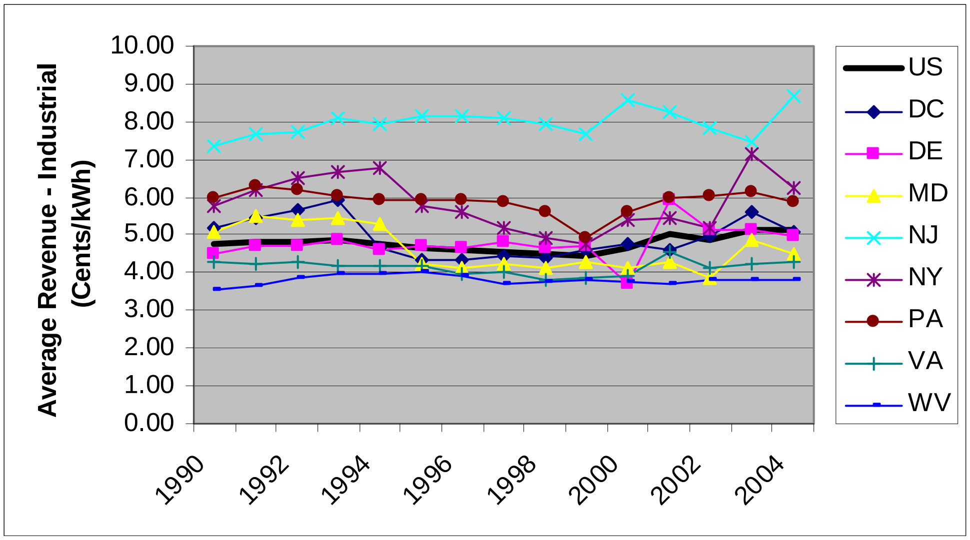
Mid Atlantic

New York and New Jersey had the highest average revenues of the three sectors. The Industrial sector is the only sector in which New York does not run the highest average revenues. Average revenues from New York industrial customers dropped from 1994 to 1999 before steady increases to 2003 where prices spiked.

Industrial average revenues in New Jersey were almost twice as high as the states in the region. Residential average revenues in New Jersey dropped in 1999 when the state opened retail competition, rolling rates back 5%. In 2000, average revenues from commercial consumers fell sharply in New York only to rebound the following year. Commercial average revenues for Maryland are on a significant upward trend since 2002. West Virginia offered the lowest in all three sectors, while Virginia stayed steadily below the national average in all sectors. Many of the states in this region stayed at or near the national average in all three sectors

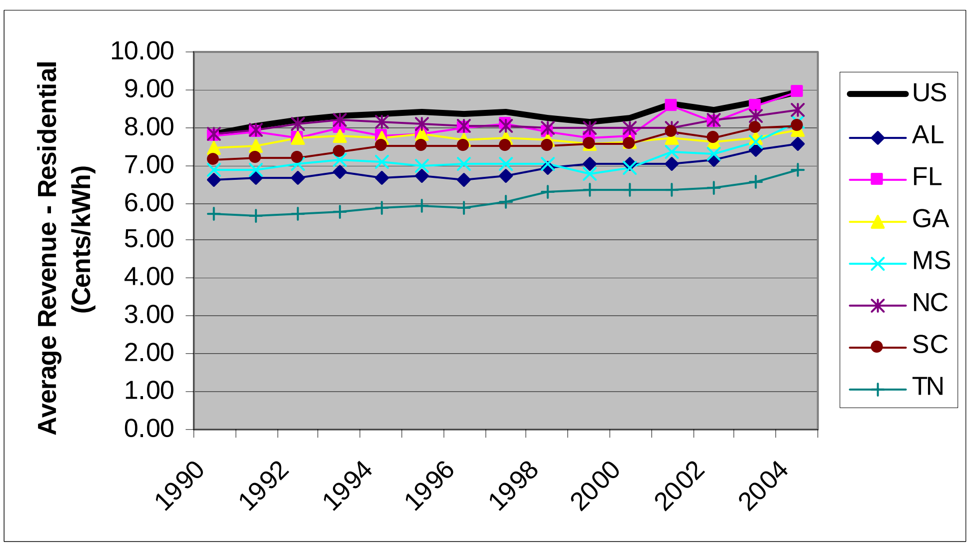


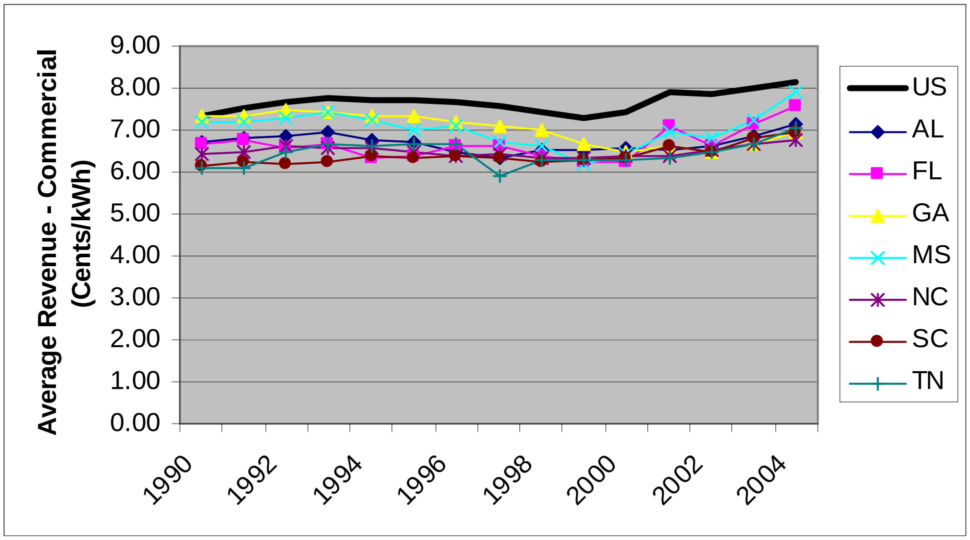


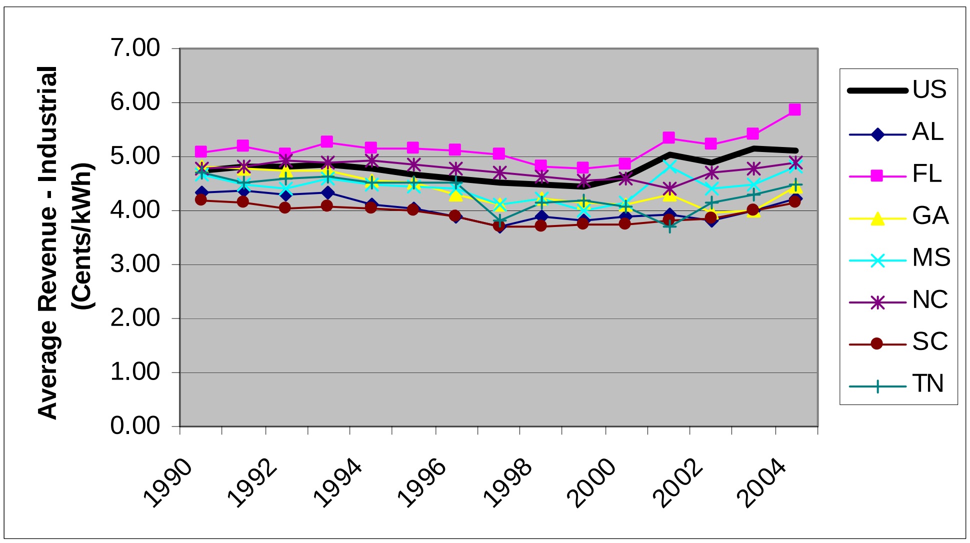


Southeast

With the exception of industrial sector average revenues in Florida, average revenues for the region stayed at or below the national average in all sectors. Average revenues appear to move in a similar path as the national average. In all three sectors, no state saw average revenues change by greater than 1.5 cents. Average revenues for the retail sector never top 9 cents (compare to New England where average revenues never went as low as 9 cents).

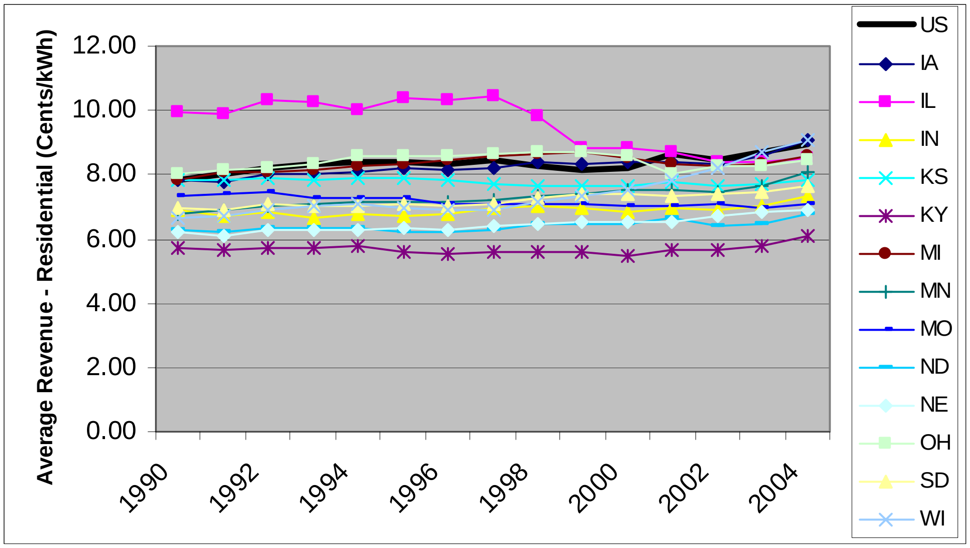






Midwest

Average revenues for this region tended to be at or below the national average. The Illinois residential sector started well above the national average, but when the state began restructuring in 1997, a 15 percent and another 5 percent roll back of rates reduced the state's average closer to the national average. All other states exhibited very little price fluctuation. The industrial sector of Missouri had prices decrease from 1990 to 2004, as did Illinois.


Average Revenue - Residential (Cents/kWh)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
1990
1992
1994
1996
1998
2000
2002
2004
US
IA
IL
IN
KS
KY
MI
MN
MO
ND
NE
OH
SD
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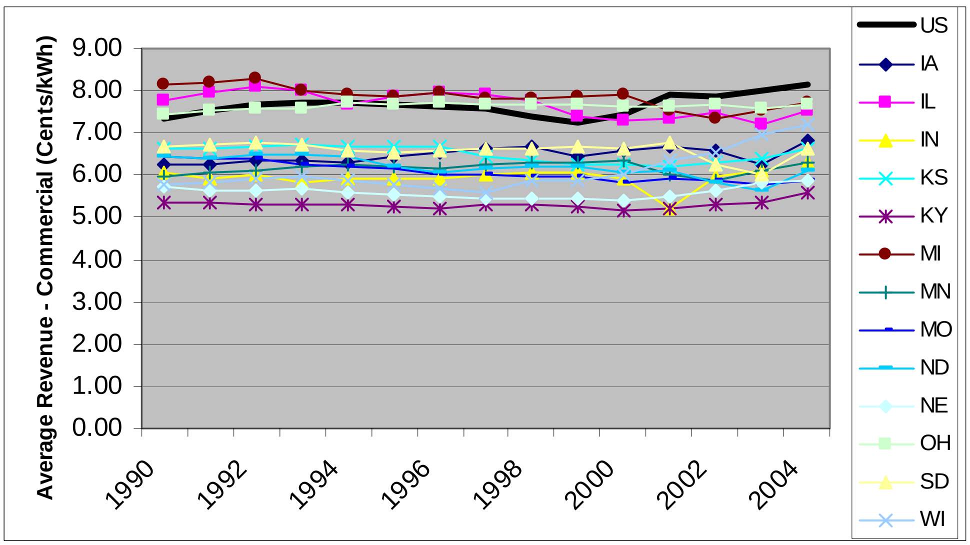
Average Revenue - Commercial (Cents/kWh)
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1990
1992
1994
1996
1998
2000
2002
2004
US
IA
IL
IN
KS
KY
MI
MN
MO
ND
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OH
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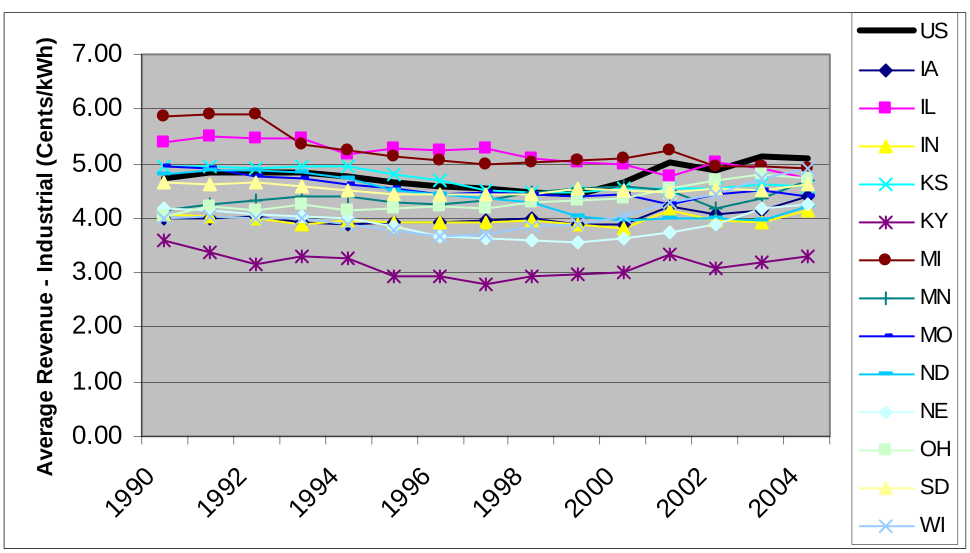
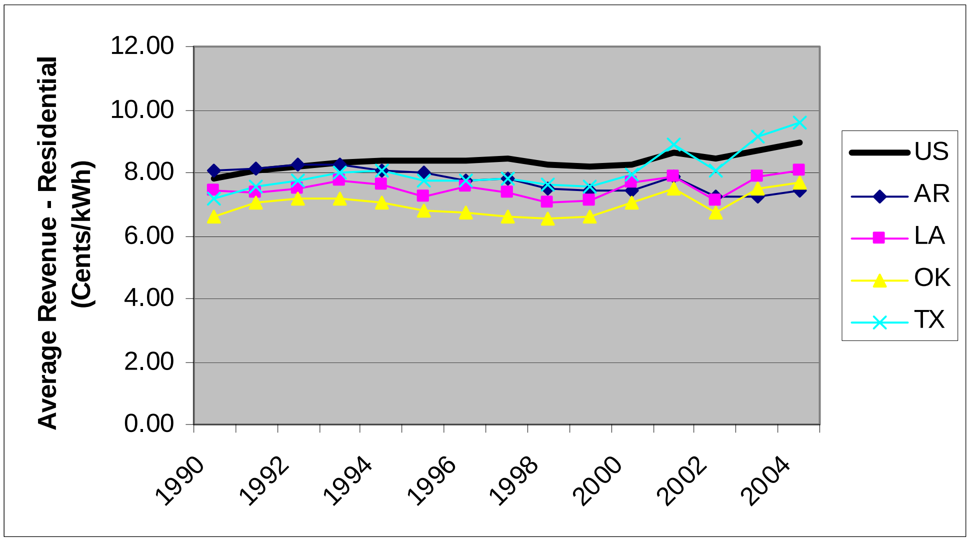
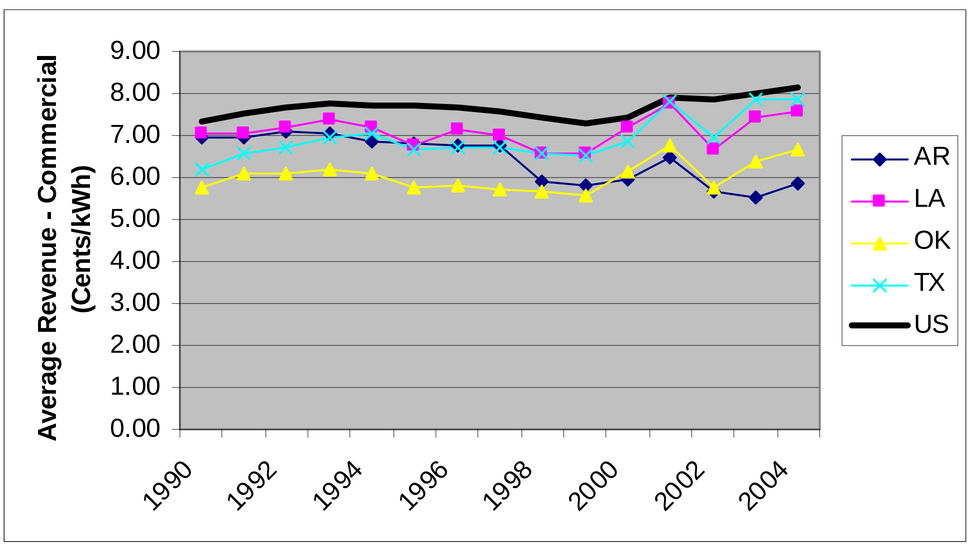
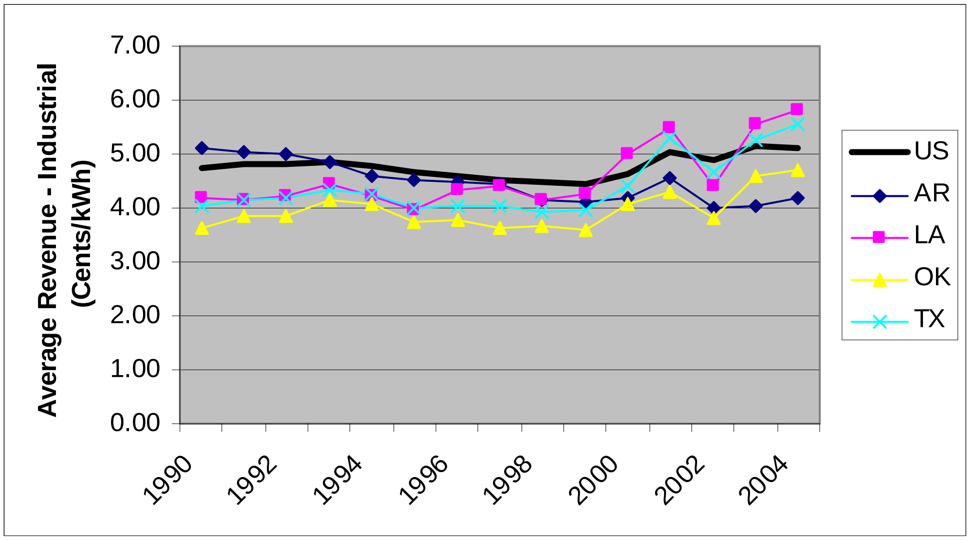

Average Revenue - Industrial (Cents/kWh)
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1990
1992
1994
1996
1998
2000
2002
2004
US
IA
IL
IN
KS
KY
MI
MN
MO
ND
NE
OH
SD
WI

Middle South

Most average revenues in this region tended to stay below the national average until 2001. In 2001, average revenues in the Texas residential and industrial sectors, as well as the Louisiana industrial sector, climbed above the national average. Arkansas average revenues decreased in all sectors. Oklahoma and Louisiana average revenues tend to be correlated in each sector, though Louisiana always had higher average revenues.

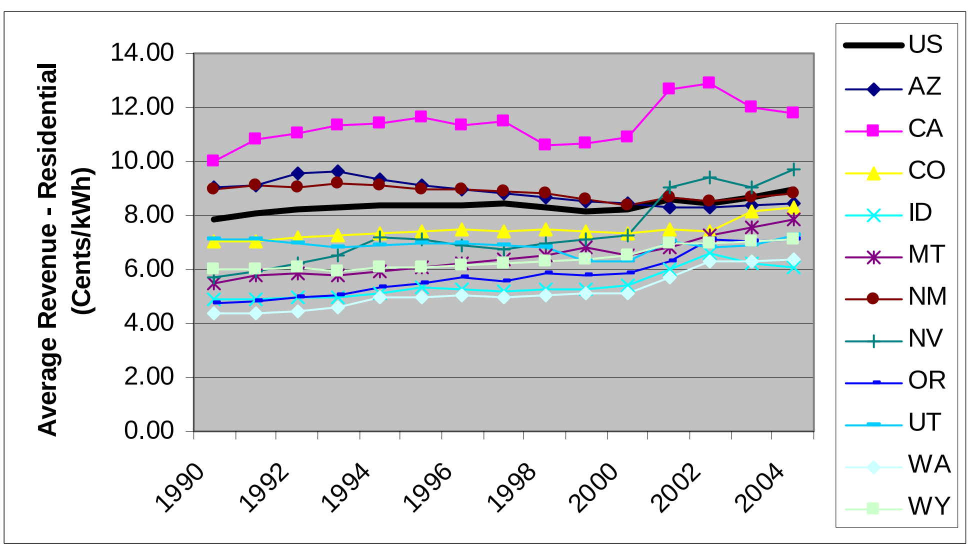


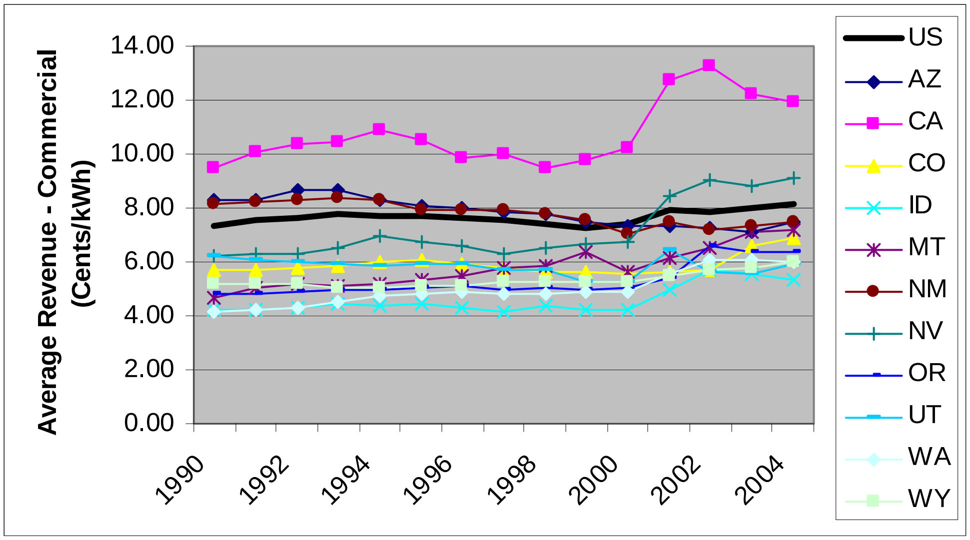


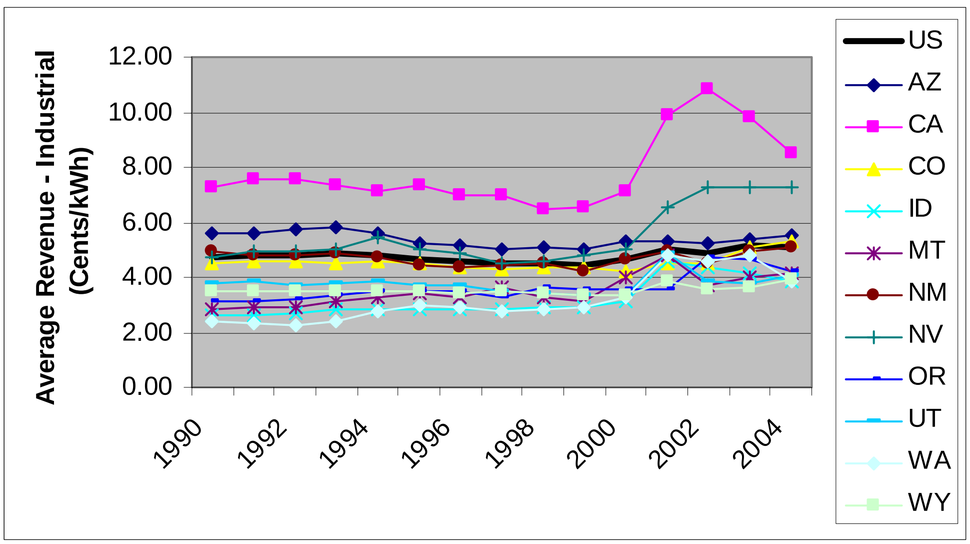


West

The most notable occurrence in the west since 1990 was the California and western power crisis. This caused average revenues in all sectors to rise dramatically in California. However, average revenues also jumped in Nevada and Washington. The average revenues of the residential sector in many states, including Oregon, Idaho, and Utah also increased, though to lesser degrees. Through all of this, the average revenues in New Mexico and Arizona decreased in the residential and commercial sectors, going from above the national average to slightly below. Average revenues in California, though down, have not returned to pre-crisis levels.




Average Revenue - Commercial (Cents/kWh)
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
1990
1992
1994
1996
1998
2000
2002
2004
US
AZ
CA
CO
ID
MT
NM
NV
OR
UT
WA
WY


Average Revenue - Industrial (Cents/kWh)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
1990
1992
1994
1996
1998
2000
2002
2004
US
AZ
CA
CO
ID
MT
NM
NV
OR
UT
WA
WY

Part B

Determining Industry Competitive Structure: Perspective on Results to Date

Given the results of electric industry restructuring so far, as discussed above, it is appropriate to consider why competition has not been, at least from the customers' perspective, more robust and beneficial as was once hoped. The desire here is to generate a constructive discussion on how to address the problems identified here.

A competitive market is usually defined as a market that has many buyers and sellers, has relatively easy entry to the market by sellers, where buyers have or can readily get product information, and no buyer or seller has the ability to significantly affect the market price. Few markets fit the textbook definition of a perfectly competitive market, however. Markets vary by degree of their competitiveness. A significantly imperfect market may have problems similar to an imperfectly regulated one, such as prices significantly above competitive levels, an inefficient allocation of resources, and fewer choices for customers.

Just how competitive a particular industry is depends on three general structural characteristics: (1) the market concentration or market share of the suppliers in the industry, (2) the ease with which alternative suppliers can enter a market, and (3) the overall market demand characteristics of the product. By examining these three characteristics together, the degree of competitiveness of any industry or market can be determined. More specifically, by examining these characteristics, the amount of control or price leveraging ability firms in the industry are able to exercise can be determined. The power to raise the price above what would occur in a competitive market is the firm's or group of firms' market power. No single characteristic of the three would indicate a firm has or had significant market power. For example, a firm could have substantial market share, for example 80 percent of the market, but if entry or increased output from other firms in the market was relatively easy and if customers also had suitable alternatives to the firm's product, then a firm's actual market power potential may be very low.

In the electric supply industry, all three characteristics clearly play an important role. Markets are very concentrated for most geographic regions of the country, even for multi-state wholesale regions. Market entry from other firms requires time to build new generation and is limited from outside the area by transmission constraints, which also require time to relieve. Mass storage of electricity for later use during peak hours is generally impractical for many regions of the country. Also, demand for electricity is very inelastic, particularly in the short-run (less than one year) since customers have few practical alternatives and the long life of major electrical appliances makes it difficult to respond to price changes quickly for most customers.

Economic theory would predict, because markets are relatively concentrated, peak hour supply is often very inelastic, that is, the quantity supplied is not very responsive to the price, and demand is also very inelastic, supplier market power is likely to be very significant, particularly during peak hours.

Market Concentration

To determine industry concentration, the Herfindahl-Hirschman Index (HHI) is often used. The HHI is calculated as the sum of the squared market shares of the suppliers in the market. To characterize market concentration, several RTO and ISO market monitors and others use the HHI. This use is based on the U.S. Department of Justice merger guidelines ("Horizontal Merger Guidelines," U.S. Department of Justice and the Federal Trade Commission) and has also been adopted by FERC for its merger policy. As defined by the Guidelines, if the HHI is less that 1000, the market is considered unconcentrated; an HHI between 1000 and 1800, the market is moderately concentrated; and an HHI above 1800, the market is considered highly concentrated.

Another tool, also used by several market monitors and FERC, is the pivotal supplier index. This measures the percentage of load that can be met without the largest supplier. A supplier's generation is considered pivotal when it is needed to meet the total market demand. This is calculated as the total supply capacity minus the largest supplier's capacity, then divided by the total market demand. If the index is less than 1.00, then at least a portion of the largest supplier's capacity is needed to meet total demand and that supplier is "pivotal."

The HHI and pivotal supplier index are screening tools used to examine market concentration. They do not give a definitive answer on a wholesale market's competitiveness, but may suggest that further analyses are warranted. A detailed market analysis should consider all three characteristics to make a judgement about a market's competitiveness.

These tests may be more difficult to apply to electricity markets, since transmission access and availability may limit the market to a relatively small area during peak times, but expand to a much larger size at other times, perhaps even during the same day. Attempts to characterize the market concentration should take this changing market size into account. Because of this difficultly, these concentration measures are rarely applied in a dynamic way to account for the changing market size.

Unfortunately, due to a number of mergers during the 1990s, and with renewed recent interest in several large mergers,[17] the current industry trend is toward more concentration, not less. Economic theory would suggest this increased concentration would make markets even less competitive.

Ease of Alternative Suppliers' Entry into the Market

The easier it is for alternative suppliers to enter a market, the more difficult it is for the existing supplier or suppliers to maintain a price above a competitive level and earn economic rent through the exercise of market power. There are three primary means that alternative suppliers (that is, suppliers that are not already in the market) can enter the market. They can either build new generation capacity within the region, use the transmission system to import their own generation from outside the area, or bring in purchased power from another source. Unfortunately, building new generation capacity and expanding transmission capacity to increase import capabilities are both difficult and take time to complete. The difficulty is due to the requirements for obtaining a site and the necessary permits and licenses to build from the various federal, state,

[17]These include the Exelon Corp. and Public Service Enterprise Group merger that has received FERC approval, but still has several federal and state agencies to finalize; the MidAmerican Energy Holding Co. and Pacificorp (with is part of Scottish Power PLC's) merger; and the Duke Energy Corp. and Cinergy Corp. merger.

and local agencies, obtaining financing for the project, the long lead times for construction, securing fuel supply and access, and other constraints, such as possible strong public resistance and the market risk and uncertainty faced by new entrants.

In recent years, the electric transmission system has been required to provide two critical functions. The first is the traditional and important task of maintaining system reliability. This includes the adequacy of the system to supply the energy and demand requirements of customers at all times and the system's operating ability to withstand sudden disturbances.

However, the electrical transmission system is now required to provide a second critical function, market support. In a 2003 report, the North American Electric Reliability Council noted that "the transmission system is being subjected to flows in magnitudes and directions that were not contemplated when it was designed or for which there is minimal operating experience."

An analysis prepared for the Edison Electric Institute and the U.S. Department of Energy (summarized in the 2004 Performance Review) found that transmission expansion has not been keeping pace with generation capacity and load growth. The analysis normalized the NERC transmission capacity data (MW-miles/MW-demand), and found that normalized transmission capacity declined by almost 19 percent between 1992 and 2002 and is projected to decline by 11 percent for 2002 to 2012. The report also showed that normalized transmission capacity declined in all ten reliability regions between 1989 and 2002, ranging from 14 percent to 27 percent declines. The author noted that: "[o]f the 416 transmission projects planned for the next 10 years, [footnote omitted] 95% are shorter than 100 miles, with an average length of only 18 miles. These numbers suggest that most planned transmission projects are local in scope and are not intended to address large regional issues."

If this trend continues as expected, it presents a serious challenge to the development of competitive wholesale markets. While this problem is recognized and is being addressed by ISOs and RTOs, at best, it will take many years to resolve the transmission constraints and reach a point that the transmission system can provide the open access needed to support a more developed competitive wholesale market.

Market Demand

The more responsive customer demand is, the more difficult it is for suppliers to maintain a price above competitive levels. The PJM Market Monitoring Unit (MMU) in its 2004 State of the Market report noted that "[t]he ability of load to respond to changes in price is a critical component of a competitive market which remains as yet undeveloped in the wholesale electricity market" (p. 87). The total MWh of load reductions in PJM's economic demand-side response program (mostly from the real-time rate option) has increased from 50 MWh in 2001 to 48,622 MWh in 2004, for January through September 2004. To put that in perspective, PJM currently has a total annual energy delivery of approximately 700 million MWh. Obviously, the savings from these programs is only a small fraction of the total energy used in PJM.

In a survey of state customer demand-side response programs, PJM identified 7,030 MWs of load that are exposed to real-time prices through tariffs approved by the state commissions in New Jersey and Maryland. An additional 934 MWs are enrolled in independent demand-side response programs. In sum, the PJM, state, and independent demand-side response programs account for 11,562 MWs in the PJM system. Again, for perspective, the PJM peak demand is about 131,330 MWs and has approximately 163,806 MWs of generating capacity.

While the demand-side response programs are growing, they still represent a fraction of the total energy use. The PJM MMU states that:

> [t]he demand side of wholesale electricity markets is severely underdeveloped. This underdevelopment is among the basic reasons for maintaining an offer cap in PJM and in other wholesale power markets. It is widely recognized that wholesale electricity markets will work better when a significant level of potential demand-side response is available in the market. The PJM demand-side program should be understood as one part of a transition to a fully functional demand side for its Energy Market. [p. 86]

This "underdevelopment" of demand-side response programs is not what makes the quantity of electricity demanded by consumers relatively unresponsive to price changes. This unresponsiveness is mostly a function of the underlying demand for the product, which is well known to be very inelastic, especially in the short run. The demand elasticity is a measure of the degree of responsiveness that the quantity demanded changes relative to the price change. Inelastic demand means that for a given change in price, the quantity demanded changes less than proportionally. For example, if the price for electricity increased by 50 percent, but the quantity demanded decreased by only five percent, the reduction in quantity demanded would be less than a proportional decrease. The point is that it is the proportional change that is important, not just the absolute change. The reason for this inelasticity in the demand for electricity is that there are few substitutes that customers can switch to quickly. Over time, however, customers can replace air conditioners, appliances, lights, and other electrical devices with more efficient replacements. But that simply takes time.

The fact that customers cannot respond quickly to price changes gives suppliers some degree of price leverage, given also that there are both highly concentrated markets and significant entry difficulties for alternative suppliers. Again, all three structural characteristics are important in determining a firm's or group of firms' market power.

It would be advantageous to have at least one of these structural characteristics working in favor of competitive market development–and, ideally, at least two would be more beneficial to consumers. Unfortunately, for reasons just explained, the electric supply industry is characterized by highly concentrated markets, entry barriers for alternative suppliers to compete in regional markets, and very unresponsive demand. Recognizing these limitations, ISOs and RTOs must use mitigation procedures in order to attempt to prevent suppliers from taking advantage of any market power they may be able to exercise.

Capacity Credit Markets

Under PJM rules, each load-serving entity (LSE) has the obligation to own or acquire capacity resources equal to the peak load that it serves plus a reserve margin. LSEs are defined as entities that provide electricity to retail customers. LSEs can acquire capacity by buying or building units, by entering into bilateral arrangements with terms determined by the parties, or by participating in the capacity credit markets operated by PJM. The PJM capacity credit markets are designed to balance the supply of and demand for capacity not met through the bilateral market or through self-supply. The capacity credit market participants would include competitive LSEs that need to acquire the capacity resources required to meet their capacity obligations or to sell capacity resources no longer needed to serve load.

In its assessment of the capacity markets, the PJM MMU concludes:

> [g]iven the basic features of market structure in both the PJM and ComEd Capacity Markets, including high levels of concentration, the relatively small number of nonaffiliated LSEs, the capacity-deficiency penalty structure facing LSEs, supplier knowledge of the penalty structure and supplier knowledge of aggregate market demand if not individual LSE demand, the MMU concludes that the likelihood of the exercise of market power is high. These structural conditions are more severe in the ComEd Capacity Market than in the PJM Capacity Market. Market power is endemic to the structure of PJM Capacity Markets. [p. 33]

Structural Issues in the Development of Competitive Electricity Markets

Whether retail customers will see benefits, for example, lower prices and a greater increase in supply and demand options than under cost-based regulation, depends on three structural problems that the industry currently faces.

Market Power

Prices should reflect marginal cost, without significant mark-up, if there is no or only minimal market power, as discussed above. Since markets are highly concentrated, alternative suppliers have limited ability to enter the market and compete with incumbent suppliers and because demand is very inelastic, the possibility of market power being exercised by suppliers is a distinct possibility. The California and western power crisis of 2000 and 2001 had several causes, but supplier market power clearly played a substantial role.

Transmission System Costs

It has generally been assumed that increased generation operating cost efficiencies that may be achieved through competitive pressures and economies of scale in transmission operation would more than offset the costs of operating an ISO or

RTO and other costs incurred to maintain system reliability and integrity. However, the cost of developing and maintaining and the current ISOs and RTOs has increased considerably over time, as noted at the beginning of this report. More than likely, the net increased cost of moving from vertically integrated utilities to an ISO/RTO arrangement will be passed on to retail customers. When the vertical structure of the former utilities ended, responsibility for the functions that were performed by the utility transferred to the ISO or RTO. Whether this new industry arrangement is a net gain or loss is not known at this time, since it is still forming. The extensive blackout of August 2003, while perhaps not caused directly by the restructuring of the industry, does suggest that attention needs to be given to all the functions that the vertical utilities used to perform and the new incentives and responsibilities that competitive suppliers and transmission owners now face.

Price-Setting on the Vertical Segment of the Supply Curve

A third structural problem is the frequency with which the vertical portion of the regional supply curve determines the regional price. These are the peak hours when the demand for electricity increases to a point where the highest priced generation units are needed to operate to meet the demand.[18] Some states (described earlier in this report) are now depending on the wholesale market to secure supply for retail customers and to determine the price for power. In this market, for those hours, the price for power is set by the high cost marginal generation units, typically units that use natural gas. The prices that the consumers in these states are paying exemplify this point – they are no longer paying the *average cost* of power produced by their utilities, but are paying the *marginal cost* of power in the region. Ideally, in an efficient competitive market, this is what is needed to send the correct economic signal to consumers and suppliers to use and supply power efficiently. However, as noted, the power industry is not like most competitive markets. This industry has a long flat supply region that extends over a wide output range, and then turns upward and becomes

[18]This summer is providing a good example of this occurrence, where the price for power has been above $100 frequently on the hot days and occasionally much higher.

nearly vertical as the maximum output is approached. It is that vertical segment of the supply curve that is determining the price at many hours of the year.

The MMU's 2004 State of the Market Report, states that combustion turbine (CT) generation was the marginal unit 22 percent of the time during 2004. This does not include gas-fired combined-cycle generation, which would include most new units added to PJM in recent years and other marginal steam generation units. Even so, this is still nearly 2,000 hours in the year when CT is determining the price and will have an impact the overall wholesale price and eventually, retail customers.

This third structural problem can be addressed through increased generation and transmission capacity and demand response programs (which would help alleviate the first problem too, market power). However, this will take time to develop, and it remains to be seen whether the current incentives will encourage sufficient building of base load capacity. So far, at least, it appears that competitive markets alone do not encourage the building of base load capacity. Suppliers appear to be unwilling to build base load capacity that will have the effect of lowering the price they receive for power. Adding base load units has the effect of lengthening the flat part of the supply curve and reducing the number of hours the upward sloping or vertical segment is determining the price. Given the investment that base load units require, and the impact they would have on the market price, it is not surprising that there is a preference for smaller intermediate and peak-load generation units.

Transmission owners that also own generation are also less likely to be willing to build or upgrade transmission facilities that will only serve to lower the price received for the power sold from the generation facility. Under cost-based regulation, the incentive was to perhaps overbuild capacity since it would contribute to the company's earnings. These incentive issues were dealt with, however clumsily, under cost-based regulation for many years using used-and-useful and prudence standards. However, the incentives in the type of markets developing now are poorly understood and only partially dealt with in the current policy discussions in the industry.

The conventional view is that frequently higher prices (that is, "scarcity" prices) will induce more building of capacity. While it is true that there was a building boom that lasted roughly from about 2000 through 2003, nearly all that capacity was natural gas-fired, and new building activity has dropped off considerably. (This decline in the building of new capacity and the impact that natural gas prices now has on power prices are discussed in last year's Performance Review, pages I-6 through I-9.)

Electric Supply Industry Market Structure: Competitive, Monopoly, or Oligopoly?

In addition to the three structural characteristics of electricity supply and demand described above, there are other features of electricity and market design that may also contribute to suppliers' ability to exercise market power. First, electricity is, by design, homogenous, that is, a kilowatt of power that is delivered on the transmission and distribution system must conform to the standards of the interconnection requirements that all suppliers must follow to be connected to the electric system.[19] From an economic standpoint, that means that it is difficult for a supplier to differentiate its product or for customers to distinguish one product from another. Most customers appear to be indifferent to the type of resources used to generate the power they consume.[20] In general, consumers cannot distinguish one company's kilowatt hours from another. While this makes it easier for customers to evaluate the offers from suppliers, it also makes it difficult for alternative suppliers to separate themselves in the market, for example, by saying they offer more reliable power (customers are typically explicitly told that reliability will not be affected by the choice of supplier they make). As a result, price is the main criteria customers have to evaluate offers they receive. Overall, this is an advantage for incumbent retail suppliers since it usually means that customers are reluctant to switch suppliers unless they see a appreciably lower price

[19]In the electric supply industry, this generally means meeting or exceeding standards for "Good Utility Practice." See for example PJM's Operating Agreement.

[20]For electricity, one important exception is "green" power, that is, power that is produced in part or completely from renewable resources. Some retail customers, when offered the option, choose to pay a higher price to purchase green power rather than that what is offered from conventional fuel sources.

being offered by an alternative supplier.[21] This has been especially true for residential customers.

Since electricity is not economically storable in large quantities, it must be generated when demanded and is consumed nearly instantaneously. Consumers or others acting on their behalf, cannot simply put a large amount of power in storage when the price is low for use later or resell it when the price is higher. If storage were available, it could be used to moderate the price and dampen any supplier market power. Also, because of transmission constraints and other physical limits on sending power over long geographic distances, power may not be available to send to higher priced areas to moderate the price.

Finally, suppliers operating in the RTOs and ISOs have considerable knowledge of rival firms' cost structures. This information can be acquired from public information sources, the supplier's own knowledge of costs, and the fuel type and vintage of generation resources owned by rivals. In addition, suppliers repeatedly interact on an hourly and daily basis in the market. This allows suppliers to gather information on rivals and how they respond in different market conditions. They may not know specifically which supplier bid and at what price, but suppliers can see the price results and the results of their own bidding under various market conditions.

In addition to valuable information gathering, the repeated interaction by the firms can lead to collusive behavior, where they attempt to cooperate with each other in order to raise the price, as seen in California during the 2000-2001 power crisis. The repeated interaction also makes it easier to enforce an agreement to control prices. While direct cooperation and collusion would violate anti-trust laws, "tacit collusion" could form with close interaction that reinforces the mutually beneficial action that will lead to higher profits for all suppliers. For example, an agreement (or even an understanding) to reduce output during peak hours would drive up the price for all

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[21] Customers are likely considering transaction costs from switching, including search costs and weighing the perceived risk of switching to an alternative supplier. Put simply, it is not worth the "hassle" of attempting to find and switch to an alternative unless there is believed to be a clear benefit to make it worth the time, money, and effort required to make a good choice.

market participants.[22] Such agreements (such as cartels) are often difficult to enforce when individual actions cannot be easily monitored and enforcement and retaliation for "cheating" is also difficult. With repeated daily interaction, however, monitoring and enforcement is possible.

Of course, this type of behavior is anti-competitive and completely contrary to the policy goals that were intended when the RTO and ISO structures were being formed. However inadvertently, the federal sanction and approved rules could be what allows enforcement and monitoring of an agreement. The openness of the market that is needed for price transparency for buyers and sellers in the market may have an unintended side effect[23] of allowing price "signaling" for suppliers. The characteristic of concentrated electricity markets and that often a relatively small number of suppliers are operating in an area, increases the potential for collusive behavior.

The higher profit from firms' exercising market power should attract other firms and drive down the price. But due to the entry difficulties, this will take time and even be discouraged by the existing suppliers not allowing the price to exceed an entry point for new suppliers to profitably enter the market. Potential entrants, knowing that there could be a price drop if they do enter, may decide not to enter or expand in a market even when the current conditions are favorable. Even if no reaction from incumbent suppliers is anticipated, the additional supply capacity itself from the new entrant may reduce the price below a profitable point. This may be especially true for potential expansion of base load capacity.

[22]Availability of a single "swing producer" would make an agreement easier, that is, a single generation owner that represents a large share of the market, where there is limited generation and transmission availability from the outside that could enter the area. Other generators would benefits from the dominate firm's actions without reducing output (or economically withholding) themselves.

[23]Unintended on the part of policy makers, who are understandably concerned about providing price transparency. Suppliers, on the hand, may easily see the advantages of transparency.

All these characteristics and features taken together[24] suggest that the market structure that is emerging is certainly not perfectly competitive, an impossible standard for any market to reach, nor could the structure be characterized as a pure monopoly, that is, one supplier – although that may occur in some local areas or subregions of an RTO or ISO where one supplier generates nearly all the power and transmission constraints limit outside supply options. Rather, the structure that is suggested is one of an oligopoly, defined as a market where there are a few firms supplying all or most of the output. There are a number of specific oligopoly models that are used to examine industry structure. These models are complex and usually are expressed in mathematical form.[25]

As a practical matter, the question becomes, are customers better off under the developing oligopoly structure or under the previous regulated monopolies structure? Both structures are economically inefficient and not ideal and both lead to consumer prices above marginal cost. One way to do the comparison would be to, on one side of the equation, consider the inefficiencies under regulation, including over capitalization costs, operational inefficiencies, regulatory compliance costs, and resource allocation inefficiencies. Then on the one side of the equation, compare this to the inefficiencies of oligopoly or market power, the higher cost from the loss of vertical economies, the RTO or ISO formation and operation costs, the higher cost of capital for investment in a competitive market, possible under capitalization costs (from increased reliance on intermediate and peak capacity rather than base load capacity), and any additional

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[24]These include, as discussed, a relatively small number of suppliers in a region or subregion, significant barriers to entry for other suppliers, inelastic market demand, a homogenous product, supplier knowledge of rival firms' cost structure, repeated hourly and daily interaction by the firms in the market.

[25]Some example of where models have been applied to the electric supply industry are Benjamin F. Hobbs and Fieke A. M. Rijkers, Strategic Generation With Conjectured Transmission Price Responses in a Mixed Transmission Pricing System – Part I: Formulation," IEEE Transactions On Power Systems, Vol. 19, No. 2, May 2004 and Yan Sun and Thomas J. Overbye, "Market Power Potential Examination for Electricity Markets Using Perturbation Analysis in Linear Programming OPF Context," Proceedings of the 38th Hawaii International Conference on System Sciences - 2005, 0-7695-2268-8/05, IEEE, 2005.

distribution or transmission costs (balanced against any greater scale economies in transmission from a large regional system).

Needless to say, this would require a massive effort to account for all these factors and would require a great deal of judgement to place a valuation on each of these factors. In effect, however, there is an experiment going on right now in the U.S., where parts of the country are developing RTOs and ISOs and others are not, and some states have retail access and others do not.

Wholesale Price Mitigation

Many ISOs and RTOs have an overall price cap or upper price limit, for example, $1,000 per MWh limit on the prices offered. Some also use triggers or thresholds that limit the amount prices can change in a given period of time. For example, the New York ISO uses a reference value, where if a bid is above the reference value by $100 per MWh or is 300 percent greater and the bid causes the price to rise by $100 per MWh or increase by 200 percent, then the bid is replaced with the reference value. PJM uses offer price caps in local areas that are judged to be "structurally noncompetitive." In these cases, the offers would set the price above competitive levels, without price mitigation. The capped units receive the higher of the market price or their offer price cap. The offer price cap is calculated based on the incremental operating cost of the generation resource, plus ten percent.

The PJM rules designed to limit market power that could be exercised include the $1,000 per MWh offer cap in the PJM energy market and offer capping of units owned by those that have the ability to exercise local market power. The PJM MMU notes that "[n]o evidence suggests that market power was exercised in these areas during 2004, primarily because of generation owners' obligations to serve load and PJM rules limiting the exercise of local market power. If those obligations were to change, however, the market power-related incentives would change as a result."[26]

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[26]PJM MMU, 2004 State of the Market Report, p. 53. Another analysis that notes the importance of the load obligations in curbing market power is James Bushnell, Erin T. Mansur, and Celeste Saravia, "Market Structure and Competition: A Cross-Market Analysis of U.S. Electricity Deregulation," March 2004.

PJM MMU states that PJM "rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation."[27]

PJM and other RTOs and ISOs also try to limit market power through market design and structural changes. Where and when market power exists, the rules to limit market power are designed to mitigate it. The structure and design changes are intended to limit the ability to exercise market power over time. The MMU states, "[m]arket design itself is the primary means of achieving and promoting competitive outcomes in the PJM Markets. One of the MMU's primary goals is to identify actual or potential market design flaws. PJM's market power mitigation goals have focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where market structure is not competitive and thus where market design alone cannot mitigate market power."[28]

PJM defines the "offer price cap" as "[t]he weighted average Locational Marginal Price at the generation bus"[29] or "[t]he incremental operating cost of the generation resources as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals, plus 10% of such costs" or "[f]or a unit that is offer capped for 80 percent or more of its run hours, the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals, plus the higher of $40 per megawatt-hour or the unit-specific going forward costs of the affected unit" or "[a]n amount determined by agreement between the Office of the Interconnection and the Market Seller."[30]

When applied on a cost basis, the offer cap is based on the "incremental operating cost of the generation resource as determined in accordance with Schedule 2

[27]PJM MMU, 2004 State of the Market Report, 63.

[28]PJM MMU, 2004 State of the Market Report, p. 45, footnote omitted.

[29]Sheet No. 131A, PJM Operating Agreement.

[30]Sheet No. 132, PJM Operating Agreement.

of the Operating Agreement and the PJM Manuals, plus 10% of such costs."[31] The components of the Schedule 2,[32] appear to be reasonable, but have an "other incremental operating cost" component. In addition, the cost components are self-reported. This may cause an expansive definition of incremental cost and could create a "moral hazard" problem in reporting. It is not clear what analysis, if any, has been done to verify or audit the calculation of incremental cost that is reported by an independent verification of these costs. Under current PJM rules, units are also exempted from being offer capped based on when they were constructed and unit location.[33]

The MMU also calculates a "price-cost markup index"[34] that is intended to "estimate the difference between the observed market price and the competitive market price."[35] The markup index estimates the percentage of the price that is markup above marginal cost. The average markup index in 2004 was 3.4 percent, with a maximum of six percent and minimum of zero. Since the markup is based on the marginal cost estimate that includes the 10 percent adder, mentioned above, the MMU also calculates an adjusted markup index that takes out the 10 percent adder. The average adjusted index was 8.4 percent (that is, 8.4 percent of the price is markup above the adjusted marginal cost), with a maximum of 12.3 percent and minimum of 4.7 percent. Both the unadjusted and adjusted indices are relatively modest. However, it assumes that the marginal cost estimates are accurate (which, as noted, may be overstated) and averages the markup values over many units at various times and locations. This method of calculation could understate that actual markup considerably.

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[31]Operating Agreement, 6.4.2 (a) (ii), Sheet No. 132.

[32]"Components of Cost," PJM Operating Agreement, Sheet No. 167.

[33]PJM Operating Agreement, section 6.5, "Exempt Generation Resources."

[34]MMU, 2004 State of the Market Report, at page 67 through 69. Past years' markup calculations by the PJM MMU have been reported in pervious Market Performance Reviews.

[35]MMU, at page 67.

Offer capping is not used very often in PJM. According to PJM's MMU, in 2004, only 1.3 percent of total run hours were offer-capped in PJM. The offer-capped hours per MW has decreased since 2001 because fewer areas are deemed to be "structurally noncompetitive." Also, since the rules allow the capped units to receive the higher of the market price or their offer price cap and the cap is calculated based on the incremental operating cost of the generation resource–plus ten percent, little protection for the consumer may actually be provided. The MMU notes that

> offer capping does not result in financial harm to the affected units. Detailed analysis of actual net revenues for 2003 showed that frequently offer-capped units received net revenues that were close to those received by units not offer-capped or that were offer-capped, but for significantly fewer hours. In fact, offer capping can, at times, result in higher revenues for offer-capped units than for other comparable units because the offer-capped units operate when market conditions result in comparable units not operating.

The test is not whether "financial harm" is being caused, but whether the market mitigation measures actually limit all opportunities for suppliers to exercise significant market power. It appears that has not been properly studied in PJM.

A Closing Perspective: What We Have Learned So Far

Most observers of electric industry restructuring would agree that it has been more difficult and more complex than believed when the process began in the 1990s.[36] Because of the technical nature of electric supply and the many functions that remain regulated, the task was likely to be difficult. Difficulty and complexity are not problems in themselves, but it could lead to unintended consequences that designers could not

[36]"The" beginning would be hard to pinpoint exactly since PURPA power generation and wholesale competition began to become significant in the 1980s. However, a reasonable beginning of the current restructuring efforts could, on the wholesale side, be said to start with passage of the Energy Policy Act of 1992 and, on the retail side, with states beginning to pass legislation to allow retail access in 1996.

have anticipated. No one designed the current RTO structure, it evolved through a series of FERC orders, responses by the RTO's themselves, and the clash of interest groups in the FERC proceedings. Of course, where the industry began was also very influential, that is, the generation, distribution, and transmission infrastructure that was built over decades and the industry-specific events that preceded restructuring.[37]

Two significant recent events have occurred that will likely have a material impact on the development of wholesale markets across the country. First, FERC approved the Exelon merger with PSEG, without a hearing.[38] In the Order approving the merger, FERC states that,

> We are not convinced by arguments that Applicants should have analyzed the merger's effect on their ability and incentive to harm competition by engaging in strategic bidding (which is a form of unilateral market power). The Commission's analysis focuses on a merger's effect on competitive conditions in the market. That is, we look at the merger's effect on the concentration of the relevant markets, as measured by the HHI. Protestors argue that the HHI solely looks for the possibility of the coordinated exercise of market power and misses the possibility of the unilateral exercise of market power. They say that Applicants have not shown that the merger will not increase the likelihood of the merged firm exercising unilateral market power. We reject this argument for two reasons. First, the Merger Guidelines recognize that the HHI does, in fact, convey information about the likelihood of the unilateral exercise of market power. [Footnote 94 is: Section 2.0 of the Merger Guidelines.] Second, in order to address the screen failures in various season/load conditions, Applicants have proposed divesting units with a range of operational and cost characteristics, including the types of units that protestors argue could be used to engage in strategic bidding or withholding in order to exercise unilateral market power. Furthermore, such strategic bidding or withholding could

[37]This list would be long indeed, including the 1965 northeast blackout and its affect of industry reliability standards, the energy crisis of the 1970s that led to the passage of PURPA, the Three Mile Island accident and the nuclear power plant cost over runs, to name a few.

[38]Federal Energy Regulatory Commission, Docket No. EC05-43-000, issued July 1, 2005.

> qualify as market manipulation under the Market Behavioral Rule #2 [footnote 95 is: Market Behavior Rules, 105 FERC ¶ 61,218 (2003) Order on Reh'g, 107 FERC ¶ 61,175 (2004) Rule # 2.E "bidding the output of or misrepresenting the operational capabilities of generation facilities in a manner which raises market prices by withholding available supply from the market."] and result in, among other things, revocation of market-based rate authority.[39]

On FERC's first point, they correctly characterize the point of the section on the significance of market concentration, but missed a very important caveat clearly stated in the Merger Guidelines' section they cite. The Merger Guidelines state in Section 2.0,

> Other things being equal, market concentration affects the likelihood that one firm, or a small group of firms, could successfully exercise market power. The smaller the percentage of total supply that a firm controls, the more severely it must restrict its own output in order to produce a given price increase, and the less likely it is that an output restriction will be profitable. If collective action is necessary for the exercise of market power, as the number of firms necessary to control a given percentage of total supply decreases, the difficulties and costs of reaching and enforcing an understanding with respect to the control of that supply might be reduced. *However, market share and concentration data provide only the starting point for analyzing the competitive impact of a merger.* Before determining whether to challenge a merger, the Agency also will assess the other market factors that pertain to competitive effects, as well as entry, efficiencies and failure [emphasis added].[40]

As noted earlier, market concentration is important in determining the ability of a firm to exercise market power, but it is a screening tool that does not provide a definitive test for market power. Further analysis is needed if the concentration levels are high. Market concentration measures are not a substitute for the further analysis. As an example of the type of analysis that FERC and states should conduct is in the very next

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[39]FERC, Docket No. EC05-43-000, pp. 44 and 45 (footnotes included).

[40]U.S. Department of Justice and the Federal Trade Commission, "Horizontal Merger Guidelines," Section 2.0, issued April 2, 1992, revised April 8, 1997, p. 18.

section of the DOJ Merger Guidelines, "Lessening of Competition Through Coordinated Interaction," where it states,

> A merger may diminish competition by enabling the firms selling in the relevant market more likely, more successfully, or more completely to engage in coordinated interaction that harms consumers. Coordinated interaction is comprised of actions by a group of firms that are profitable for each of them only as a result of the accommodating reactions of the others. This behavior includes tacit or express collusion, and may or may not be lawful in and of itself.[41]

As noted also, coordinated interaction and collusion could have particular relevance for electricity markets, given the nearly continuous interaction that firms have in RTO and ISO markets. A merger of firms of any size within the same RTO means fewer firms in the market and makes coordination more possible. In its analysis of the Exelon/PSEG merger, FERC did not examine the possibility of collusion of any sort. Also, the ISO and RTO market monitors do not examine this possibility either.

On FERC's second response to protestors (from the above quote) that argued that there could be strategic bidding or withholding to exercise unilateral market power, FERC notes that such strategic bidding or withholding *could* (their word) qualify as market manipulation under the Market Behavioral Rule #2 ("bidding the output of or misrepresenting the operational capabilities of generation facilities in a manner which raises market prices by withholding available supply from the market") and would result in revocation of market-based rate authority, among other things. This depends, of course, on FERC's ability to detect such activity, which would be difficult given the considerable amount of data to examine. FERC has its own market monitor, the Office of Market Oversight and Investigations (OMOI), but it tends to focus on descriptive analysis and covers the entire country and other energy markets as well. They do not produce detailed analyses of the markets for the public to examine.[42] FERC would have

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[41]"Horizontal Merger Guidelines," Section 2.1, p. 18.

[42]The OMOI does investigate specific market events. Two example are the Office's analysis of the Western power crisis and the New England January 2004 "Cold Snap." However, these are after-the-fact reviews of past events and are mostly

to conduct the investigation or have a means to detect possible collusive actions.[43] FERC does not even appear to be currently aware of the possibility.

Clearly, strategic bidding and withholding are issues that need to be examined. As noted, there are academic papers that suggest that strategic bidding could happen and how it could (and perhaps actually does) happen in LMP markets.[44] While academics have been studying this issue for a few years, it is not purely an academic exercise. There have been various seminars on how to bid in LMP markets, with titles such as, “Formulating Bidding Strategies for GENCO Assets in LMP Markets” and another with the title “Using Shadow Settlement as a Strategic Tool To Improve Bottomline Profits in LMP Markets.” The first seminar promises attendees are that they will learn the answer the question “How can you formulate bidding strategies that maximize your expected profits from both the day-ahead and real-time markets?” Another seminar objective is (and perhaps more worrying) “How should you formulate bidding strategies to reflect market mitigation rules?” The second seminar has as an objective to show attendees “How can you use shadow settlement as a strategic tool to provide feedback to traders on bidding strategies?”

Of course, it should be expected that generation owners should learn the ISO and RTO rules and seek to make a profit in the process. That is the point of having a competitive market, that is, using the profit motive to drive cost-minimizing and profit-

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descriptive in nature. This is helpful to understanding the event, but not a substitute for more detailed analysis of the event or for analysis of the markets in general.

[43]FERC’s state of the markets report notes that in February 2005 two Texas retail providers have sued several electricity suppliers alleging price fixing and collusion. Federal Energy Regulatory Commission, Office of Market Oversight and Investigations, “2004 State of the Markets Report,” June 2005, p. 131.

[44]Some example, that have further citations, are Benjamin F. Hobbs and Fieke A. M. Rijkers, Strategic Generation With Conjectured Transmission Price Responses in a Mixed Transmission Pricing System – Part I: Formulation,” IEEE Transactions On Power Systems, Vol. 19, No. 2, May 2004 and Yan Sun and Thomas J. Overbye, “Market Power Potential Examination for Electricity Markets Using Perturbation Analysis in Linear Programming OPF Context,” Proceedings of the 38th Hawaii International Conference on System Sciences - 2005, 0-7695-2268-8/05, IEEE, 2005. These papers were both provided as part of the response to first set of ComEd Data Request.

maximizing behavior that leads, hopefully, to a competitive market outcome. From a public policy standpoint, however, it is important to ensure that it really is a competitive outcome, and not something that has the appearance of a market, that is, with buyers and sellers and high volume, but where suppliers are earning economic profit and imposing additional costs on society. Besides studies of California during the 2000-2001 crisis period, no analysis has been done that studies actual bidding behavior in an ISO or RTO market. However, the academic discussion and what bidders could or may be able to do in these markets, suggests that, at the very least, the issue of strategic bidding needs to be studied. As another academic paper warns, "[g]iven the cost of mistakes, e.g., the California electricity market in 2000, a more than incremental change in a market design requires careful analysis, especially of how the participants can outwit the designers."[45]

The second significant recent event that will likely have a considerable impact on the development of wholesale markets is the passage of the Energy Policy Act of 2005. While the legislation is far reaching and is covers many areas of energy policy, of particular interest in the context of electric market competitiveness is Subtitle F of the Act, "Repeal of PUHCA" (the Public Utility Holding Company Act of 1935) and Section 1289 "Merger Review Reform."[46] The repeal of PUHCA is straight forward enough, some aspects of federal and state commission access and other provisions were replaced, but the PUHCA requirements on utilities are repealed. The impact of the Merger Review section will depend on FERC's implementation and a full analysis of both sections of the legislation is beyond what can be done at this time. However, most observers seem to agree that this will almost certainly lead to more and larger mergers and perhaps involve oil, natural gas, electric, and other combination companies. This

[45]Lester Lave, Sarosh Talukdar, Kong-Wei Lye, Eswaran Subrahmanian, "Designing Electricity Markets: Are Freshmen or Wind Tunnels More Useful?" Carnegie Mellon University, December 20, 2004. Presented at the Annual Meeting of the American Economic Association, panel on "Lessons from Electricity Deregulation," Philadelphia, PA, January 2005.

[46]Actual repeal of the PUHCA is in section 1263, "Repeal of the Public Utility Holding Company Act of 1935." From the House of Representatives and Senate Conference Report.

will likely mean even greater concentration of the industry, and in particular, increased concentration of ownership of generation resources. If the result is an increase in the concentration of generation ownership, then, as economic theory suggests, the result will be less competitive wholesale electricity markets.

Proponents of the current market structure point out that the RTO system that is currently operating uses a regional, security constrained economic dispatch that combines many of the old original utility control areas into one regional centralized system. The RTO manages congestion using LMP, does real-time balancing of the system, coordinates and keeps the power flows within technical limits (maintaining voltage and frequency), and in general, controls the regional grid operations. The RTO also manages several other markets, such as the day-ahead market and the allocation and auction for FTRs. These markets are, in the proponents view, sufficiently transparent for buyers and sellers to operate efficiently. The advantage to the regional approach is that the generation and transmission resource base is much larger than any one utility used to have and this means lower cost economic dispatch and better regional control of the transmission system. A combination of the size, structure, and the RTOs rules keeps the flow of power in a least-cost, system-wide dispatch. The market imposes a competitively-driven discipline that keeps market power in check. Monitoring and mitigation procedures are all that is needed to check any market power that may arise. Forward markets and hedging instruments are also available to manage risk and to facilitate trading.

Broader dispatching will lead to lower operating costs systemwide than what would occur with separate utility control areas. But this does not lead automatically to the lowest price for consumers. The degree of competition and the market structure will determine that. Also, thus far, PJM has been able to operate the system reliably, despite facing considerable challenges this summer, but there are concerns about how to encourage the building of base load capacity and new transmission in the future.

While it is true that, in general, competition preforms better than regulation to achieve economic efficiency, in many markets it does not always hold true. An unregulated monopoly or oligopoly could lead to the same level or a worse level of inefficiencies as rate-of-return regulation. The inefficiencies would be in different forms, that is, regulated firms generally would have less incentive to operate their plants as efficiently as a competitive firm would. A monopolist, conversely, would have an incentive to operate cost efficiently but would charge a higher price than a competitive firm and would reduce output to less than what a competitive firm would produce. Oligopoly is a market structure that would fall somewhere in between monopoly and competitive firm in terms of charging a higher price and reducing output but would perhaps operate more efficiently than a regulated firm. The overall impact is what matters from a public interest perspective.

There is an apparent assumption that because ISOs and RTOs are operating markets and maintaining system reliability and that markets are active and have forward markets present, that this implies these markets are competitive. This is confusing market activity with degree of competitiveness. This implicit assumption that competition must always be better, *a priori*, forgets that competition is a means to an end, not an end in itself.

Also, it should be remembered that, as inefficient as it may have been in terms of encouraging cost efficiencies, most of the assets that are currently in RTOs were built during a time of traditional regulation. In fact, a common criticism of rate-of-return regulation was that it led to an *over* investment in capital and infrastructure. The industry is now talking about very un-free market-like incentives to encourage investment in base load generation and transmission–including some that are in the just passed Energy Policy Act of 2005. It is not certain at this time how much electricity customers and taxpayers will have to pay in additional incentives and subsidies to achieve the desired level of investment or how we will determine that level.

It is not known with any degree of certainty if there is significant market power in PJM or other ISO and RTO markets. The analysis conducted so far of the ISOs and RTOs themselves is insufficiently detailed enough to warrant a conclusion one way or the other. For example, the Market Monitoring Unit does a good job providing detailed descriptions of the PJM markets, however, more detailed analysis of the markets needs to be conducted. For the reasons described, the conditions are such that is it possible that considerable market power could be exercised. Only an independent analysis will help shed some light on the issue.

An independent analysis of the wholesale market and its potential impact needs to be conducted in a comprehensive and rigorous manner by someone independent of the RTO and with the analytical capabilities and data access to do so. This is needed to characterize the condition of regional wholesale markets and determine the likely outcome of the regional markets on retail prices. This study needs to be a structural analysis to determine whether there is in fact a sufficient level of competition among suppliers or, as discussed, they are operating closer to an oligopoly structure with tacit or other forms of collusion. This analysis needs to be independent of the ISOs and RTOs so that it is not influenced by any single or group of market participants that obviously would have an interest in the outcome of the analysis.

This type of analysis is impossible without access to detailed price and bidding data. Unfortunately, data restrictions limit access to external analysis. Either states or FERC or other federal agencies, need to mandate such a study to allow the required data access. Until this is done we are “flying blind” and operating on the assumption that we have sufficient altitude and that there are no mountain ranges in front of us.

State transition periods have been ending and many of these states, as discussed, are seeing significant price increases. In these cases, customers are seeing the full impact of the wholesale market, including the fuel price increases. Fuel costs have increased across the country, but not all states have seen price increases of size that was summarized earlier in this report, as the EIA data show. For example, coal prices have increased, but West Virginia, a non-restructured state (and in PJM) which produces about 90 percent of its electricity with coal, has had flat retail prices. The reason is that most utilities either have their own coal resources, have long term contracts with coal suppliers, or some combination of their own resources and contracts, so the full impact of a change in fuel prices does not fully impact customers in these cases.

There is not a general one-to-one correlation between rising fuel costs and retail rates, therefore, it cannot be determined how much is attributed to increased fuel costs and what is attributed to other costs, without examining each company or contract for type of fuel used and proportion of each. According to EIA figures, the national average retail price for all sectors from 2004 through April 2005 increased by 3.6 percent. This suggests that, nationally, the full impact of fuel cost increases is not being passed through in rates. Again, this is likely because utilities and other suppliers often have long term contracts for the supply of coal, natural gas and other fuels, have access to their own fuel supply or some combination of both and also have different fuel use mixes. In the case of regulated utilities, fuel cost increases would be passed through fuel adjustment mechanisms, but in proportion to the fuel used. In the case of retail customers in restructured states where the transition period has ended and their price is now determined in the wholesale market, the customers are now taking the brunt of the impact that increased fuel prices is having on wholesale prices, a point that can be seen in the EIA data plotted in this report.

It appears from the data so far, that most retail customers (especially residential) in restructured states where the transition period has ended and the price is now based on the wholesale market are seeing prices increase faster that in the non-restructured states or states still in transition with a price cap. At best, at this point in time, no discernable overall benefit can be seen from restructuring.

PART II

STATUS OF RETAIL ACCESS AND COMPETITION

IN THE COMMONWEALTH

INTRODUCTION

In this part of the SCC's report to the Governor and to the Commission on Electric Utility Restructuring ("CEUR"), we provide an update regarding activities in Virginia related to competition in the electricity market. Since § 56-596 of the Restructuring Act[1] directs us to file a report each September 1st, the section on the status of competition in the Commonwealth will provide a history of the transition to competition. Each year we will prepare a chronology and summary to detail the progress of competition and activities of interest during the past twelve months.

During the past year this Commission has continued with the scheduled implementation of the Restructuring Act. Currently, the vast majority of the Commonwealth's 3.2 million electricity customers have the right to choose an alternative supplier of electricity. In compliance with the Act, all electricity customers of Virginia's investor-owned utilities and electric cooperatives are eligible to switch to a competitive supplier except for about 29,800 customers in the southwestern part of the Commonwealth[2] and approximately 7,700 customers served by Powell Valley Electric Cooperative.

As discussed later in this report, work continued during the past year to address restructuring issues such as those related to default service, market-based costs, and RTOs, to name a few. Virginia finds itself in a similar situation as last year in that there have not been any new competitive offers to provide electricity supply. Similarly to other states that offer retail access, competitive activity remains stagnant in Virginia. One supplier continues to serve

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[1] Virginia Electric Utility Restructuring Act, Chapter 23 (§ 56-576 et seq.) of Title 56 of the Code of Virginia.

[2] Amending legislation passed by the 2003 Session of the General Assembly as House Bill 2637 to § 56-580 of the Code of Virginia, suspended application of the Restructuring Act to Kentucky Utilities operating in the Commonwealth as Old Dominion Power Company until such time as the utility provides retail electric services in any other service territory in any jurisdiction to customers who have the right to receive competitive retail electric energy.

a small portion of customers in northern Virginia with a limited renewable resource, but no other electricity supply offers have been made.

Despite modifications to the Commission approved pilot programs of Dominion Virginia Power ("Dominion" or "DVP") as a means to encourage competitive activity, there has been no activity other than the licensing of a few more competitive service providers ("CSPs"). Likewise, Commission approval of Dominion's and American Electric Power's ("AEP" or "APCo")[3] integration into PJM has not yet spurred any competitive activity. Further details will be discussed later in this report.

The Commission continues to implement the Restructuring Act. The following pages provide an overview of the continued transition to full retail access and updated information regarding a diverse list of activities and investigations devoted to the development of a competitive market.

[3] Doing business in Virginia as Appalachian Power Company, "Appalachian Power" or "APCo".

ACTIVITY RELATED TO RETAIL ACCESS

This section provides a review of activity during the past 12 months to further develop retail access in Virginia. In addition to supplying details on the number of customers who switched energy providers, there will also be discussions of the licensing of suppliers and aggregators and marketing activity.

Full Retail Access

Full retail access was available to practically all Virginia electric consumers on January 1, 2004. Allegheny Power ("AP")[4], APCo and Delmarva Power & Light ("Delmarva") implemented full customer choice within their respective Virginia service territories on January 1, 2002. To date, no CSP has registered with AP or APCo to provide service within their respective Virginia service territories. Only one CSP is fully registered with Delmarva but has not pursued serving customers.

Dominion's service area was fully opened to retail choice on January 1, 2003. To date, six CSPs and aggregators are registered with DVP to provide service within its Virginia territory. Only one CSP, Pepco Energy Services ("PES"), is currently serving customers. PES withdrew its offer in May 2003, but continues to serve about 1,600 customers. Although PES is not currently mass-marketing its service, it will accept enrollments for new customers to replace slots that become available as customers drop PES to return to DVP's capped rates. To date, all CSPs that have served customers in DVP's territory have been affiliates of an electric or natural gas utility.

[4] Doing business in Virginia as the Potomac Edison Company ("PE").

All of the electric distribution cooperatives,[5] complied with the Commission's Order in Case PUE-2000-00740 and implemented retail access in each of their respective territories by January 1, 2004. To date, there has been no competitive activity among the Cooperatives except for a small number of CSP inquiries regarding Rappahannock and Northern Virginia Electric Cooperatives.

Suppliers/Aggregators

The Commission is responsible under §§ 56-587 and 56-588 for licensing suppliers and aggregators interested in participating in the retail access programs in Virginia. The Staff has established a streamlined mechanism for processing license applications. To facilitate the prompt processing of license requests, the SCC website provides access to the licensing requirements.[6] Staff has an internal deadline of 45 days from the receipt of a complete application to the issuance of a license. Thus far, that deadline has been met for all applications. Currently, twenty-eight electric and natural gas CSPs and aggregators are licensed by the Commission to participate in full retail access. A list of licensed suppliers can be found at the end of this section.

In order to participate in an LDC's retail choice program, a CSP must also complete a registration process with the utility. Electronic Data Interchange ("EDI")[7] testing between the CSP and the utility is required as part of the registration process. The testing must be completed before a supplier can begin enrolling customers.

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[5] A&N Electric Cooperative, BARC Electric Cooperative, Central Virginia Electric Cooperative, Community Electric Cooperative, Craig-Botetourt Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Inc., Northern Virginia Electric Cooperative, Prince George Electric Cooperative, Rappahannock Electric Cooperative, Shenandoah Valley Electric Cooperative, and Southside Electric Cooperative, Inc., collectively the "Cooperatives".

[6] Guidelines to become licensed as a competitive service provider or aggregator are available on the SCC's website at: http://www.vaenergychoice.org/suppliers/licensesteps.asp .

[7] EDI standards and guidelines are established by the Virginia Electronic Data Transfer Working Group ("VAEDT"). Further information may be found at http://www.vaedt.org .

Currently, six CSPs, Dominion Retail, Pepco Energy Services, Washington Gas Energy Services, Commerce Energy, ECONnergy Energy Company and WPS Energy Services are fully registered with DVP. Additionally, six aggregators, Advantage Energy, American PowerNet Management, Buckeye Energy Brokers, EnergyWindow, WPS Energy Services and Independent Energy Consultants are fully registered with DVP.

WGES is fully registered with Delmarva and Old Mill Power has completed EDI testing but not yet completed its registration with Delmarva.

Licensed Competitive Service Provider/Aggregator
as of August 5, 2005

Company Name	**Customer Class(es)**	**LDC Service Territories in which CSP registered**	**Services Provided**
Pepco Energy Services	R, C, I	DVP, WG, SG, CGV	Natural gas, electric and aggregation (E&G)
Dominion Retail, Inc.	R, C,I	DVP, WG	Natural gas, electric and aggregation (E&G)
Washington Gas Energy Svcs	R, C, I	DPL, DVP WG, SG, CGV	Electric & natural gas
EnergyWindow, Inc.	R, C, I	DVP	Aggregation (E&G)
Advantage Energy	R, C, I	DVP	Aggregation (E&G)
Amerada Hess Corporation	C, I	WG, SG	Electric, natural gas and aggregation (E&G)
Energy Svcs Mgmt Va LLC, d/b/a Virginia Energy Consortium	C		Aggregation (E)
Bollinger Energy Corporation	C, I	WG, CGV	Natural gas
Tiger Natural Gas, Inc.	R, C, I	WG, SG, CGV	Natural gas
NOVEC Energy Solutions, Inc		WG, SG, CGV	Electric, natural gas and aggregation (E&G)
Utility Resource Solutions, LP			Natural gas
Old Mill Power Company	R, C, I	DVP (pending), DPL (pending)	Electric, natural gas and aggregation (E&G)
Metromedia Energy, Inc.	C, I	WG	Natural gas
Stand Energy Corporation	C, I		Natural gas
ACN Energy, Inc.	R	WG	Natural gas
AOBA Alliance, Inc.	C		Aggregation (E&G)
UGI Energy Services, Inc.	C, I		Natural gas
Constellation NewEnergy, Inc.	C,I	DVP (pending), WG, SG	Electric, natural gas and aggregation (E&G)
Select Energy, Inc.	C,I		Electric and natural gas
American PowerNet Management, LP	C,I	DVP	Aggregation (E&G)
JP Communications Group	R,C		Aggregation (E)
Buckeye Energy Brokers, Inc.	R,C,I	DVP	Aggregation (E &G)
ECONnergy Energy Co., Inc.	R,C	DVP	Natural Gas
Independent Energy Consultants, Inc.	R,C,I	DVP	Aggregation (E &G)
WPS Energy Services	R,C, I	DVP	Electric and aggregation (E)
Commerce Energy	R,C,I	DVP	Electric
Delta Energy LLC	C,I		Natural gas and aggregation (G)
Renaissance Energy, LLC	C,I		Electric and natural gas aggregation

Customer Type: "R" residential; "C" commercial; "I" industrial

LDC Service Territories:

AEP-VA = AEP Virginia
AP = Allegheny Power
DVP = Dominion Virginia Power
DPL = Delmarva Power & Light
CGV = Columbia Gas of VA
WG = Washington Gas
SG = Shenandoah Gas (division of WG)

Marketing

The only marketing activity that has taken place in any electricity retail access program is in DVP's service territory. Pepco Energy Services continues to provide "green power" to residential customers in Northern Virginia. The renewable generation source is biomass, consisting of landfill gas from a source in central Virginia. The offer consists of 51% renewable energy offered at a premium above DVP's price-to-compare.

Since full retail access began, PES's renewable energy offer is the only offer residential electricity customers have received. To date, about 1,600 residential and 20 commercial customers are enrolled with PES. No industrial customer has yet chosen a competitive electricity service provider.

Customer Participation

Pepco Energy Services began serving retail access customers in January 2002 and is currently the only active CSP. Out of approximately 3.2 million customers in Virginia who currently have the right to choose an alternative supplier of electric energy, about 1,600 customers are currently doing so, or less than 0.1%.

The following table provides the number of electricity customers in the Virginia LDC territories that are currently eligible to shop for a CSP and how many are enrolled with a CSP as of July 12, 2005.

Company	# of Eligible Residential Customers*	# of Eligible Nonresidential Customers*	# of Residential Customers Currently Served By a CSP	# of Non-Residential Customers Currently Served By a CSP
DVP	1,901,785	227,581	1,604	20
AEP-VA	426,723	69,257	0	0
AP	78,584	14,186	0	0
DPL	18,320	3,169	0	0
NOVEC	112,245	7,660	0	0
REC	82,344	4,415	0	0
SVEC	27,861	4,686	0	0
CEC	8,357	1,578	0	0
A&N	10,133	786	0	0
BARC	11,310	580	0	0
CVEC	28,103	2,772	0	0
CBEC	5,684	556	0	0
MEC	28,461	1,707	0	0
NNEC	15,791	956	0	0
PGEC	8,935	1,01	0	0
SSEC	47,730	2,134	0	0
TOTAL	2,818,887	344,218	1,604	20

* Customer numbers as of December 31, 2004

FUNCTIONAL UNBUNDLING AND WIRES CHARGES

This section of the report will describe the steps involved with setting the price for energy while rate caps are in effect. Unbundled generation rates and market prices for generation are essential components to determine wires charges. Additionally, the generation market prices established by the Commission for each incumbent utility help competitive suppliers determine whether they can or will make competitive offers in utilities' service territories.[8]

The first step is the functional unbundling of rates into separate generation, transmission and distribution components as required under § 56-590 of the Restructuring Act. The next step is the calculation of the market price for generation which, when compared to the unbundled generation rate, will determine the amount of an appropriate wires charge, if any. The procedures for calculating market prices and wires charges are detailed in § 56-583 of the Act. A final important component of the pricing of energy is the determination of the price-to-compare for each incumbent electric utility. This benchmark price can then be used by consumers for comparison shopping.

<u>Functional Unbundling</u>

Section 56-590 of the Restructuring Act required Virginia's incumbent electric utilities to file plans detailing the proposed separation of the incumbents' generation, retail transmission and distribution functions. The cases provided the companies an opportunity to file proposed retail access tariffs applicable to customers and third party suppliers. As part of these cases, the Commission also "unbundled" the companies' retail rates for purposes of establishing wires charges.

[8] It should be noted, however, that if a utility's unbundled generation rate is *less* than the Commission-determined market price for generation, then the price a CSP must "beat" in order to make a competitive offer would be the unbundled generation rate, and not the market price.

Rate unbundling in these cases consisted of separating the utilities' bundled rates,[9] for retail electricity service into separate components to reflect distribution, transmission and generation charges. Transmission charges were also unbundled into base and ancillary services. The companies' retail access tariffs addressed and defined the operational relationship between the utilities and competitive service providers in the provision of competitive generation service within the incumbents' respective service territories. These tariffs, among other things, addressed CSP creditworthiness requirements, noncompliance and default, load forecasting and scheduling procedures, and CSP billing. Each of the functional unbundling cases was discussed in previous Commission Reports and will not be restated here.

Wires Charges Calculations

The Restructuring Act directs the Commission to establish wires charges for each incumbent electric utility effective upon the commencement of customer choice. In order to establish such wires charges, the Commission must determine projected market prices for energy and subtract those projected market prices from each utility's embedded generation rate. According to the Act, these projected market prices and the resulting wires charges may be adjusted on no more than an annual basis. The embedded generation rate includes fuel costs as determined by the Commission pursuant to § 56-249.6 as amended by the General Assembly in 2004.

Market price determination for retail access began in 2001 with the market price and wires charges determinations for APCo and DVP.[10] In 2002, the Commission established the market price determination methodology for the electric distribution cooperatives within the Commonwealth and by early 2004 had completed the determination of wires charges for all

[9] A bundled rate is a single rate for electricity comprised of all service elements: generation, transmission and distribution.
[10] Delmarva and Potomac Edison waived their right to wires charges throughout the transition period.

relevant electric cooperatives in the Commonwealth.

The Commission approved the basic methodology for APCo and DVP in its order of November 19, 2001 in Case No. PUE-2001-00306. This order set a general schedule for making annual changes to wires charges for each calendar year. If either company wishes to revise its wires charges for the upcoming calendar year, it must file market price and, if applicable, fuel factor applications with the Commission by July 1 of the current year. This allows wires charge determinations to be finalized in October or about three months before they will be implemented and enables the companies to make necessary calculations and carry out compliance filings before the implementation date. Such a timely determination also allows time for CSPs to formulate and implement pricing and marketing strategies for the following year.

In its November 19, 2001 order, the Commission also decided that the projected market prices for generation to be used in wires charge calculations should be based on "forward prices"[11] for electric power traded in the wholesale market. The Commission made this decision in the belief that forward prices are the most appropriate indicators of projected market prices and that forward markets were functioning reasonably well.

The forward price method considers prices at two delivery or receipt points (Cinergy and PJM West) for a calendar year of data. Although DVP has incorporated a value for capacity in its projected market price formulation, there is no explicit inclusion of a capacity value within the generally approved methodology. Price adjustments for load-shaping are accomplished using methods similar to those employed in the pilot programs. Finally, the Commission specified a method for adjusting market prices in order to consider the cost to transport power to distant markets.

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[11] "Forward prices" generally refer to agreements made today for the future purchase and sale of a specified

This methodology has been modified only slightly following the Commission's November 19, 2001 Order. In 2002, the Commission allowed DVP to incorporate a capacity adder into the projected market price for the company's service territory for the calendar year 2003 and beyond based on the historical monthly values of capacity as reflected in the PJM Capacity Credit Market. Subsequent to the Commission's Order, DVP has incorporated the capacity adder into its market price calculations. This adder, by raising market prices, lowers the resulting wires charges and, thus, provides some additional "headroom" for any CSP competing in the Virginia retail electricity market.

Projected market prices for DVP during 2005 were above the company's capped generation rates for most rate classes meaning that there would be no wires charges for the company's customers in these classes. In light of this, DVP waived any applicable wire charges for the remaining classes for 2005; therefore, wires charges are not applicable to any DVP customers that choose to take service from a CSP during 2005. On July 1, 2005, DVP submitted an application to potentially impose wires charges in 2006. This application is currently under review by Staff.

This year, APCo has informed the Commission that, as has been the case since 2001, the company does not seek to impose a wires charge for any of its Virginia customers for the upcoming year. APCo's decision not to seek wires charges for 2006 implies that projected market prices for 2006 within its service territory will again be above its capped generation rate.

With respect to the Cooperatives, on May 24, 2002 in Case No. PUE-2001-00306, the Commission adopted a proposal from the Cooperatives and ruled that the basic methodology for calculating generation market prices that it approved for DVP and APCo should be utilized

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quantity of electric power at some specified location for a specified time period.

by the Virginia electric distribution cooperatives,[12] subject to the Commission's continued review. There is, however, one basic difference in the methodology as applied to the Cooperatives as opposed to that for DVP and APCo. Whereas, the capped rates for generation for the investor-owned utilities are adjusted annually for the cost of fuel on a prospective basis, the capped rates for the Cooperatives are adjusted monthly on an historical basis. This distinction is to allow the Cooperatives to continue a decades-old practice that allows them to make monthly adjustments for their wholesale cost of power. For consistency, the Commission allows the Cooperatives to vary the market price monthly by the same amount as the wholesale cost of power adjustment in order to maintain a constant wires charge throughout the year.

For the most part, projected market prices among the Cooperatives for 2005 were below the capped generation rates for the Cooperatives, although this situation was not universal. Central Virginia Electric Cooperative, once again, did not seek to collect wires charges. In addition, projected market prices for BARC Electric Cooperative and Craig-Botetourt Electric Cooperative were above the respective cooperatives' capped rates, meaning that neither cooperative is collecting wires charges in 2005. With respect to the remaining cooperatives, each imposed a wires charge for one or more of its rate schedules for 2005.

Price-to-Compare

Once rates have been unbundled and the appropriate wires charges have been calculated, a company's price-to-compare can be determined. The price-to-compare is a cents per kilowatt-hour benchmark value that can be used by a customer to evaluate offers from competitive service providers.

[12] A&N Electric Cooperative, BARC Electric Cooperative, Central Virginia Electric Cooperative, Community Electric Cooperative, Craig-Botetourt Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Inc., Northern Virginia Electric Cooperative, Prince George Electric Cooperative, Rappahannock Electric Cooperative, Shenandoah Valley Electric Cooperative, and Southside Electric Cooperative.

The price-to-compare is determined by taking the sum of the unbundled generation rate and the unbundled transmission rate and subtracting the wires charge. If a company does not have a wires charge, because its embedded generation rate is less than the current estimated market price, or if a company has waived its right to a wires charge, the price-to-compare is the sum of the unbundled generation and unbundled transmission rates.

As described above, none of the investor-owned utilities imposed a wires charge component within its prices-to-compare during 2005, while all but three of the Cooperatives included a wires charge component within the respective prices-to-compare for at least one or more of its rate schedules.

The table below shows the prices-to-compare for the investor-owned utilities in Virginia. A similar table for the electric distribution cooperatives is not shown given that, as described above, the Cooperatives' price-to-compare changes on a monthly basis due to the application of monthly wholesale power adjustments.

The 2005 price-to-compare values for the subject investor-owned utilities are:

Customer Class	DVP	APCo	PE	Delmarva
Residential	6.078¢/kWh	3.366¢/kWh	3.87¢/kWh	6.47¢/kWh
Small Commercial	5.699¢/kWh	3.187¢/kWh	3.96¢/kWh	7.00¢/kWh
Large Commercial	5.435¢/kWh	3.705¢/kWh	3.90¢/kWh	Not applicable
Small Industrial	4.629¢/kWh	3.082¢/kWh	3.55¢/kWh	6.73¢/kWh
Large Industrial	4.217¢/kWh	2.901¢/kWh	3.34¢/kWh	6.00¢/kWh
Churches	6.651¢/kWh	3.104¢/kWh	Not applicable	Not applicable

As can be seen, the price-to-compare differs among classes of customers. The values above are averages for each customer class. The actual price-to-compare for an individual customer will vary depending upon that customer's usage and rate schedule.

New market price and wires charge calculations are scheduled to be completed in October for use in 2006. Soon after that time, the new price-to-compare values will also be available. Price-to-compare information will appear on the monthly bill of customers who have not yet chosen an alternative supplier.

The Restructuring Act as amended by the 2004 Session of the General Assembly as Senate Bill 651, directs the Commission to promulgate rules and regulations, and adopt certain market-based pricing methodologies, in order to implement two new provisions of the Act. One of the new statutory provisions relate to the permissible wires charges pursuant to § 56-583 of the Act. The Commission initiated a proceeding with its Order of June 16, 2004 in Case No. PUE-2004-00068[13], to permit an exemption to any wires charges imposed by the electric LDC.

The statutory exemption permits such customers to elect up-front to forego paying an LDC's wires charges when switching supply service to a CSP, and agreeing to forego capped-rate service and pay market-based costs upon any future return to the LDC. The process to establish this exemption program parallels the process to establish another exemption program regarding minimum stay provisions. The status of these programs is further discussed in the section regarding minimum stay.

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[13] Dockets regarding restructuring issues may be found on the SCC's website at: http://www.scc.virginia.gov/caseinfo.htm .

CONSUMER EDUCATION

The Virginia Energy Choice ("VEC") consumer education program continued for the past year in a state of limited activity. The main functions of the program consisted of responding to public inquiries about the status of retail competition and maintaining information resources on the restructured energy market available to consumers on a website and a toll-free information line. The program distributed over 4,000 VEC consumer guides and other publications over the last year.

The VEC website (www.vaenergychoice.org) has extensive information on the changes coming to the energy market in Virginia and is routinely updated. The site receives between 8,700 and 10,600 individual visits per month. Web visitors can print information sheets or request consumer guides be mailed to them. The SCC also responds to a monthly average of 15 email inquiries from the site.

The VEC toll-free information line (1-877-YES-2004) is supported by an automated system that provides callers with the choice of listening to a brief recording on energy restructuring, leaving address information to receive consumer education materials, or requesting a call from SCC staff. The information line continues to receive between 500 and 600 calls per month. In an average month, 18 callers leave messages for SCC staff to respond to general questions about choice and energy related topics.

Staff is experiencing an increase in the number of calls and emails regarding the lack of electric choice and limited natural gas choice. Consumers are contacting CSPs from the list of suppliers on the website only to find that no CSP is offering energy supply at a price to which the customer may attribute savings. Rising energy costs encourage consumers to seek relief by contacting the utilities, which in turn refer the consumers to the VEC's website, only to find no competitive offerings among alternative CSPs.

In the coming year, the SCC expects to maintain the VEC consumer education program at the existing modest level and provide for necessary updates to education materials. Conditions in the competitive energy supply market will determine the size and scope of future energy choice outreach activities.

DEVELOPMENT OF A COMPETITIVE STRUCTURE

This section details activities underway to continue the establishment of the framework within which effective competition may develop. While these activities cannot, in and of themselves, assure that competition will flourish, there is no doubt that a competitive market will require both rules to guide behavior and systems to control business operations. In addition, the continuing development of our energy infrastructure, including power plants, transmission lines and natural gas pipelines, is an essential element of future energy reliability. Finally, properly functioning regional transmission organizations are generally recognized as a necessity for an effective competitive wholesale market, which is a precursor to an effective retail market.

Rules Governing Retail Access

The Restructuring Act directed the SCC to promulgate regulations to guide the transition.[14] The Rules Governing Retail Access to Competitive Energy Services ("Retail Access Rules" or "Rules"), adopted by Commission Order in Case No. PUE-2001-00013,[15] currently consist of 12 sections in Chapter 312 (20 VAC 5-312-10 et seq.) of Title 20 of the Virginia Administrative Code and pertain to various relationships among the local distribution companies, competitive service providers and retail customers.

The Commission's Staff continues to monitor and evaluate the development of the energy marketplace, including our experiences in Virginia, and recommend further adjustments to such Rules, if necessary. Future legislative or Commission decisions may also affect the

[14] The rules were to be developed for both a competitive electricity market and a competitive natural gas market. Our focus in this report is the electricity market.

[15] The Rules Governing Retail Access to Competitive Energy Services are available on the Commission's website at: http://www.scc.virginia.gov/division/restruct/rules.htm .

developing energy marketplace. The Retail Access Rules will be revised and amended as needed to incorporate future rules that may be adopted by the SCC.[16]

Minimum Stay

The current Retail Access Rules permit the local distribution companies under certain circumstances, to require large commercial and industrial customers who return to capped rate service to remain a customer of the LDC for a minimum period of 12 months.[17] The Restructuring Act as amended by the 2004 Session of the General Assembly as Senate Bill 651, directs the Commission to promulgate rules and regulations, and adopt certain market-based pricing methodologies, in order to implement two new provisions of the Act. One of the new statutory provisions relates to the minimum stay requirements adopted by the Commission pursuant to § 56-577 E of the Act. The Commission initiated a proceeding with its Order of June 16, 2004 in Case No. PUE-2004-00068[18], to permit an exemption to the current minimum stay requirement.

The statutory exemption permits such customers to elect to accept market-based costs for electric energy as an alternative to being subject to the 12-month minimum stay provision. The recent Commission Order charged the Staff to invite interested parties to participate in a work group to assist the development of the rules, as well as an appropriate methodology, necessary to implement this new statutory provision. Several questions were also included in the Commission Order for interested parties to provide responses to prompt discussion at the initial work group meeting held on August 19, 2004. Two additional meetings were held on

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[16] Dockets regarding restructuring issues may be found on the SCC's website at: http://www.scc.virginia.gov/caseinfo.htm .

[17] Retail Access Rule 20 VAC 5-312-80 Q

[18] Dockets regarding restructuring issues may be found on the SCC's website at: http://www.scc.virginia.gov/caseinfo.htm .

September 10th and 21st, to further assist Staff in developing its report which was submitted to the Commission on November 19, 2004.

The SCC issued an Order Inviting Comments on December 6, 2004. This Order directed electric utilities to submit compliance plans with the proposed rules by January 10, 2005 and interested parties to submit comments regarding Staff's report, the proposed rules, and the utilities' compliance plans by February 7, 2005. Staff was directed to submit any reply comments by February 21, 2005. Upon review of the information submitted, Staff realized the need for more extensive discussions with each utility to thoroughly understand the respective proposals. Staff sought and was granted extensions to submit its report by May 27, 2005, upon which it complied.

Further comments were submitted by various parties narrowing the list of outstanding issues. Generally, the proposed rules appeared acceptable and issues regarding the "reasonable margin" and "administrative costs" components of market-based costs clearly became the most controversial. Suggestions regarding further work group discussions to attempt to resolve the wide range of opinions among the parties regarding the two large outstanding issues were accepted by Staff. Such a meeting was held on July 19, 2005 and the discussions have led to further settlement discussions among the parties, which are not yet complete.

Staff is hopeful that these further discussions will lead to a settlement of issues to move forward without a hearing to adopt the rules governing the exemption programs and to establish the methodology to determine market-based costs to be used in these programs.

Competitive Metering Provisions

On August 19, 2002, the Commission entered an Order in Case No. PUE-2001-00298 approving rules implementing competitive electricity metering services for the elements of meter data availability and accessibility effective January 1, 2003. Subsequently, on July 11, 2003, the Commission entered an Order adopting rules implementing customer ownership of meters by large industrial and large commercial customers effective January 1, 2004.

Following additional investigation, the Commission issued an Order on July 16, 2004, indicating that it was premature to implement additional elements of competitive metering. The Commission directed the Staff to continue to monitor regulated and competitive market developments in metering and to report on any notable developments, including appropriate corresponding recommendations for the implementation of additional elements of competitive metering. At the current time, Staff has not observed significant developments with respect to metering activity nationally that would warrant consideration of additional elements of competitive metering in Virginia.

Competitive Billing Provisions

On August 31, 2002, the Commission issued an Order in Case No. PUE-2001-00297, adopting rules for CSP consolidated billing. The Commission also found that an EDI workaround approach for implementation of CSP consolidated billing was reasonable on an interim basis, recognizing that such an approach will need to be replaced with standardized EDI protocols as the competitive market develops and the volume of competitive billing increases. At the present time, the development of a competitive retail electricity market in Virginia has been extremely limited; no competitive retail suppliers have expressed interest in CSP consolidated billing.

Aggregation

The Restructuring Act authorizes the provision of aggregation services for the Commonwealth's retail electricity customers. Section 56-576 of the Act defines aggregator,

§56-588 details the licensing of aggregators, and §56-589 authorizes municipal and state aggregation. Aggregation service is the purchasing or arrangement of the purchase of electric energy for sale to two or more retail customers.

The Commission established an investigation of aggregation issues with Case No. PUE-2002-00174. Although there has not been any market activity since the Commission's Order of August 24, 2004, including DVP's municipal aggregation pilot program, four additional aggregators have been licensed by the Commission.

Distributed Generation

Distributed generation involves moving the generation of electricity away from large central units to smaller units located closer to the point of consumption.[19] In accordance with §56-578 of the Restructuring Act, the Commission instructed the Staff to work with interested parties to develop proposed interconnection standards for distributed generation. The Act specifies that the interconnection standards "shall not be inconsistent with nationally recognized standards acceptable to the Commission."

Following several work group meetings and assistance of interested stakeholders, Staff drafted proposed interconnection standards for Virginia. The National Association of Regulatory Utility Commissioners ("NARUC") has since adopted a set of distributed generation rules that States are encouraged to adopt. Staff awaits further direction and decision of the Institute for Electrical and Electronic Engineers ("IEEE") and its efforts to set national standards for distributed generation interconnections ("IEEE-1547"), and of the Federal Energy Regulatory Commission's activities to develop interconnection procedures.

[19] In May of 2000, the Commission issued rules governing net energy metering promulgated pursuant to § 56-594 of the Restructuring Act. The net metering rules establish interconnection guidelines and tariffs under which an electric customer may interconnect a small wind, hydro or solar generating facility to the grid. The rules may be found at: http://www.scc.virginia.gov/caseinfo/pue/e990788.htm .

Chapter 827 of the 2004 Acts of the General Assembly amended the net metering provisions of the Code of Virginia, Section 56-594 of the Restructuring Act to revise the definition of eligible customer generator. The definition now refers to a nonresidential customer that owns and operates an electric generation facility that, among other things, has a capacity of not more than 500 kW. The capacity limit for nonresidential customers previously was 25 kW.

In response to this statutory change, by Order dated June 3, 2004, the Commission initiated Case No. PUE-2004-00060. Many parties were involved in the proceeding including APCO, the Virginia Department of Environmental Quality, Virginia Power, the Maryland, District of Columbia, Virginia Solar Energy Industries Association, Virginia Wind Energy Collaborative, and the Old Mill Power Company. The proceeding involved a workgroup meeting that lead to a Staff report. After considering substantial comments by the parties to the proceeding, by Order dated April 20, 2005, the Commission adopted final regulations governing net energy metering.

Business Practices

The North American Energy Standards Board ("NAESB") serves to develop and promote standards leading to a seamless marketplace for wholesale, and retail, natural gas and electricity.[20] NAESB is accredited as a standards-setting body from the American National Standards Institute, charged by the FERC to develop business practices for use by market participants while moving toward a more uniform marketplace. NAESB ensures that its implementation standards and business practices will receive and utilize the input of all industry sectors through its open membership and balanced voting processes. This process

[20] Additional information regarding the NAESB may be found at: http://www.naesb.org .

continues to pursue the development of national standards regarding electronic protocols for regions to converge to the same EDI standards and consistent business rules to better promote a robust competitive energy market.

Staff continues to monitor the activities of each quadrant and the various subcommittees to establish standards and business practices. Staff also participates with NAESB's monthly conference calls to update regulators and continues to serve on the Advisory Committee to NAESB.

Generation and Transmission Additions

Since 1998, eleven generating plants have been built and placed into commercial operation within the Commonwealth, adding 4,150 megawatts ("MW") to existing generation physically located in Virginia.[21] Approval of six additional facilities has been granted by this Commission summing to 3,865 MW, of which one facility of 680 MW has since been withdrawn. The remaining facilities, totaling 3,185 MW, are in various stages of development to move forward, but have not yet begun construction. The table at the end of this section provides further detail regarding applications for new facilities.

Changes within the electricity marketplace under a competitive regime, actions by the FERC, and the financial investment and capital markets have caused the electric industry to explore alternatives to traditional integrated resource planning. Evolvement of RTOs to include a broader number of market participants and to cover wider service areas has changed the complexion of the future electric industry. New capacity, generation as well as transmission, will be realized when market participants recognize and react to market signals such as reliability, price, customer service, load growth and economics. Such response will

[21] These new plants are comprised of three Dominion generating stations, two ODEC facilities, and six independent power plants, representing 1,500 MW, 940 MW, and 1,710 MW, respectively.

likely include physical construction and enhancement as well as contractual and financial alternatives.

As more independent generators begin commercial operation and suppliers utilize a variety of capacity purchases to serve customer load, the traditional reserve margin loses significance. Difficulties arise in determining which supply sources and which customer loads should be included at any particular time to determine such a calculation.

Expansion of transmission facilities is also needed to accommodate expected customer demand and required energy supply. Construction of AEP's 765-kV electric transmission line in southwestern Virginia continues with a target operation date during the summer of 2006. Certificates for two shorter transmission lines were granted in 2004 and two certificate applications are currently pending before the Commission. Additionally, several new natural gas pipelines are now in service or have been approved.

Summary of Construction Activity in Virginia
As of August 1, 2005

New power plants in operation

Company/Facility	*Size*	*Location*	*Docket*	*Fuel*	*C.O.D.**	*Hearing*	*Order*
Commonwealth Chesapeake	300 MW	Accomack County	PUE960224	3-OilCT	sum 01	1/23/97	8/5/98
Dominion Virginia Power	600 MW	Fauquier County Remington	PUE980462	4-GasCT	sum 00	1/05/99	5/14/99
Wolf Hills Energy, LLC	250 MW	Washington County Bristol	PUE990785	5-GasCT	sum 01	4/27/00	5/2/00
Dominion Virginia Power	360 MW	Caroline County Ladysmith	PUE000009	2-GasCT	sum 01	5/23/00	10/10/00
Doswell Limited Partnership	171 MW	Hanover County Doswell	PUE000092	1-GasCT	sum 01	6/13/00	6/15/00
Allegheny Energy Supply	88 MW	Buchanan County	PUE010657	2-C/GCT	Jun 02	none	6/25/02
Dominion Virginia Power-Possum	540 MW	Prince William County PP	PUE000343	convert/GasCC	May 03	1/16/01	3/12/01
Louisa Generation, LLC (ODEC)	472 MW	Louisa County BoswllTavrn	PUE010303	5-Gas CT	Jun 03	11/14/01	7/17/02
Tenaska Virginia Partners I, LP	885 MW	Fluvanna County	PUE010039	Gas CC	May 04	3/13/02	4/19/02
INGENCO Wholesale Power, LLC	16 MW	Chesterfield County	PUE-2003-00538	48-LFGas	Jun 04	none	4/12/04
Marsh Run Generation, LLC (ODEC)	468 MW	Fauquier County	PUE020003	3-GasCT	Sep 04	5/21/02	11/6/02
	4,150 MW						

New power plants with SCC certificates currently under construction.

New power plants with SCC certificates, but not yet under construction.

Company/Facility	*Size*	*Location*	*Docket*	*Fuel*	*C.O.D.**	*Hearing*	*Order*
Competitive Power Ventures (8/31/01/2/02)	520 MW	Fluvanna County	PUE010477	Gas CC	spr 06	1/9/02	SCC app 10/7/02
Tenaska Virginia Partners II, LP (8/15/01)	900 MW	Buckingham County	PUE010429	Gas CC	n/a	5/28/02	SCC app 1/9/03
CPV Warren, LLC (2/14/02)	520 MW	Warren County	PUE020075	2-GasCC	spr 05	7/24/02	SCC app 3/13/03
Chickahominy Power, LLC (1/4/02)	665 MW	Charles City County	PUE010659	Gas CT	n/a	5/1/02	SCC app 3/12/04
James City Energy Park, LLC (3/8/02)	580 MW	James City County	PUE-2002-00150	2-GasCC	win 05	9/18/02	SCC app 3/12/04
White Oak Power Co., LLC (5/9/02)	680 MW	Pittsylvania County	PUE-2002-00305	4-Gas CT	sum 04	10/24/02	SCC app 8/1/03,**w/drawn**
	3,865 MW >>> 680 withdrawn **leaving 3,185 MW**						

New power plants that have applied for an SCC certificate

Company/Facility	*Size*	*Location*	*Docket*	*Fuel*	*C.O.D.**	*Hearing*	*Order*
Duke Energy Wythe, LLC (12/27/01)	620 MW	Wythe County	PUE010721	Gas CC	sum 04	6/25/02	**Dismissed 5/20/04**
CinCap-Martinsville	330 MW	Henry County	PUE010169	4-GasCT	sum 03	9/18/01	**Dismissed 4/29/03**
Kinder Morgan VA, LLC	560 MW	Cumberland County	PUE010722	Gas CC	sum 04	12/17/02	**Dismissed 1/14/03**
Kinder Morgan of Virginia, LLC	550 MW	Brunswick County	PUE010423	Gas CC	win 04	11/7/01	**Dismissed 11/1/02**
Henry County Power/Cogentrix (MB)	1,100 MW	Henry County	PUE010300	Gas CC	sum 04	10/17/01	**Dismissed 8/26/03**
Loudoun County Power/Tractebel (WS)	1,400 MW	Loudoun County	PUE010171	Gas CC/CT	04/05	12/6/01	**Dismissed 3/27/02**
Mirant Danville, LLC (KH)	870 MW	Pittsylvania County	PUE010430	Gas CT/CC	03/04	12/5/01	**Dismissed12/16/03**
Total	**5,430 MW** >>> withdrawn/dismissed **leaving 0 MW**						

*Commercial Operation Date

Company/Facility	***Size***	***Location***	***Docket***	***C.O.D.***	***Order***
Transmission lines					
APCo	765 kV-90 mi	Wymoing-Jackson's Ferry	PUE970766	6/06	5/31/01 approved, under construction
DVP	230 kV- 4 mi	Loudoun	PUE010154	5/06, 5/07	6/27/02 approved, under construction
DVP	500 kV-8 mi	Morrisville-Loudoun	PUE-2004-00062	5/07	7/15/05 approved
DVP	230kV – 11.8 mi	Trabue-Winterpock	PUE-2004-00041	11/06	9/28/04 approved, under construction
DVP	230kV – 8 mi	Loudoun	PUE-2002-00702	n/a	appealed to Supreme Court
DVP	230kV – 7 mi	Norfolk	PUE-2004-00139	5/07	pending
DVP	230kV- 16 mi	Pleasant View-Hamilton	PUE-2005-00018	6/08	pending
Natural gas pipelines					
DVP	20" – 14 mi	Prince William County	PUE000741	2003	SCC app 11/5/01, in-service 7/03
Duke Energy Patriot Extension	24"-95 mi	Wythe to Rockingham Cty	FERC	2004	FERC app 11/20/02, in service 2/04
Dominion Transmission Greenbrier	30"-279 mi	Charleston to Rockingham	FERC	2007	FERC app 4/9/03, extended 2 years
Saltville Gas Storage Co., LLC	24"-7 mi	Saltville / Chilhowie	PUE010585	2003	SCC approved 1/22/03, in-service 8/03
Tenaska VA II Partners, LP	20"-14 mi	Buckingham County	PUE010429(ref)	n/a	n/a
Cove Point East Pipeline capacity expansion	87 mi	Maryland to Loudoun	FERC	2008	pending FERC approval
Cove Point LNG terminal capacity expansion	9.6BCF storage	Cove Point, Maryland	FERC	2008	pending FERC approval

Regional Transmission Organization membership

AP (PJM West)	PUE-2000-00736	Order of 10/8/04 approving transfer of operation of transmission facilities to PJM West.
Conectiv (PJM East)	PUE-2001-00353	Order of 5/20/04 recognizes current membership in PJM since 3/97 satisfies RTE Rules.
KU (MISO)	PUE-2000-00569	EXEMPT 2003 via §56-580 G
AEP (PJM West)	PUE-2000-00550	Order of 8/30/04 approving transfer of operation of transmission facilities to PJM West.
DVP (PJM South)	PUE-2000-00551	Order of 11/10/04 approving transfer of operation of transmission facilities to PJM.

RTE Development

Section 56-579 of the Restructuring Act requires incumbent electric utilities to establish or join regional transmission entities ("RTEs")[22] as part of the transition to retail competition. This obligation is imposed on each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity. Section 56-579 also requires the State Corporation Commission to determine "whether to authorize transfer of ownership or control from an incumbent electric utility to a regional transmission entity." Behind this requirement was an expectation that RTEs would manage and control the transmission assets of Virginia's utilities with the objective of meeting the transmission needs of electric generation suppliers both within and outside Virginia.[23]

On April 2, 2003, HB 2453 was placed into law. HB 2453 amended §§56-577 and 56-579 of the code of Virginia to require utilities seeking to transfer control of their transmission facilities to an RTE to submit "a study of the comparative costs and benefits thereof, which study shall analyze the economic effects of the transfer on consumers, including the effects of transmission congestion costs." HB 2453 also prohibits the transfer of control prior to July 1, 2004, and requires the Commission to conduct a public hearing regarding any such request. The Restructuring Act previously required notice and an opportunity for a hearing. HB 2453 also states that "each incumbent electric utility shall file an application for approval pursuant to this section by July 1, 2003, and shall transfer management and control of its transmission assets to a regional

[22] RTE and RTO (Regional Transmission Organization) are essentially synonymous terms. The former is used in the Act; the latter is the Federal Energy Regulatory Commission's preferred acronym.
[23] § 56-579 A 2 d.

transmission entity by January 1, 2005, subject to Commission approval as provided in this section."

All of Virginia's investor-owned electric utilities have now shifted management of their transmission facilities to an RTE. APCo, Allegheny Power, Delmarva and Dominion are participating in PJM[24] and Kentucky Utilities is participating in the MISO.[25]

Appalachian Power

Appalachian Power filed a substitute application for approval to transfer functional control of its transmission facilities to PJM, Case No. PUE-2000-00550. On January 15, 2004, the Commission issued a procedural schedule in setting the matter for notice and hearing. APCo was directed to file testimony and exhibits by March 1, 2004; respondents were directed to file testimony and exhibits by May 24, 2004; and Staff was directed to file testimony and exhibits by June 22, 2004. The public hearing took place on July 27, 2004. During the hearing, APCo; the Commission's Staff; the Attorney General; the Old Dominion Committee for Fair Utility Rates; PJM; and Edison Mission Energy offered a stipulation recommending that the Commission approve APCo's participation in PJM subject to certain specified conditions. The conditions set-forth in the stipulation included agreements by APCo and the parties regarding future ratemaking proposals that may come before the Commission; modest bill credits for the period 2005-2010; a curtailment protocol specifying conditions under which service to Virginia consumers may be curtailed; and information reporting requirements for APCo and PJM.

[24] Delmarva has participated in PJM since PJM's inception decades prior to passage of the Restructuring Act. PJM accepted control of Allegheny's transmission facilities on April 1, 2002, AEP's on October 1, 2004, and Virginia Power's on May 1, 2005.

[25] "MISO" is the Midwest Independent System Operator. MISO began offering transmission service over

On August 30, 2004, the Commission issued an order modifying the curtailment protocol specified in the stipulation and approving the transfer of control of APCo's Virginia jurisdictional transmission facilities to PJM. PJM assumed control of AEP's transmission system on October 1, 2004.

Allegheny Power

Allegheny filed an application to transfer control of its transmission facilities to PJM under an arrangement known as PJM West, Case No. PUE-2000-00736.

On January 30, 2002, FERC issued an Order that, among other things, permitted Allegheny and PJM to form PJM West. Pursuant to that order, Allegheny turned over operational control of its transmission facilities to PJM on March 1, 2002 and currently operates under the LMP model.

The Commission held a public hearing on September 28, 2004 to consider Allegheny's request to join PJM. During the hearing, Allegheny; the Commission's Staff; the Attorney General; and PJM; offered a stipulation recommending that the Commission approve Allegheny's participation in PJM subject to certain specified conditions. The conditions set-forth in the stipulation included a curtailment protocol specifying conditions under which service to Virginia consumers may be curtailed and information reporting requirements for Allegheny and PJM. On October 8, 2004, the Commission issued an order approving the stipulation and Allegheny's request to transfer operation and functional control of its transmission facilities to PJM.

Delmarva

KU's transmission facilities on February 1, 2002.

On October 16, 2000, Delmarva filed a Motion with the SCC in Docket No. PUE-2000-0086[26], requesting the Commission to determine that Delmarva's membership in PJM constituted compliance with the requirements of the Restructuring Act and the SCC's Regulations Governing Transfer of Transmission Assets to Regional Transmission Entities, 20 VAC 5-320-10 *et seq.* ("RTE Rules").

After a number of procedural orders and responsive pleadings, the Commission issued an order dated March 4, 2004 requiring, among other things, Delmarva to file a legal memorandum regarding a question of whether the Commission had authority under § 56-579 of the Code of Virginia to grant "prior approval" of a transfer that occurred long before enactment of that statute. On March 26, 2004, Delmarva filed its response. Delmarva asserted that on July 1, 1999, the effective date of the Restructuring Act, it had already transferred "the management and control of its transmission system" in the Commonwealth to the PJM Interconnection, L.L.C., and that this transfer had occurred on March 31, 1997. Thus, Delmarva contended, that because it retained no management or control over its transmission system, there was nothing to which the Commission could give "prior approval" as envisioned by §56-579 of the Act. Delmarva further argued that Virginia law made clear that newly enacted statutes, such as the Act, could only be given prospective effect and could not be applied retroactively, unless the legislation clearly expressed the intent that it be applied retroactively, or if the legislation affected only procedural and not contractual or other substantive rights.

On April 14 and 16, 2004, respectively, the Staff and the Attorney General filed Responses to Delmarva's filing. All filing parties conclude that the Commission cannot

[26] Delmarva's RTE related requests were subsequently reassigned to Case No. PUE-2001-00353.

apply its new authority under code § 56-579 to Delmarva's membership in PJM, which occurred prior to the passage of the statute.

On May 20, 2004 the Commission found that Delmarva does not now possess, nor did possess as of July 1, 1999, management and control of its transmission facilities within the Commonwealth of Virginia; that the management and control of such facilities is now, and has since at least March 31, 1997, been possessed by PJM; that the Commission was without authority to give "prior approval" to the transfer of management and control that occurred over two years prior to the passage of the Act, which directs all jurisdictional utilities to make such transfers subject to the prior approval of the Commission; that, notwithstanding the Commission's lack of jurisdiction under the limited factual circumstances presented herein, Delmarva's membership in PJM appears to satisfy the requirements of our RTE Rules and is not contrary to the public interest; and that this matter should accordingly be dismissed.[27] The Commission rejected Delmarva's contention that its transmission facilities do not fall within the general jurisdiction of the Act, due to their geographical location on the Eastern Shore. To the contrary, we find that those facilities do comprise a part of "Commonwealth's interconnected grid and we retain jurisdiction over any subsequent transfer of operation and control of them by Delmarva or any other operator.

Dominion Virginia Power

On June 27, 2003, DVP filed an application seeking to join PJM. On September 26, 2003, the Commission entered its Order for Notice in this proceeding. The Order for Notice directed the Dominion, among other things, to file certain relevant information

[27] See PUE-2001-00353 at: http://www.scc.virginia.gov/caseinfo.htm .

and supporting information by November 26, 2003. This date was subsequently amended by additional Orders of the Commission to March 15, 2004.

On December 22, 2003, the Commission issued a procedural schedule setting this matter for notice and hearing. Respondents were directed to file testimony and exhibits by July 15, 2004, and Staff was directed to file testimony and exhibits by August 16, 2004. A public hearing regarding DVP's request was held on October 12, 2004. During the hearing, DVP; the Commission's Staff; the Attorney General; Old Dominion Electric Cooperative; PJM; Chaparral (Virginia) Inc., the Municipal Electric Power Association of Virginia; Central Virginia Electric Cooperative; and Craig-Botetourt Electric Cooperative offered a partial stipulation recommending that the Commission approve DVP's participation in PJM subject to certain specified conditions. The conditions set-forth in the stipulation included a curtailment protocol specifying conditions under which service to Virginia consumers may be curtailed, and information reporting requirements for DVP and PJM. On November 10, 2004, the Commission issued an Order accepting the stipulation and approving the transfer of control of DVP's Virginia jurisdictional transmission facilities to PJM. PJM assumed control of DVP's transmission system on May 1, 2005.

Dominion also serves over 100,000 customers in northeastern North Carolina. On April 2, 2004, pursuant to North Carolina law, Dominion filed with the North Carolina Utilities Commission (NCUC) an application to transfer to PJM, operational control of its transmission facilities located in North Carolina.

The State of North Carolina has chosen not to restructure its retail electric industry. Regarding Dominion's filing, the NCUC concluded that, as originally proposed by Dominion and as subsequently modified in a Joint Offer of Settlement, approval of the application would not be justified by the public convenience and necessity.[28] However, the NCUC did conclude that approval of Dominion's application would be justified subject to the imposition of certain additional conditions intended to provide sufficient protections for Dominion's North Carolina retail ratepayers. The NCUC conditions, which were subsequently agreed to by Dominion and PJM, are as follows:

1. That Dominion's North Carolina retail ratepayers shall be held harmless from all direct and indirect effects and costs, either related to operations, quality of service, reliability, or rates, arising from its integration with PJM including, specifically, the following:

    a. As stated in the testimony of Dominion witnesses, Dominion's North Carolina retail customers shall continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law using the same ratemaking methodology as that employed by this [NCUC] Commission as of the time of Dominion's joining PJM notwithstanding Dominion's integration into PJM or decision to participate in any capacity or energy market administered by PJM; that is, under no circumstance(s) or event(s) shall the costs of generation and transmission, among other things, included in Dominion's N.C. retail rates be greater than the lesser of (1) such costs determined on the basis of historical, embedded costs, calculated consistent with the Commission's currently existing rate base, rate-of-return ratemaking practices and procedures, or (2) the marginal costs of generation and transmission supplied into or purchased from PJM;

[28] See Orders of the North Carolina Utilities Commission, Docket No. E-22, Sub 418. March 30, 2005 and April 19, 2005.

b. Dominion shall continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase from other sources in order to meet its native load requirements before making power available for off-system sales;

c. Dominion shall take all reasonable and prudent actions necessary to continue to provide its North Carolina retail customers with the same (or higher) superior level of bundled electric service as that provided prior to Dominion's integration with PJM, including, for example, reliable generation, transmission, and distribution service; minimization of power outages, efficient restoration of service; and responsive customer service;

d. Dominion shall not include in base rates: (a) PJM administrative fees or any replacement mechanism for such fees approved by the FERC; (b) PJM transmission congestion costs or revenues from PJM for financial transmission rights (FTRs) or auction revenue rights (ARRs) or any replacement mechanism for such cost and revenues approved by the FERC; (c) any increase in transmission service charges to the Company resulting solely and directly from a change in rate structure from license plate rates to another rate structure for recovering the embedded costs of transmission facilities used to provide Network Integration Transmission Service; (d) any increase in transmission charges resulting from charges associated with regional transmission expansion costs that are chargeable under the PJM Tariff to the Dominion zone, and which are not included in the Company's transmission revenue requirement; or (e) any increase in transmission costs to the Company or any revenues resulting from the FERC's orders in Docket Nos. ER04-829 and ER05-6, et al. imposing the Seam Elimination Cost Adjustments (SECAs);

e. Dominion shall allocate sufficient FTRs, ARRs, or other revenues toward its fuel costs to offset any congestion charges or other fuel-related costs resulting from Dominion joining PJM and sought to be recovered from Dominion's North Carolina retail ratepayers through the operation of G.S. 62-133.2; and

f. Neither PJM, Dominion nor any affiliate shall assert in any proceeding in any forum that federal law, including, but not limited to, the Public Utility Holding Company Act of 1935 (PUHCA) or Federal Power Act (FPA), preempts the [NCUC] Commission from exercising such authority as it may otherwise have (or would have were Dominion not a member of PJM) under North Carolina law to set the rates, terms, and conditions of retail electric service to Dominion's North Carolina retail ratepayers and that Dominion shall bear the full risks of any such preemption;

2. That Dominion and PJM shall, consistent with, and to the extent not altered by, the above additional regulatory conditions and this Notice of Decision, comply with the terms of the Joint Offer of Settlement filed December 16, 2004;

3. That Dominion and PJM shall, consistent with the above additional regulatory conditions, comply with the terms of the Settlement Agreement with Progress filed December 16, 2004. Dominion and PJM shall, with regard to all of the signatories thereof, honor, and discharge Dominion's obligations pursuant to, the various VACAR and other regional agreements referenced in the Settlement Agreement, including but not limited to the VACAR Reserve Sharing Agreement, as Dominion would have been so obligated to do prior to Dominion's integration with PJM. In fulfilling this condition, Dominion and PJM shall continue to follow the practices and operating procedures around these agreements that have

been customarily observed by the participants but do not necessary exist in written form; and

4. That Dominion shall continue to comply with all regulatory conditions and codes of conduct previously imposed by the [NCUC] Commission.

Kentucky Utilities

On October 16, 2000, Kentucky Utilities ("KU") filed an application for Commission approval to transfer the operational control over its transmission assets to MISO. MISO assumed control of KU's transmission system on February 1, 2002. On June 28, 2005, KU filed a Motion to Dismiss its Application. In support of its motion, Kentucky Utilities stated that the Virginia General Assembly approved House Bill No. 2637 on March 19, 2003, which added subsection G to § 56-580 of the Code of Virginia and that § 56-580 G suspends the applicability of the Restructuring Act to KU. Accordingly, Kentucky Utilities requested that its application be dismissed without prejudice. On July 26, 2005, the Commission issued an order dismissing KU's request without prejudice.

RTO Prices

Since Virginia's largest electric utilities only recently integrated into PJM, there has not been enough time to gather and review data to understand the real implications on the utilities and respective customers. Although it is too soon to determine the affect on prices from joining PJM, the following table simply shows load-weighted average prices from the most recent information of the largest electric utilities in Virginia since joining PJM.

Dominion Virginia Power	5/05-7/05	$67.11 / MWh
Appalachian Power	10/04-7/05	$41.35 / MWh
Potomac Edison	8/04-7/05	$46.04 / MWh

<u>Significant RTO-Related Dockets at FERC</u>

Virginia's Restructuring Act directs the Commission to participate "to the fullest extent possible" in RTO-related dockets at the FERC (§ 56-579 C). The Commission is also directed by the Act to provide an annual report to the CEUR concerning the Commission's assessment of RTOs relative to the development of competitive markets in Virginia (§ 56-579 F).[29]

As recounted in previous versions of this annual report, the Commission has participated extensively in the RTO-related dockets at the FERC, committing considerable Staff and financial resources to such participation. Such participation began almost immediately after the General Assembly passed the Restructuring Act in 1999, when Dominion Virginia Power, the Appalachian Power Company, and a number of other transmission-owning utilities sought the FERC's approval for the creation of the Alliance Regional Transmission Organization ("Alliance RTO"). The FERC ultimately rejected the Alliance RTO on the basis that it did not conform to all of the requirements of FERC's Order 2000.

Subsequently, the Commission participated fully in a number of significant RTO-related dockets, culminating in the integration of AEP's operating companies (including

[29] The Commission is also charged by § 56-578 G of the Restructuring Act with ensuring that the rules and practices of RTOs are sufficiently mitigating market power in transmission-constrained areas associated with electric generation (capacity or energy) serving Virginia's retail customers. If these rules and practices are insufficient to curb any such market power, the Commission is directed to adjust retail rates for electric generating capacity or energy within these transmission-constrained areas to the extent necessary to protect retail customers from the effects of market power.

Appalachian Power) into the "PJM West" region of the PJM Interconnection, LLC, and the integration into PJM of Dominion as a single-utility PJM region named "PJM South."

The FERC's review of AEP and DVP's proposed integration into PJM ran roughly parallel to corresponding proceedings before the Commission, pursuant to § 56-579 of Virginia's Restructuring Act, requiring Commission approval of the transfer of management and control of these utilities' transmission facilities to PJM. Significantly, however, at the request of Chicago-based utility Exelon, Inc., and others, FERC initiated its first ever challenge to a state's authority to pass on the propriety of such proposed transfers in an extensive proceeding convened before the FERC pursuant to § 205 of the Public Utilities Regulatory Policy Act ("PURPA"). Prior to the commencement of these formal proceedings, FERC issued its preliminary opinion that provisions of Virginia law prevented AEP and PJM from consummating a voluntary agreement to coordinate their facilities and that AEP should be exempted from compliance with these unspecified provisions of Virginia's Restructuring Act. After this "verdict," a formal hearing was conducted before a FERC Administrative Law Judge who initially issued findings supporting FERC's preliminary conclusions. Unsurprisingly, the FERC issued an opinion (Opinion No. 472), upholding its ALJ's findings. Additional litigation ensued and the FERC's proceeding was effectively rendered moot when this Commission approved AEP's integration into PJM in 2004. Ultimately, FERC converted its Opinion No. 472 into a non-binding "policy statement," that could not be appealed into the federal courts.[30]

[30] FERC Docket No. ER03-262-009

With the integration of Virginia's transmission-owning utilities into FERC-regulated RTOs completed, the work of the Commission insofar as participation in FERC dockets continues. There are several significant dockets underway at the FERC as this report goes to publication. All of them have an impact on the price and reliability of electricity provided to Virginia's residential, commercial and industrial customers. These dockets and other significant Orders issued by the FERC are discussed below.

FERC Abandons its controversial Standard Market Design rulemaking.

Effective July 1, 2005, FERC Commissioner Joseph Kelliher replaced Pat Wood as Chairman of the FERC, the latter not having been reappointed to that commission. In a significant action following Commissioner Kelliher's appointment by President Bush to the Chairmanship, the FERC entered an Order in FERC Docket No. RM01-12-000 on July 19, 2005, terminating the controversial Standard Market Design ("SMD") rulemaking the FERC had established in 2002. So ends the saga of a FERC rulemaking so controversial that SMD was, at one time, the subject of special provisions within some versions of the federal energy bill prohibiting or delaying its implementation. The SMD, among other things, made RTO or ISO participation (and FERC oversight thereof) mandatory for all interstate transmission facilities, and (in its original form) asserted jurisdiction over transmission used to provide retail service to native load customers. The FERC offered as a rationale for this "Order Terminating Proceeding," the continuing development of voluntary RTOs and ISOs, and the FERC's announced plans to revisit Order 888, and possibly revise it. In sum, the FERC stated that "the SMD NOPR has been overtaken by events."

Transmission rate increase sought by AEP.

In FERC Docket ER05-751-000, the American Electric Power Company seeks to substantially increase its FERC-regulated transmission rates. These proposed increases, if approved, would be paid by the transmission customers of AEP, including AEP's operating companies such as APCo, which provides service in western and southwestern Virginia. AEP's operating companies, particularly APCo, would likely seek to pass along these transmission rate increases to their retail customers, the timing of which depends on whether and when APCo decides to file a comprehensive rate case with the Commission.

Increased AEP transmission rates would also increase the costs of competitive suppliers seeking to transmit power across the AEP transmission system in order to sell competitive generation supply to retail customers within the Commonwealth, including APCo's Virginia service territory, although there are no such suppliers now operating in Virginia. Furthermore, these rate increases would also be paid by electric cooperatives and municipal power supply systems in Virginia who utilize AEP's transmission system to bring power to their retail customers. The FERC Administrative Law Judge assigned to this case has scheduled a January 24, 2006, hearing date.

<u>FERC looks at PJM's methods for mitigating market power in load pockets.</u>

In FERC Docket EL04-121-000, the FERC is reviewing PJM's current methods for preventing generation owners from hiking up generation prices above reasonable levels for the output of their generation units that must run ("must-run units") in certain areas during periods when demand is high and transmission capacity in these areas is in short supply, or "constrained." A good example of a frequently constrained area within PJM is Virginia's Eastern Shore. Under PJM's current procedures (spelled out in its tariffs on file at the FERC), the wholesale price of must-run units can be capped or limited through the actions of PJM's Market Monitoring Unit ("MMU") during periods when transmission is constrained. One of the questions FERC has raised in this investigation is whether PJM's current price caps (and the actions of PJM's MMU in triggering them) might work to discourage the construction of new generation needed in these so-called load pockets. The FERC's Order initiating this current investigation suggests that "scarcity pricing" may actually be needed in some instances to induce new generation construction. The Commission has intervened in this proceeding.

FERC's investigation of the justness and reasonableness of PJM's current rate design.

This FERC docket (EL05-121-000) was established in May 2005 for the express purpose of determining whether transmission rates within PJM are just and reasonable vis-à-vis cost allocations among PJM members. The catalyst for this proceeding is AEP's assertion that the benefits of its extra high voltage system ("EHV") system (500 kV and above) are shared by all PJM members, but that under PJM's current zonal rate tariffs, the cost of AEP's EHV system is recovered principally from load within AEP's transmission zone.

In an Order issued May 31, 2005, the FERC found (as a consequence of AEP's assertions) that PJM's current modified rate design may not be just and reasonable. Consequently, the FERC opened a new docket for the express purpose of conducting a hearing on this issue. Following the filing of pre-filed testimony in this proceeding, a hearing in this docket will be convened in April 2006. The Commission has intervened in this docket. Modification of PJM's rate design could ultimately result in a shifting of costs between PJM regions. For example, a uniform, system-wide PJM rate could decrease costs to customers located in the AEP region and increase costs to customers located in the Dominion region. However, the ultimate impact of a revised PJM rate design on Virginia customers is far from clear given jurisdictional questions regarding state versus federal authority and the existence of capped rates.

<u>Appeal to federal appeals court concerning future rate treatment of DVP's RTO integration and ongoing administrative costs.</u>

The Office of the Attorney General of Virginia and the Commission have taken appeals to the United States Court of Appeals for the District of Columbia from an Order entered by the FERC in FERC Docket ER04-829-000. At issue in this appeal is whether DVP will be positioned to seek recovery from Virginia ratepayers after 2010 when DVP's capped rates expire, of approximately $280 million in RTO-related costs (plus carrying costs) incurred *during* the capped rate period.

In FERC Docket ER04-829-000 (DVP's RTO integration docket), the FERC approved DVP's entry into PJM South by FERC Order dated October 5, 2004. In that docket, DVP specifically requested that the FERC authorize DVP to carry forward on its books of account for future rate treatment purposes, DVP's costs associated with joining an RTO and the annual administrative costs associated with its membership in PJM—all of which occurred or are occurring during DVP's retail capped rate period slated to end at the end of 2010. Costs given this type of accounting treatment by a regulatory body are called "regulatory assets." DVP asserted in its pleadings in this docket that its RTO-related costs are not currently recovered in its capped rates, nor were they intended to be.

Under the FERC's own accounting rules and the FERC's precedent applying them, before the FERC can give a utility the green light for regulatory asset treatment, the

FERC must first determine that (i) such costs are not currently recovered in rates, and (ii) that these costs can be recovered in future rates. DVP explicitly asked the FERC for such a determination as part of its RTO integration petition. However, the FERC declined to make these determinations required under its own rules, but instead authorized DVP to decide for itself whether to book these costs as regulatory assets.

The Commission and the Attorney General first sought rehearing from the FERC on the basis, *inter alia,* that the FERC had violated its own rules and precedent by not making these two specific findings described above. The FERC's March 5, 2005, Order on Rehearing rejected that contention. The Commission and the Attorney General then filed their appeals with the D.C. Circuit, where the matter is pending. The FERC has filed a motion with the Court seeking dismissal of the appeal, which has not yet been heard as of this writing.

Energy Infrastructure

Senate Bill 684, enacted by the 2002 Session of the General Assembly, required the SCC to convene a work group to "… study the feasibility, effectiveness, and value…" of collecting information relative to the location and operation of specified electric generating facilities, electric transmission facilities, natural gas transmission facilities, and natural gas storage facilities serving the Commonwealth. This information encompasses data relative to the electricity and natural gas loads imposed by Virginia consumers and the dedication of facilities to the service of those loads.

The Commission filed its report on November 20, 2002, and presented the results of its work to the CEUR during its December 12, 2002, meeting. The Commission report concluded that the collection of extensive data related to Virginia's energy infrastructure is, in fact, feasible. With regard to the effectiveness and value of such a data collection effort, the report noted that ". . . the electric utility industry is in a state of extreme uncertainty and will likely remain so for the foreseeable future." The report ultimately recommended three options for the CEUR's consideration. The CEUR concluded that the Commonwealth must continue to maintain oversight over the reliability of the electric infrastructure and adopted a resolution on January 27, 2003 ("Resolution"), requesting, in part, that the Commission collect the data necessary to monitor the dedication of generating facilities to the provision of electric bulk power supply in the Commonwealth. The Resolution also requested the Commission to report the results of its work to the CEUR, on or before July 1, 2003, and to provide subsequent reports as the Commission deems necessary or as requested by the CEUR.

The Commission's Report of July 1, 2003, indicated that with the advent of restructuring, electric utilties providing service in the Commonwealth have reduced planned reserve margins and expect to rely largely on the market for the provision of capacity to serve load growth and to provide adequate reserves. The Commission Staff collected and provided updated infrastructure information at the September 8, 2004, CEUR meeting that support these same conclusions. At the present time, the Staff is not aware of significant changes with respect to planned construction of new infrastructure in Virginia.

AEP and Dominion Virgina Power, subsequent to Commission approval, joined PJM on October 1, 2004, and May 1, 2005, respectively. Accordingly, PJM is now the primary driver of generation and transmission reliability planning in most of Virginia. In addition to determining the need for transmission system expansion and upgrade to ensure grid reliability across its system, PJM effectively dictates to each load serving member its required generation reserve margin and certifies generation resources that contribute to reliable PJM capacity reserves. By directly considering the diversity in the timing of the peak demands of its load serving members and the vastness of PJM generation resources, lower generation reserve margins are required to maintain reliable service than if each member company were to perform such planning functions as an independent entity.

Due to concerns that PJM's generation capacity market, as currently structured with its relatively short-term horizon, may not provide sufficient financial incentive to ensure the timely construction of new generation facilities in the future, PJM is currently developing and evaluating a new Reliability Pricing Model proposal to potentially file with the FERC. An additional issue that may receive increasing attention in the future is whether new transmission facities should be constructed to meet economic needs in addition to those facilities constructed for reliability reasons. The Staff has noted significant divergence in wholesale power prices during certain peak load hours between different PJM zones within Virginia, indicative of transmission constraints within the system and raising the issue of the importance of accessibility to lower cost wholesale power.

The Staff continues to monitor PJM committee and subcommittee activities directed at reliability planning.

Access to PJM Market Information

Virginia statutes that govern the regulation of public utilities in general, and the Virginia Electric Utility Restructuring Act in particular, provide the SCC with both the obligation and authority to monitor the workings of wholesale electricity markets that will impact Virginia retail electric consumers. The integration of Virginia's electric utilities into PJM provides the SCC with a unique challenge in obtaining information from PJM and Virginia utilities required to monitor wholesale markets. At this time, it is too early in our evolving relationship with PJM to determine if the SCC will be able to carry out the market monitoring that was envisioned by the General Assembly when the Act was first passed in 1999. To date, the Staff's efforts to work with PJM have met with mixed results.

As an example, note that in order to assess the functioning of wholesale electric markets, it is reasonable for those inquiring to observe the manner and price levels that comprise offers to sell electricity by suppliers into PJM electricity markets. Unfortunately, PJM and many market participants consider such offer data to be "competitively sensitive," rendering that information generally unavailable to public scrutiny. To the extent that such data is available, it can be obtained on the PJM website after a 6-month waiting period. Further, the information is "coded" so that specific behavior of certain plants or certain generating companies are hidden from public view. This general procedure for the release of this crucial data has been approved by the FERC.

In addition, in the general course of business, the SCC is asked by PJM to comment on or otherwise evaluate certain policy initiatives that may be proposed by PJM for inclusion in its electric system or market operations. Other stakeholders may also make proposals, the evaluation of which requires information possessed by PJM. Moreover, SCC participation in various FERC proceedings could benefit from access to information held by PJM. Up to this point, it has been difficult to obtain from PJM at least some of the information that the SCC deems necessary for the SCC to meet its statutory obligations to monitor wholesale electricity markets.

PJM currently has in place a FERC sanctioned process by which state regulatory commissions may obtain confidential information from PJM. As of this writing, the PJM website indicates that only two state commissions (Pennsylvania and Kentucky) have taken the steps necessary to obtain information under this FERC sanctioned process. Several state commissions, including the SCC, are studying the implications of participating in this process. Some state commissions appear reluctant to sign the FERC protocol for obtaining such confidential information.

The SCC has concerns with the FERC approved protocol and how it relates to the SCC's authority to obtain data and information under existing state law. We are also concerned about what data is deemed confidential, who deems it confidential, whether certain data and information will be provided under the FERC approved policy should we participate, and access to data and information that we believe should not be deemed confidential. Data access and general market monitoring issues will likely be important issues to be tackled as our working relationship with PJM evolves over the coming months and years.

OTHER ACTIVITIES AND ISSUES

<u>Default Service Investigation</u>

On July 24, 2003, the Commission issued an Order (Case No. PUE-2002-00645) establishing the provision of default service to retail customers effective January 1, 2004, pursuant to § 56-585 of the Restructuring Act. Until modified by future order of the Commission, the Commission determined that the components of default service include all elements of electricity supply service and directed the incumbent electric utilities to provide default service at capped rates. The Commission noted that such an approach is consistent with the early stage of competitive retail and wholesale market development in Virginia, yet permits the flexibility to accommodate the evolutionary development of a default service model to parallel future market changes.

Section 56-585 E of the Restructuring Act requires that on or before July 1, 2004, and annually thereafter, the Commission determine, after notice and opportunity for hearing, whether there is a sufficient degree of competition such that the elimination of default service for particular customers, particular classes of customers, or particular geographical areas of the Commonwealth will not be contrary to the public interest. The Commission is directed to report its findings and recommendations to the General Assembly and Commission on Electric Utility Restructuring by December 1 of each year.

In both the 2004 and 2005 proceedings (Case No. PUE-2004-00001 and Case No. PUE-2005-00002, respectively) pursuant to this statutory provision, the Commission issued a Final Order finding that there is not a sufficient degree of competition such that the elimination of default service for particular customers, particular classes of customers or particular geographic areas of the Commonwealth will not be contrary to the public interest. Additionally, the Commission found that default service should not be eliminated or otherwise modified at the current time. The Commission determined that these findings would be reported to the General Assembly and the CEUR in the annual report on the status of competition in Virginia.

Earnings of Virginia Investor-Owned Electric Utilities

Each investor-owned utility operating in Virginia with annual revenues in excess of $1,000,000, is required to make an Annual Informational Filing ("AIF") with the Commission. The purpose of these filings is to allow the Commission to, among other things, monitor the earnings generated by currently approved tariff rates. One section of the AIF, referred to as the Earning Test Analysis, assesses current earnings on a regulatory basis by making limited adjustments to the utility's financial records. Staff conducts a review of each filing and prepares a report to the Commission stating its findings. The following chart shows the calendar year 2001, 2002 and 2003 earnings of each investor-owned electric utility based on Staff's review (unless otherwise noted) of the earnings test analysis included in each company's AIF. The earnings reflect the bundled (generation, transmission and distribution) per books Virginia jurisdictional return on common equity earned on a regulatory basis.

	2001	2002	2003
Dominion Virginia Power	9.80%	22.36%	13.26%*
Appalachian Power	9.52%	12.79%	13.96%
Potomac Edison	13.80%	15.12%	10.35%
Delmarva	6.47%	1.96%	4.33%*
Kentucky Utilities	10.76%	14.19%	11.81%*

* Per Company filing; Staff report has not been completed.

Each of the above companies filed financial data for calendar year 2004 during the first half of 2005. Staff has not yet completed its review of the 2004 data. The following chart reflects bundled per books Virginia jurisdictional return on common equity on a regulatory basis as included in each company's AIF.

	2004
Dominion Virginia Power	13.52%
Appalachian Power	6.27%
Potomac Edison	7.46%
Delmarva	7.02%
Kentucky Utilities	10.34%

Appalachian Power Rate Application

On July 1, 2005, APCo filed an application with the Commission for (i) an adjustment to its capped rates and (ii) approval of a methodology for making future such rate adjustments. The application requests approval of a rate surcharge, the "E&R Factor," to recover post-July 1, 2004 incremental costs for environmental compliance and transmission and distribution reliability ("environmental and reliability costs") pursuant to § 56-582 B (vi) of the Code. APCo requested that its proposed surcharges be made effective August 1, 2005, on an interim basis subject to refund. The proposed 9.18% surcharge will collect approximately $62.1 million annually.

The Commission entered an Order for Notice and Hearing on July 14, 2005, docketing the matter as Case No. PUE-2005-00056, setting a procedural schedule, and requiring public notice of the application. The Order denied until further order of the Commission the implementation of interim rates. The Commission requested legal memoranda on the question of whether and under what circumstances the Commission has authority to make any portion of APCo's proposed rates, filed pursuant to § 56-582 B (vi) of the Code, interim and subject to refund. On July 18, 2005, the Old Dominion

Committee for Fair Utility Rates filed its Notice of Participation as a Respondent in the proceeding.

Craig Botetourt Electric Cooperative Rate Application

On February 1, 2005, Craig Botetourt Electric Cooperative ("CBEC") filed an application with the Commission for an increase in base rates. The proposed annual revenue increase of $954,603 represents an increase over current revenues of 23.44%. The proposed increase is due in large part to a new market-based power supply agreement with AEP which increased purchased power expenses by $579,079 annually. On July 22, 2005, CBEC filed a Joint Motion to Approve Stipulation on behalf of the Cooperative, Staff and the OAG (collectively, the "Stipulating Participants"). The Stipulating Participants agreed to, among other things, an annual increase in revenues of $842,754. A hearing was held on July 26, 2005, where several public witnesses made statements and introduced a petition in opposition to the proposed increase with approximately 450 signatures. The final resolution of this case was still pending at the time this report was presented to the CEUR.

Stranded Costs

On January 27, 2003, the CEUR adopted a resolution (the "2003 Resolution") requiring that the State Corporation Commission:

> *By July 1, 2003, present to the Legislative Transition Task Force the work group's consensus recommendations regarding:*
>
> *(a) Definitions of "stranded costs" and "just and reasonable net stranded costs."*

(b) A methodology to be applied in calculating each incumbent electric utility's just and reasonable net stranded costs, amounts recovered, or to be recovered, to offset such costs, and whether such recovery has resulted in or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.

The 2003 Resolution also included Requested Action No. 8, requiring Commission Staff analysis of differing recommendations in the event consensus recommendations were not reached and Requested Action No. 9, recommendations for legislative or administrative action that the Commission, work group, or both, determine appropriate to address any over- or under-recovery of just and reasonable net stranded costs. On March 3, 2003, the Commission entered an Order Establishing Proceeding, docketing Case No. PUE-2003-00062[31] establishing the work group and schedule. The work group held four sessions; however, members were unable to reach consensus on the issues before it. On July 1, 2003, the Commission submitted a Stranded Cost Report, prepared by its Staff, to the CEUR.

Because no agreement was reached during the work group sessions, the report summarized the various party recommendations and provided Staff's analysis of those recommendations. The Staff presented two methodologies to calculate just and reasonable net stranded costs, and Dominion, the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates (the "Committees"), each

[31] See http://www.scc.virginia.gov/caseinfo/pue/e030062.htm .

presented one methodology. Each of these methodologies was summarized in the Commissions September 2004 Report to the CEUR.

The CEUR's 2003 Resolution, in Requested Action No. 3, directed the work group to calculate each incumbent electric utility's just and reasonable net stranded costs as well as recoveries from wires charges and capped rates based on the consensus methodology and file a report by November 1, 2003. However, as pointed out in the Stranded Cost Report, the work group was unable to conduct such analyses without further direction from the CEUR because no consensus methodology was reached by the work group.

After several stakeholder meetings, the CEUR, on January 15, 2004, adopted a draft resolution (the "2004 Resolution") presented by the Attorney General. The 2004 Resolution requests that the OAG report on September 1, 2004, and annually thereafter until capped rates expire or are terminated, certain data related to stranded costs. A portion of the data to be included in the annual September reports is obtained from information filed with the Commission. Staff assisted the OAG by providing technical advise and information necessary to make its report to the CEUR. Specifically, Staff quantifies earnings available for stranded costs recoveries, at various target returns defined by the OAG, for each investor-owned electric utility based on calendar year data. Staff also calculates generation revenues based on each utility's embedded cost of providing generation service at various target returns. The OAG requests calendar year market price and customer usage data from each utility to determine generation revenues that would have been derived from a competitive market. The calculated market-based revenues are compared to the cost-based generation revenues calculated by Staff to determine potential stranded costs. The OAG made its first report to the CEUR on September 1, 2004.

Financial Profile of Virginia's Electric Utilities

Since the electric industry is capital intensive, it is very important that electric utilities be able to raise capital on reasonable terms and at favorable rates. When raising debt capital, a company's credit ratings are a major factor influencing the terms and rates it is able to obtain. The two major rating agencies are Moody's Investors Service ("Moody's") and Standard & Poor's Ratings Services ("S&P"). S&P assigns bond ratings ranging from "AAA" to "D", with a plus (+) or minus (-) added to show relative standing within the major categories. Moody's assigns ratings ranging from "Aaa" to "C", with a modifier of 1, 2 or 3 in each ratings category from "Aa" through "Caa" to show relative standings within the major categories. A bond rated below "BBB-" by S&P or "Baa3" by Moody's is considered non-investment grade or a "junk bond".

The key national trend in 2005 has been a rather modest level of rating activity with numbers of upgrades and downgrades being relatively balanced.[32] Ratings outlooks are an indicator of expected future rating trends. Stable ratings outlooks outnumber negative outlooks by 2 to 1, and only about 8% of outlooks are positive. So the future trend should remain stable but with a negative bias. Standard & Poor's remains skeptical of utilities' forays into non-regulated business pursuits outside of the companies' core competencies. Such activities include merchant generation and energy marketing and trading. Since the beginning of 2005, rating changes have been primarily influenced by

[32] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; May 3, 2005.

regulatory actions and operating performance. For example, regulatory actions supporting credit quality were influential in upgrading the electrical utilities in California.[33]

In the previous two years, four investor-owned utilities operating in Virginia were downgraded, and yet again, another Virginia utility has been affected. This year, Virginia Electric & Power Co. had its ratings downgraded from "A-" to "BBB+" by S&P, as shown in the following Senior Secured Debt Credit Ratings and Outlooks table. This downgrading resulted after a S&P review of regulatory insulation found that the State Corporation Commission has no mandated capital structure for Virginia Power which would require maintenance of a high, minimum equity level.[34] The rating agency regards a mandated capital structure indicative of a pro-active regulatory approach and a necessary control for financial insulation. According to S&P, while there exists a Virginia statute affording some protection for a utility from subsidizing the unregulated activities of a parent, it is only an "after-the-fact" approach unlike a capital-structure control. The one notch lowering of Virginia Power can be attributed to S&P's consolidated ratings methodology that rates legal subsidiaries on par with their corporate parents, in this case Dominion Resources. The idea is that cash is fungible and therefore can be used anywhere within the corporate family to meet debt service obligations. As a result, a financially strong utility, owned by a weaker parent, generally is rated no higher than the parent or the consolidated corporate credit quality.

A continued "back-to-basics" theme has predominated in the U.S. electric industry in response to past balance sheet damage and liquidity crises. The industry's

[33] Ibid.
[34] Standard and Poor's Ratings Direct Research; Research Update: Virginia Power Downgraded; Dominion

repair job has involved disposing of non-regulated assets, cutting capital expenditures, de-leveraging balance sheets, negotiating interim re-financings and more vigorous assertion by state regulatory commissions regarding the operations and finances of electric utilities.

The merchant energy segment of the electric industry has been relatively stable in 2005. A few credit improvements have occurred but have been the result of mostly successful refinancing and strategic asset sales rather from improvements in operating fundamentals. Utilities with merchant exposure are experiencing unsettled cash flows and regulatory uncertainties.[35]

The need for considerable capital expenditures such as to satisfy environmental requirements, construct new generation facilities, and other unanticipated costs are driving the need for regulatory approvals.[36] Rate filings in Florida, Hawaii, Illinois, Kansas, Maryland, Massachusetts, Missouri and Wisconsin could, in the near future, have rating implications. Regulatory actions on issues such as the restructuring of regional transmission systems and incorporation of certain merchant plants of affiliated companies into the rate base will continue to be argued.

Financial flexibility has always been important to electric utilities and an industry that is restructuring needs the regulatory and political stability to attract capital from both lenders and investors. Credit downgrades force companies into making difficult decisions about capital structures and operations.[37]

Resources Rating Affirmed; December 22, 2004.

[35] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; May 3, 2005.

[36] Ibid.

[37] Standard and Poor's Project Finance and Infrastructure Finance; October 2002.

The current ratings for ODEC and each investor-owned electric utility operating in Virginia are listed below. Following the matrix is a brief discussion of the rating agency's rationale for the rating assigned.

Company	Senior Secured Debt / Credit Ratings and Outlooks
	Standard & Poor's Rating/Outlook
Appalachian Power	BBB/Stable
Delmarva Power	BBB+/Negative
Kentucky Utilities	BBB+/Stable
ODEC	A/Stable
Potomac Edison	BB-/Positive
Virginia Power	BBB+/Negative

Appalachian Power – The rating of "BBB" for APCo has remained unchanged from the last report. S&P rates Appalachian Power based on the consolidated credit quality of its corporate parent, American Electric Power Co. Inc. AEP has undergone restructuring in two of its main jurisdictions, Ohio and Texas, and also exited some unregulated operations. It will face a constant cycle of regulatory proceedings among the eleven states in which it operates. Being a mostly coal-based company, AEP will especially face rising costs from environment requirements.

Delmarva Power - S&P rates Delmarva based on the consolidated credit quality of its corporate parent, PEPCO Holdings, Incorporated (PHI). PHI's metrics for funds from operations to total debt and ratio of debt to total capital remain fairly weak but are tempered by an expectation of improvement in 2006 and 2007. PHI began a debt reduction plan in 2003. On a stand-alone basis, DPL has a strong business profile but remains under pressure to lower costs through 2007 while a rate freeze remains in effect in Delaware and Maryland. According to S&P, Delmarva's strengths include its lack of competition, low operational risk, and supportive regulatory environment. S&P considers transmission and distribution to have lower technical and operational risk than generation, and residential customers to be a very stable revenue source.

Kentucky Utilities - Kentucky Utilities' rating is based partly on its direct parent, LG&E Energy Corp., and on its ultimate parent E.ON AG, a German utility conglomerate. According to S&P, KU's current stable outlook is based on low costs, a reasonable regulatory environment, and on E.ON's implicit support to LG&E Energy and its affiliates. Short-term concerns are potential environmental expenditures related to KU's coal-fired facilities and KU's large industrial customer base.

ODEC - The rating of "A" for ODEC has remained unchanged from the last report. Although ODEC is not subject to SCC rate regulation, its 10 members in Virginia that cover about a third of the state's landmass are subject to capped rates until 2010. For the last five years, the service territory for ODEC has had favorable customer growth characteristics and proactive management by ODEC members has successfully addressed increasing demands. Balancing these strengths are a higher percentage (relative to other cooperatives) of debt obligations in balloon maturities and a high percentage (50%) of total energy needs filled under short-term contracts.

Potomac Edison – S&P rates Potomac Edison based on the consolidated credit quality of its parent company, Allegheny Energy, Inc. On May 9, 2005, S&P raised its credit ratings on Allegheny Energy Inc. and its subsidiaries to "BB-" from "B+". The upgrading was a result of Allegheny Energy Inc. lowering its debt profile by proceeds on asset sales, cash flow, and debt to equity conversion. In addition to its lowering of debt, also factoring into the upgrading were cost reductions and management's active involvement in seeking regulatory relief. Taken on its own, the credit profile for Potomac Edison is substantially stronger than that of its parent, Allegheny.

Dominion Virginia Power – In last year's report, DVP was the only investor-owned electric utility in Virginia whose ratings were not equalized with its corporate parent by S&P. However, on December 22, 2004, S&P downgraded DVP's issuer credit rating to "BBB+" from "A-" to match that of its parent, Dominion Resources, Inc. ("DRI"). As mentioned earlier, the downgrading was the result of a review by S&P of regulatory insulation. That review determined the protection afforded DVP from its parent's weaker financial profile was insufficient for its separate rating. Irrespective of the downgrading, reasons cited by S&P for the relatively strong rating of "BBB+" for Virginia Power include its cash flow stability and a reasonably favorable regulatory environment. Countering these positives are DRI's riskier exploration and production ("E&P") operations, commodity price risk exposure, high liquidity requirements for its E&P hedging program, and weak financial profile.[38]

The negative outlook for DRI reflects its negative, though improving, financials. Dominion's decision to leave its proprietary trading program could improve its cash requirements and reduce business risks. Management's decision to focus on its core

[38] Standard and Poor's Ratings Direct Research; Research Update: Virginia Power Downgraded; Dominion Resources Rating Affirmed; December 22, 2004.

business is a positive development. These developments should improve the company's risk profile and S&P might revise the outlook upward in 2005.[39]

Retail Access Pilot Programs

On March 19, 2003, DVP filed an application requesting approval of three retail access pilot programs to begin in 2004. Combined, the three Pilots make about 500 MW of load available to Competitive Service Providers, with up to 65,000 customers from all rate classes eligible to participate. To encourage participation by CSPs, DVP proposed to reduce the wires charge for the length of the Pilots by 50% of the amount approved by the Commission for 2003.

The three Pilots consist of: (i) a Municipal Aggregation Pilot, in which one or more localities may aggregate residential and small commercial customers utilizing an opt-in method[40] and one or more localities may aggregate residential and small commercial customers utilizing an opt-out[41] method for the purpose of soliciting bids from CSPs for electricity supply service; (ii) a Competitive Bid Supply Service Pilot,[42] in which CSPs bid to serve blocks of residential and small commercial customers; and (iii) a Commercial and Industrial Pilot, in which CSPs make offers to individual large Commercial and Industrial customers with demands equal to or greater than 500 kW.

As amended in the 2003 session of the General Assembly, § 56-577 C of the Code of Virginia states:

> The Commission may conduct pilot programs encompassing retail customer choice of electricity energy suppliers for each incumbent electric utility that

[39] Ibid.
[40] The opt-in method requires that a consumer affirmatively choose to participate.
[41] The opt-out method requires that a consumer affirmatively choose not to participate; absent such a decision the consumer will be included.
[42] Originally named the Default Service Pilot. Following discussion with interested parties, the Company revised the name in an effort to minimize the potential for customer confusion.

> has not transferred functional control of its transmission facilities to a regional transmission entity prior to January 1, 2003. Upon application of an incumbent electric utility, the Commission may establish opt-in and opt-out municipal aggregation pilots and any other pilot programs the Commission deems to be in the public interest, and the Commission shall report to the Commission on Electric Utility Restructuring on the status of such pilots by November of each year through 2006.

On September 10, 2003, the Commission issued its Final Order approving the Pilots stating that, "the Pilots are in the public interest and further the goal of advancing competition in the Commonwealth." However, as a result of the failure of the Pilots to attract CSP participation, on January 30, 2004, DVP filed a request to delay the start date of the Pilots for two months while it considered modifications. On February 23, 2004, the Commission granted the extension and required DVP to notify all Pilot volunteers of the delay and to file its proposed modification by April 2, 2004.

DVP filed its proposed modifications, as ordered, on April 2, 2004. Among the proposed numerous modifications, the key component was the 100% wires charges reduction for 2004. For years after 2004, the wires charge reduction would be an amount up to but not exceeding the reduction for 2004. Pilot customers therefore would only pay, in later years, the increment that the later years' wires charges exceed the 2004 wires charges. On May 25, 2004, the Commission issued an Order Approving Revisions.

On August 24, 2004, DVP issued a Request for Bids with the bids due by noon on September 14, 2004. No bids were received. Subsequently, no bids were received on the October, November, and December of 2004 or January and February of 2005 due dates.

As a result of the continued failure of the Pilots to attract CSPs, DVP again filed a request with the Commission to revise the Competitive Bid Supply Service Pilot. Specifically, DVP proposed to permit any pre-qualified CSP to submit bids on any business day, rather than on a specific due date. DVP would then notify other pre-qualified CSPs and permit them to submit a competing bid the next business day. Additionally, DVP proposed to modify the bidding period. Rather than two separate periods as originally approved, DVP proposed one bidding period that would extend through the October 2007 meter reading for participating consumers.

On January 28, 2005, the OAG and Direct Energy filed comments with the Commission generally supporting the revisions. On February 4, 2005, the Commission Staff filed comments stating that, as an attempt to encourage CSP participation in the Pilot, it did not object to the proposed revision relating to the elimination of the established monthly due date for bids. However, the Commission Staff expressed concern that such a revision may be at the expense of conducting a bidding process that will resemble one used for the procurement of default service in the future. The Commission Staff stated that the bidding process for default service will likely utilize a fixed bid date.

On March 3, 2005, the Commission approved the revisions as requested by DVP. Since that time no bids have been received in the Competitive Bid Supply Service Pilot. With respect to the other two Pilots, no CSPs have enrolled any C & I customers and no municipality has indicated definitive interest in participating in the Municipal Aggregation Pilot.

Future SCC Activity

As described in this Report, the basic rules, systems, and procedures are in place to accommodate retail choice. Virginia's electric utilities are now members of PJM, a fully functional RTO. Unless otherwise directed by the General Assembly, the SCC will take the following actions during the next year as part of the effort to facilitate retail access:

- Monitor and analyze the activities and events occurring within the PJM market.
- Continue to explore the potential for designating alternative default service providers.
- Monitor and analyze market prices and the implications for resulting wires charges for incumbent electric utilities, and re-set those values as needed.
- Develop the methodology to determine market-based costs for use in exemption of wires charges and minimum stay provisions.
- Monitor PJM activities regarding reliability planning and relationship to the study related to SB 684 regarding the reliability of our energy infrastructure.
- Continue working with the Office of Attorney General to review stranded costs and associated over or under recovery.
- Continue to solicit ideas from stakeholders about methods to attract CSPs to the Commonwealth.
- Continue to monitor approaches being used in other states to attempt to stimulate competitive activity.
- Reactivate the education of consumers about choice when it appears appropriate, although at a pace that conserves resources.
- Monitor activities within the framework of pilot programs and exemption programs to test our infrastructure for a competitive retail marketplace.

APPENDIX II-A

SUMMARY OF NATURAL GAS RETAIL ACCESS PROGRAMS IN VIRGINIA

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This appendix updates last year's report regarding natural gas retail access programs in the Commonwealth of Virginia. Large natural gas customers in the Commonwealth have been allowed to arrange for their own supply and transportation of gas for more than ten years. Natural gas retail access is now available through two programs, one in the service territory of Washington Gas Light ("WGL"), including customers within the service area of Shenandoah Gas, and the other in the territory of Columbia Gas of Virginia ("CGV").

WGL's Retail Access Program

As of July 1, 2005, WGL's program has twelve CSPs serving 6,997 non-residential customers and four active CSPs serving approximately 56,000 residential customers. Cumulatively, these accounts represent approximately 14.6 percent of the 432,708 natural gas customers in WGL's service territory. It is important to note, however, that WGL's unregulated affiliate, WGES, is serving approximately 82 percent of the non-residential shoppers and approximately 83 percent of residential shoppers. .

CGV's Retail Access Program

As of July 1, 2005, there are four CSPs providing service to 1,988 non-residential customers and 7,370 residential customers. Cumulatively, these accounts represent approximately 4.2 percent of the 221,956 natural gas customers in CGV's service territory. It is noteworthy that the two CSPs serving the greatest number of CGV's customers are non-regulated affiliates.

CSP Activity

The two natural gas retail access programs have provided useful information to utilities, CSPs, consumers, and the Commission Staff. The level of CSP activity has been considerably better in the natural gas programs than has been experienced in the electric programs, although a high level of affiliate market concentration may have distorted the actual level of competitive activity.

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PART III

RECOMMENDATIONS TO FACILITATE EFFECTIVE COMPETITION IN THE COMMONWEALTH

PART III

Recommendations to Facilitate Effective Competition in the Commonwealth

Part III of the Report includes a discussion of comments advanced by various stakeholders as means of facilitating effective competition in the Commonwealth and the SCC's continued actions to implement the elements of the Restructuring Act as soon as practicable.

To assist development of a comprehensive list of recommendations to foster effective competition, on March 17, 2005, the Staff sent a letter electronically to 84 interested stakeholders seeking their suggestions and posted such letter to the Commission's website. Although the Staff's distribution list targeted stakeholders thought most affected by electric restructuring issues, it received only five initial responses and one additional reply to others' comments, included as Appendix III-A to this Report. It should be noted that one of these responses was a joint comment submitted on behalf of three competitive suppliers, thus representing suggestions from a total of 7 entities. In similar surveys conducted in both 2004 and 2003, the SCC received eight and twelve such responses, respectively.

The Commission appreciates the comments it received from those that responded. Although we would have preferred a larger number of participants, we did receive input from of a cross-section of stakeholders: utilities, competitive service providers, and consumer representatives.

Generally, most of the comments received are similar to those expressed in prior years' reports and reiterated during the past year via various forums. Respondents' recommendations do not provide new ideas as all suggestions have already been considered, or are currently under consideration, by the SCC and the CEUR.

Most perspectives indicate a major milestone was reached this past spring as DVP integrated into PJM. This action completed the transfer of operational control of transmission lines to an RTO for the investor-owned utilities as required by the Restructuring Act. After only a few months of RTO operation, it is premature to determine if the anticipated benefits to customers will be realized. Other major issues mentioned in the comments, and considered to be obstacles, include the continued existence of wires charges and the low, capped rates of the incumbent utilities and default rates not yet reflecting market prices.

Although the majority of the responses identify the above concerns, these same entities encourage the continued path of restructuring to facilitate a well-developed competitive retail market in Virginia. The two responses representing consumer interests remain skeptical. The large consumer group cites examples of competitive wholesale markets resulting in significantly higher retail prices. They caution that electric restructuring has not yet worked in Virginia and current expectations do not look promising for the future. Although their concerns are articulated, and they believe a better balance of risks and benefits among all stakeholders is needed, they stop short of suggesting a stop or reversal to electric restructuring. The small customer representative contends that deregulation is not working, will not work in the future, and urges a reversal of direction back to a regulated environment. They caution that competition has been and is likely to continue to be slow to develop and that any opportunity for consumers to save on their energy bills is unlikely.

SCC Assessment

Section 56-596 of the Act requires the SCC to report its recommendations to facilitate effective competition in the Commonwealth as soon as practicable, which shall include any recommendations of actions to be taken by the General Assembly, the SCC, electric utilities, suppliers, generators, distributors, and regional transmission entities the SCC considers to be in the public interest. In last year's report, the SCC noted that passage of Senate Bill 651 by the 2004 General Assembly and approval by the Governor provides legislative direction to continue implementing the Restructuring Act. In the year since the issuance of last year's report, the SCC continues to perform its charge to provide regulatory certainty and put in place the necessary infrastructure to implement restructuring.

The integration of APCo and DVP into PJM on October 1, 2004, and May 1, 2005, respectively, were watershed events in Virginia's transition to a restructured electricity market. At present, virtually all Virginia load is served under the terms and conditions of a FERC approved RTO (PJM) and the wholesale electric market rules that go hand-in-hand with those integrations. While delay in PJM integration was thought by some stakeholders to be a major impediment to the spread of retail competition in the Commonwealth, thus far the integration of Virginia's two largest incumbent electric utilities has not led to greater levels of retail competition.

Virginia traditionally enjoyed relatively low regulated electricity prices. The existence of capped rates along with steep increases in fuel and wholesale electric power costs continue to provide little margin in which alternative suppliers can compete. As past versions of this Report have noted for some time, there is tension between the belief that price caps are a fundamental flaw of the Restructuring Act and the belief that consumers should not be exposed to market-based prices until effective competition has developed and can be depended upon to regulate prices.

The 2004 General Assembly agreed that rate caps are an essential consumer protection built into the Act and chose to continue such protection by extending the capped non-fuel rates for incumbent utilities until December 31, 2010. It also determined that wires charges would expire on July 1, 2007, as originally intended. Since current and expected electricity market prices generally exceed capped generation rates (including fuel costs), wires charges were generally not applicable in 2005 and are not expected to apply in 2006. The current and likely future absence of wires charges combined with the integration of APCo and DVP into PJM have yet to induce any increase in retail competition in Virginia even though these two “barriers” were long stated to be major impediments, at least by certain stakeholders. On the other hand, note that the PJM integrations were relatively recent and future wires charges expectations are just that; expectations that may turn out differently. Though unlikely, the possibility of a return to wires charges in 2006 and the first half of 2007 does indeed add risk, and thus costs, to the provision or consumption of competitive retail services.

In 2004 the General Assembly amended the Restructuring Act to allow a large customer that chooses to take service from a competitive service provider to be exempt from minimum stay provisions or the payment of wires charges. In exchange, any such shopping customer will face market-based costs upon any subsequent return to supply service provided by the incumbent utility. The SCC was charged with implementing these statutory changes. Unfortunately, the SCC proceeding related to these changes has proved highly controversial and time consuming. As such, these changes have yet to be implemented. However, given the amount by which electricity market prices exceed capped generation rates (including fuel costs), it is unlikely that any delays in implementing these provisions have retarded the development of competitive retail electricity markets in Virginia.

Many believe the underlying premise of the Restructuring Act is that a competitive market will result in lower retail electricity prices for all Virginia consumers. Unfortunately, retail competitive activity continues to develop slowly throughout the nation, not just in Virginia or in the Mid-Atlantic region. This is especially true for smaller, mass market consumers. Consequently, a market has not yet fully developed that can be depended upon to govern prices. Many have said that the development of well-functioning competitive retail markets must be preceded by the development of well-functioning competitive wholesale markets. While this may be true, it may also turn out that well-functioning wholesale and retail markets may still result in prices to consumers that are higher than historical prices or higher than what "just and reasonable" prices would have been under continued regulation, either as had been practiced in the past or some close variation thereof. Poorly functioning markets may aggravate the situation, increasing prices to Virginia's homes and business even further.

As the State Corporation Commission continues to monitor the transition to competitive electricity markets, both wholesale and retail, within and without Virginia, it notes some ominous new industry features and trends. Many of these trends are discussed in more detail in the body of this Report. They are as follows:

- The nature of the single price auction as practiced in PJM means that retail prices based on wholesale market results may reflect higher marginal costs (actually, the offer price of the last unit required to meet load) for any period under consideration, as compared to the actual average cost of power charged or potentially charged under regulatory regimes where customers are served from a diverse fleet of generating resources.
- The wholesale price histories as described in the body of this Report indicate large retail cost increases for Virginians should those wholesale prices become the basis for retail rates or prices.
- Some Virginia electric utilities (Craig Botetourt Electric Cooperative, City of Danville Municipal, City of Bristol Municipal) have already had to deal with large price increases necessitated by exposure to current and expected future wholesale market conditions. In addition, the Staff of the SCC has been monitoring the plight of the Eastalco aluminum smelter near Frederick, Maryland. Here, the viability of a major manufacturer is in jeopardy due to an impending shift to market-based electricity costs.
- As Dr. Rose points out in Part I, there is an increasing tendency towards oligopoly in the electric power generation sector. PUHCA repeal may allow further industry consolidation. Basic economic theory indicates that, other things equal, increasing industry concentration will diminish competition and raise prices.
- The Federal Energy Regulatory Commission may soon allow more net cash flow to the generation sector, with such cash flow to be obtained from

consumers via new capacity pricing constructs or relaxed market mitigation rules. The FERC apparently seems to believe that raising the sector's financial returns will lead to a more robust, competitive generation sector that will benefit consumers in the longer run.

- The SCC has long been troubled by the monumental challenge that market monitoring imposes on the PJM MMU, the placement of the PJM MMU inside PJM, the lack of an external market monitor and the difficulty of and delays in getting information from the PJM MMU.

These factors lead us to believe that, after the end of capped rates in 2010, should Virginia's homes and businesses face electricity prices based on, set by or primarily influenced by wholesale electric prices in PJM, prices for electric service could rise precipitously in the Commonwealth. While post-2010 market conditions cannot be known with certainty, based on the best available information at the time of this writing, we believe that post rate cap prices could be significantly higher than today's capped rate levels. At the same time, such higher electricity prices will likely yield extraordinarily high returns to certain base load coal and nuclear fired generating resources that currently serve APCo and DVP customers. To the extent that such base load generating units remain inside the incumbent utility as opposed to being spun off to an affiliate or sold outright to a third party, such generating units will remain subject to Virginia state jurisdiction. As such, it would be possible for Virginia policymakers to mitigate, in a non-confiscatory manner, potentially high retail rate levels. Alternatively, Virginia may face dilemmas similar to that currently faced by Maryland where state policymakers have no good alternatives to deal with the threatened shutdown of the Eastalco plant and the loss of close to 700 well-paying manufacturing jobs, which has been attributed to increasing electricity prices.

APPENDIX III-A

RESPONSES FROM STAKEHOLDERS

APPENDIX III-A
RESPONSES FROM STAKEHOLDERS
CONTENTS

COMMONWEALTH OF VIRGINIA

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STATE CORPORATION COMMISSION
DIVISION OF ECONOMICS AND FINANCE

March 17, 2005

Dear Market Participant:

As directed by §56-596 B of the Virginia Electric Utility Restructuring Act, the State Corporation Commission is preparing its fifth annual report to the Commission on Electric Utility Restructuring ("EURC") and the Governor, to be filed by September 1, 2005. That report will cover three topics: 1) the status of the development of regional competitive markets, 2) the status of competition in the Commonwealth, and 3) recommendations to facilitate effective competition in the Commonwealth.

The Commission Staff is once again soliciting ideas from stakeholders (including electric utilities, competitive service providers, consumer groups, natural gas utilities and business associations) to assist the Commission in developing a comprehensive review of ideas that may be considered to facilitate effective competition. The statutory language in §56-596 B related to this part of the Commission report provides as follows:

> This report shall include any recommendations of actions to be taken by the General Assembly, the Commission, electric utilities, suppliers, generators, distributors and regional transmission entities it considers to be in the public interest. Such recommendations shall include actions regarding the supply and demand balance for generation services, new and existing generation capacity, transmission constraints, market power, suppliers licensed and operating in the Commonwealth, and the shared or joint use of generation sites.

Because of the current status of utility membership with PJM, pending dockets before the Commission, and the continued lack of competitive activity in Virginia, we are not asking any specific questions at this time. Rather, we invite and encourage anyone to take this opportunity to submit in writing any comments regarding national, regional, or Virginia restructuring efforts, policies, activities, or events. We ask that you consider the topics detailed in the statute and provide any recommendations or thoughts you may have regarding them, whether positive or negative.

Please provide your comments to me by May 2, 2005. Such response may be sent as a hardcopy via mail or preferably, electronically as an attached WORD Document at david.eichenlaub@scc.virginia.gov. Such comments will be posted to our website at http://www.scc.virginia.gov/division/eaf/comments.htm. Following such posting, any party may submit additional comments in reaction to those posted, if they so desire, by June 1, 2005. Both the initial set of comments and any supplemental comments will be attached as an appendix to the Commission's September 1st report.

I thank you in advance for your continued participation in this effort.

Sincerely,

Dave Eichenlaub

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Dominion
Virginia Power

May 5, 2005

Dear Mr. Eichenlaub,

Dominion Virginia Power ("Dominion" or "the Company") is pleased to submit our annual comments on the status of electric industry restructuring and competition in the Commonwealth. We hope these comments will be useful to the Staff and to the Commission as you compile your annual report.

While increased market prices during a period of capped rates work against the development of retail competition in Virginia, we strongly believe that the Commonwealth's effort to restructure the electric utility industry is making significant long-term progress. In the short term, the effort is producing substantial savings for Virginia consumers and is contributing to the economic growth in the Commonwealth.

Dominion Integration into PJM

One of the clearest hallmarks of this development was Dominion's May 1 integration into the PJM Interconnection, LLC. At midnight on that date Dominion turned over operational control of its 6,000 miles of transmission lines to PJM, the largest regional transmission organization (RTO) in the United States. PJM will operate Dominion's transmission assets as the PJM South region. PJM manages more than 50,000 miles of transmission lines stretching from Illinois to North Carolina with the integration of Dominion. The PJM service area contains about 168,000 megawatts of installed generating capacity.

The development of RTOs, called regional transmission entities (RTE) in the Virginia Electric Utility Restructuring Act (Restructuring Act), was viewed as a foundation of the Commonwealth's restructuring process by the framers of the law. Section 56-579 of the Act directs all Virginia utilities "owning, operating, controlling or having entitlement to transmission" to "join or establish" a RTO. The commitment to regional transmission was affirmed by the 2003 General Assembly through the passage of House Bill 2453 amending the Act. Dominion's PJM membership was approved by the State Corporation Commission on November 10, 2004, by the Federal Energy Regulatory Commission on October 5, 2004, and by the North Carolina Public Utilities Commission on April 19, 2005.

Integration into PJM will produce significant benefits for the Commonwealth and its consumers. PJM's ability to monitor and control transmission assets across a broad region of the country will enhance system reliability. PJM's ability to respond quickly and effectively to changing grid conditions has been hailed as a key factor in stemming the cascading blackout that affected much of the northeastern United States and Canada in August 2003. PJM's regional planning expertise will enhance reliability by directing improvements across a wide area. Dominion's integration into PJM will also give the

Commonwealth's consumers improved access to a diverse supply of generation, another important step in ensuring relability.

Additionally, Dominion's participation in PJM will promote the development of wholesale and retail competition for the supply of electricity. PJM promotes wholesale competition by eliminating market barriers posed by multiple transmission rates – so-called rate "pancaking." PJM will also give competitive service providers (CSPs) in Virginia increased access to competitively priced generation.

In fact, stakeholders have almost universally viewed the lack of a functioning RTO in Virginia as a prime impediment to competition. The Commission took note of this view in its 2003 report on the status of competition in Virginia:

"Perhaps the most common issue raised among the comments submitted in response to the Staff's letter regards the lack of a fully functional RTO as the major obstacle to active competition."

With Dominion's integration, all utilities covered by the RTE membership requirements of Section 56-579 of the Restructuring Act are now included in PJM, operator of the world's largest competitive wholesale electricity market. The integration into PJM will make the extensive and diverse generating capacity within this market more available to meet the needs of Virginia customers, including those receiving default service after capped rates end on December 31, 2010. Access to this successful and highly competitive market will help fulfill the Restructuring Act's mandate, expressed in Section 56-585.C.1, that "after the expiration or termination of such capped rates, the rates for default services shall be based upon competitive market prices for electric generation services."

Restructuring Already Producing Significant Consumer Benefits

The Commonwealth's restructuring process is already producing substantial savings for Virginia consumers. These savings are even more striking against a backdrop of sharply rising prices for almost all other forms of energy, as well as steep electricity price increases in many other states.

The Restructuring Act has produced these savings through curbs on both base and fuel rates for electricity. Senate Bill 651 (SB 651), passed by the 2004 General Assembly, amended the Restructuring Act and froze the provisions of Dominion's fuel factor through July 1, 2007. At that point, the Commission will adjust the fuel rate, based on estimated fuel costs, to run through the end of the capped rate period on December 31, 2010. SB 651 extended the capped rates, originally scheduled to terminate on July 1, 2007, by three and one-half years.

Savings from the fuel factor freeze have been striking. In 2004, the Company reported a fuel under-recovery in Virginia of approximately $201 million. The Company has publicly stated that it expects a similar under-recovery in 2005. It is difficult to quantify exactly how much the fuel factor would have risen in the absence of the freeze. However, the Company earlier this year estimated the adjusted fuel rate would have increased the typical 1,000 kWh residential bill by approximately 8 percent.

The fuel factor freeze was implemented as energy sector market prices rose to record levels. From September 2003 to December 2004, market commodity prices for coal rose by 83 percent, oil by 54 percent, and natural gas by 36 percent, according to the U.S. Department of Energy's Energy Information Administration (EIA). In addition, during the past year, retail gasoline prices in the mid-Atlantic region have increased by more than 42 percent, according to the EIA.

Savings from Capped Base Rates

Potential savings from capped base rates are expected to be even more dramatic. The Restructuring Act capped Dominion's base electric rates at early-1990s levels. Capped rates represented a significant shift of risk from utility customers to shareholders and brought to a halt the base rate cases that frequently occurred on an almost-annual basis. Adjusted for inflation, Dominion's base rates are expected to be about 40 percent lower in 2010, the end of the capped rate period, than in 1994.

In January 2004, a Dominion-commissioned study by Chmura Economics & Analytics found that capped base rates would save the Company's Virginia residential customers as much as $1.8 billion through 2010. This translates into per-customer savings of up to $966 during the extended transition period, according to the study. It also forecast that capped base rates would generate about $307 million in additional economic activity in the Commonwealth.

The Restructuring Act has imposed base rate stability during a period of rising costs for utilities. According to the U.S. Department of Labor's Producer Price Index, the price of copper rose by almost 129 percent from December 2001 to March 2005. During the same period, iron and steel increased by about 63 percent; electric wire and cable by more than 16 percent; and transformers and power regulators by about 12 percent.

Virginia's Rate Stability: A Sharp Contrast with Other States

Virginia's rate stability also stands in sharp contrast to the behavior of electric rates in states that have not embarked on restructuring. Since January 1, 2003, utilities in more than two dozen states maintaining traditional cost-of-service regulation have petitioned for or implemented rate increases, often of double-digit magnitude.

The rising rates have been most pronounced in Florida. Florida Power and Light's typical monthly bill for a 1,000 kWh residential customer has risen by 32 percent, from $69.73 in 2000 to $92.01 this year, according to information on the company's web site. Factors specific to Florida have driven many of the increases in the state, such as heavy dependence on natural gas-fired generation and hurricane recovery costs. However, rates have risen sharply in states that do not face these problems.

Georgia Power, for example, in February asked the state's Public Service Commission for a $550 million increase in the company's fuel cost recovery. If approved, the increase would raise the average residential customer's monthly bill by approximately 10 percent, according to the February 17 edition of the *Atlanta Journal-Constitution*. The petition for the higher fuel rate follows a $134 million base rate increase, approved by the Public Service Commission in December 2004. This increase raised the average monthly residential bill by approximately 4 percent. Also in Georgia, Savannah Electric and Power Company has requested a base rate increase that would raise the typical monthly residential bill by about 8.8 percent, according to a company news release. The petition is now before the Public Service Commission.

In Kentucky, the Public Service Commission in June 2004 approved base rate increases for both Louisville Gas & Electric Co. (LG&E) and Kentucky Utilities Co. (KU). The increases raised LG&E's average monthly residential bill by 8.9 percent and KU's by 6.4 percent, according to a Public Service Commission news release.

Wisconsin has also seen an upward spiral of electric rates, affecting virtually every part of the state. Some utilities have applied for – and been granted – multiple rate increases. The adjustments have raised both base and fuel rates, occasionally by double-digit figures. As an example in Wisconsin, Wisconsin Public Service Co. (WPS) just this month applied for an 11.4 percent base rate increase and We Energies recently applied for a $115 million fuel rate increase. If approved, this would raise the average monthly residential bill by about 4.8 percent, according to the company. Further the company warned customers to expect rate increases averaging 3 to 4 percent annually during the next few years.

These increases, and those in many other states maintaining traditional regulation, bear out the warning made by the respected trade publication *Public Utilities Fortnightly* in April 2004. *Public Utilities Fortnightly* warned of impending "sticker shock" due to utilities petitioning state utility commissions for the rate basing of billions of dollars of improvements, including new generation and environmental upgrades. (Richard Stavros, "Sticker Shock," *Public Utilities Fortnightly*, April 2004, pages 4-5)

Since that article appeared, soaring fuel prices have exacerbated pressure to raise rates. But the Restructuring Act continues to protect Dominion's retail customers in Virginia from these factors.

Promotion of Energy Reliability for the Commonwealth

The Restructuring Act, particularly the 2004 amendments incorporated in SB651, is also working to promote a high level of continued energy reliability in the Commonwealth. Section 56-585.G of the Restructuring Act, added in 2004, encourages development of a coal-fired generating station to serve Virginia utilities' native load and default service customers. The station would utilize Virginia coal and promote the economic development of the Commonwealth's coal-producing regions. On February 24, Virginia's leading electric utilities announced formation of a consortium to explore the development of the facility in Southwest Virginia. Consortium participants include Dominion, Appalachian Power, Old Dominion Electric Cooperative, the Virginia Municipal Electric Association, and the Blue Ridge Power Agency. The non-binding agreement is an expression of the utilities' interest in exploring the development of the project and does not commit them to participating in construction or operation. Dominion will undertake, on behalf of the consortium, the initial development activities for the station, which is expected to cost approximately $1 billion. The possible timeline announced in February included a construction start in 2008 and commercial operation in 2012.

Retail Competition Development in Virginia

The sharp upward movement in energy market prices, including wholesale prices for electricity, has slowed the development of retail competition in Virginia. Market prices were so high, in fact, that Dominion determined most of its customer classes would incur no wires charges during 2005. After making this determination, Dominion waived its right to collect wires charges from any customer classes this year, while reserving the right to impose them in the future.

Even in the absence of wires charges, CSPs have found it virtually impossible to make competitive offers that undercut the capped rates. This situation has also worked against Dominion's retail pilots, despite the Company's efforts to revise them. However, if market prices should decline, the Company believes the changes made in the pilot programs during the past year will make it easier for CSPs to make attractive offers to customers.

For example, the Company has dropped the monthly bidding cycle from its Competitive Bid Supply (CBS) pilot. Instead, CSPs may now submit bids on any business day; this change enables them to move quickly when market prices become favorable. If a CSP submits an offer, other CSPs would have the opportunity to submit competing bids the next business day and the original CSP would have a chance to refresh its offer. The Company also modified the bidding period for the CBS pilot. Under the revisions, there will be one bidding period, extending through October 2007, instead of the two initially proposed. The Commission approved these revisions to the CBS pilot in March 2005.

Interestingly, up until early 2004, only three CSPs had completed licensing to do business in the Commonwealth and had registered with Dominion Virginia Power. Currently, there are six suppliers that are licensed in Virginia and registered with Dominion Virginia Power, with an additional five that are licensed to do business in the Commonwealth but have not completed registration with the Company. Three other suppliers have shown significant interest in restructuring in the Commonwealth and have filed comments in several applicable regulatory proceedings before the Virginia State Corporation Commission. In terms of aggregators interested in opportunities in Virginia, currently there are five entities that have completed both the licensing and registration processes. An additional seven companies are licensed to do business but have not completed the registration process. Clearly, suppliers and aggregators are monitoring progress in the Commonwealth, and are getting ready to move when market conditions are more favorable.

The Company has actively pursued its municipal aggregation and commercial and industrial pilots. Here again, high market prices have proved a barrier to any competitive activity. Dominion, however, has worked with several cities and counties considering participation in the municipal aggregation pilot. During 2004, the Company commissioned a study of the feasibility of six interested municipalities participating in the program. The local governments selected Buckeye Energy Brokers, Inc., an Ohio firm with wide experience in municipal aggregation, to conduct the study. In its report, Buckeye Energy Brokers found it was "very likely" participating municipalities could reach agreements with competitive suppliers that would save money for consumers. The report also termed the pilot "an excellent program...that appears feasible to implement." (Page 1 of the Executive Summary)

Dominion has actively supported the Commission's efforts to implement the wires charge and minimum stay exemption programs authorized by SB 651. We submitted our compliance filing for the two programs on January 10, 2005. The Company's proposed wires charge exemption program included a provision allowing participants who enrolled with a CSP during 2005 to return to capped rate service after their October 2007 meter reading date. This provision was designed to address customer and supplier concerns that the risk of waiving the right to capped rates forever outweighed the benefits of participating. We urge the Commission to complete action on the implementation of the SB 651 programs as soon as possible, as the Restructuring Act calls for the expiration of all wires charges in little more than two years – on July 1, 2007. Without such implementation in the near term, the opportunity for success of the wires charge exemption program will quickly disappear.

A decline in market prices would make successful offers from CSPs much more likely, especially since competitors now have improved access to generation supplies through Dominion's PJM membership.

In conclusion, the implementation of restructuring continues to make substantial progress in the Commonwealth. All incumbent utilities, subject to the RTE provision of the Restructuring Act have now joined PJM. This fulfills a core requirement of the Act and enhances reliability while providing access to a robust wholesale market. Consumers are seeing significant benefits through the capped rates and the frozen fuel factor in a period when prevailing costs that would have driven rates upward under traditional ratemaking are rising significantly. Another consequence of the stability provided by these capped base rates and frozen fuel factor, however, is that it will be very difficult for CSPs to make attractive offers of savings to customers if prevailing wholesale market prices remain elevated. As a result, the number of customers that switch to a CSP can be reasonably expected to remain at relatively low levels during the capped rate period. The number of customers that have switched to a CSP should not be used to measure the success of electric restructuring in Virginia or elsewhere. This expected state of affairs also should not be misconstrued as a failure of restructuring in Virginia, but given the constructs of the Restructuring Act, viewed positively as a reasonable and acceptable position at this stage of the transition toward a fully restructured electric industry in the Commonwealth.

If we can be of further assistance as you develop your annual report, please let us know.

Sincerely,

E. Paul Hilton

E. Paul Hilton

WPS ENERGY SERVICES, INC.

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April 29, 2005

David R. Eichenlaub
Assistant Director, Division of Economics and Finance
VA State Corporation Commission
P.O. Box 1197
Richmond, VA 23218-1197

Dear Mr. Eichenlaub:

Thank you for the opportunity to offer comments for input to the annual report to the Governor. WPS Energy Services' comments are listed below.

Cure for Market Power

Deregulated states need a structure that limits abuse of market power by utilities and their affiliates. This includes divestment of generation by statute (state law), a requirement for full corporate separation by affiliates, a strong code of conduct that is strictly enforced, and true rate unbundling. We have seen in other states that when full divestment is not enforced a dampening of competition results. Also, a code of conduct is worthless if it is full of loopholes and/or is not enforced.

True Rate Unbundling

Incomplete rate unbundling allows utilities to collect on charges that a customer would also pay to their supplier. This leads to a customer paying twice for the same service. A true unbundled rate would eliminate duplicate charges. States need to provide regulations that allow shopping customers to avoid all generation and transmission related utility charges that are already included in supplier rates.

Standard Service Auction

An auction for standard offer service or provider of last resort service encourages a true market. Auctioning off standard offer service provides a market-based rate for suppliers to compete against. Customers no longer subsidize utility rates that are below the market. Utility tariff rates are difficult for suppliers to compete against while customers in the end pay the market price through riders and stranded costs to the utilities. A true market based rate for suppliers to compete against provides real savings to customers.

Municipal Aggregation

Opt-out municipal aggregation has been a success in Ohio. Aggregation allows municipalities to negotiate electric and natural gas rates on behalf of their residents and small businesses. This offers individual consumers an opportunity to receive a lower price than they typically would be able to negotiate on their own. In addition, municipal aggregation attracts suppliers by allowing them to purchase electricity on a greater scale. This ensures a supplier more customers and greater supply certainty for the purchase than individual sign-ups. Thus making it possible to offer lower prices to residential customers and small business customers.

In Ohio, opt-out municipal aggregation accounts for the majority of consumer shopping on the electric side.

Measurable Market Development Periods and Goals

Market development periods need solid end dates and goals that don't change mid-stream. This allows suppliers to plan and offer the greatest savings. It reduces customer and supplier risk when shopping or purchasing supplies. If a supplier knows the rules of the game aren't going to change mid-way through the market development period the market becomes more attractive and higher savings are possible.

In addition continuing market development periods beyond their initial end dates with different rules and requirements becomes costly for both suppliers and customers. In Michigan for example, there was a drastic drop in customer shopping due to changes in the rules mid-stream. There needs to be certainty for deregulation to be successful.

Pilot Programs can help jump start the competitive market and increase consumer education. When properly implemented these programs can be beneficial. Voluntary enrollment programs and shopping credits have been helpful in other states for attracting competition and educating customers on their options.

Purchase of Receivables Requirements and/or Disconnect for Supplier Charges

In Ohio early, the payment priority rules created large arreages for customers and suppliers. Initially, the payment priority in Ohio was utility past due, utility current, supplier past due, supplier current, and then other charges. When a customer paid their bill even a day late their full payment for that bill would go to the utility charges on that bill plus the utility charges for the current (following month's) bill. This left the supplier without payment and thus the charges would accrue and continue to accrue as long as the customer continued to pay late. This created customer confusion and frustration. Customers were paying their bills yet the supplier received none of the money. As a result, many customers were sent to collections for non-payment. A simple solution to this problem is to require utilities to purchase supplier receivables. This provides one point for collection dollars and less confusion for customers on how their money reaches the supplier. In Ohio, the problem lead to expensive litigation and an eventual stipulation that changed the payment priority to utility past due, supplier past due, supplier current, utility current, and then other charges.

New generation should not be built on the back of ratepayers

Utilities should be required to completely divest their generation assets. Also ratepayers should not pay for any new generation. In particular, those customers who shop and are receiving their generation from an alternate supplier should not have to pay for utility generation they never use. Utilities receive full payment for the cost of the generation and then receive returns by selling it on the market. This creates a situation where ratepayers receive no benefit from something they paid for.

Excessive Utility Charges

Utilities in many states have implemented excessive customer switching, customer list, and billing fees in order to limit or avoid competition in their territories. The SCC should monitor utility charges to ensure these charges are in line with actual utility costs. In addition, for many of these items (once the initial set up costs are recovered) the costs to provide the service should be reduced. There needs to be a process to monitor these charges to avoid excessive utility charges, which hamper competition.

Thank you again for the opportunity to comment. Please contact me if you have any questions or would like clarification on any of these items.

Sincerely,
Teresa Ringenbach
Account Manager
WPS Energy Services, Inc.

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May 6, 2005

By E-Mail

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Re: State Corporation Commission 2005 Report To Governor Warner And The Commission On Electric Utility Restructuring On The Status Of The Development Of Regional Competitive Markets And Recommendations To Facilitate Effective Competition In The Commonwealth As Soon As Practical

Competitive Stakeholders' Comments on the Status of Regional Competitive Markets and Recommendations of to Facilitate Effective Competition in Virginia

Dear Mr. Eichenlaub:

In conjunction with the preparation of the State Corporation Commission's ("Commission" or "SCC") 2004 report ("2004 EURC Report") to Governor Warner and the legislative Commission on Electric Utility Restructuring ("EURC"), an *ad hoc* coalition of retail companies submitted comments on the status of the developments of regional competitive markets, and recommendations to facilitate effective competition in Virginia as soon as practical.

Last year's comments reflected the commitments of many stakeholders to viable competitive wholesale and retail electricity markets in the Commonwealth of Virginia, and urged the Commission to facilitate the process towards fully competitive retail and wholesale electricity markets by completing its review of the applications then pending for the integration of incumbent electric utilities with a Regional Transmission Organization ("RTO").[1] The comments also called for a re-commitment from stakeholders to strive for the successful development of competitive markets in Virginia, based upon the firm belief that continued restructuring is in the best interests of the consumers in the Commonwealth.

[1] The Code of Virginia, §§ 56-577, and 56-579, refers to RTOs as "regional transmission entities". These terms may be used interchangeably.

The retail companies identified herein appreciates this additional opportunity to elaborate on those principles from their unique perspectives as potential retail competitors of Virginia's incumbent electric utilities.

The following companies have participated in the development of these comments:

- Constellation NewEnergy, Inc.,
- Direct Energy Services, LLC
- Strategic Energy, LLC

These companies (hereinafter the "Competitive Stakeholders") are united in their belief that the development of effective competition in wholesale and retail electricity markets in Virginia is in the public interest. Moreover, because they focus their businesses on the development of (and participation in) competitive wholesale and retail markets, they offer a unique perspective of the status of competition in Virginia to date, and they have several recommendations for the development of effectively competitive wholesale and retail markets in Virginia.

Pursuant to Va. Code § 56-596 B of the Virginia Electric Utility Restructuring Act, Va. Code Title 56, Chapter 23 (as amended, the "Restructuring Act" or "Act"), the SCC is charged with reporting to the EURC and to the Governor on the status of competition in the Commonwealth, the status of the development of regional competitive markets, and its recommendations to facilitate effective competition in the Commonwealth as soon as practical. The Commission's report is to include any recommendations of actions to be taken by the General Assembly, the Commission, electric utilities, suppliers, generators, distributors and regional transmission entities that the Commission considers to be in the public interest. *Id*. Such recommendations shall include actions regarding the supply and demand balance for generation services, new and existing generation capacity, transmission constraints, market power, suppliers licensed and operating in the Commonwealth, and the shared or joint use of generation sites. *Id*.

In your March 17, 2005 letter to stakeholders ("March 17 Letter"), you state (p.2)

> Because of the current status of utility membership with PJM, pending dockets before the Commission, and the continued lack of competitive activity in Virginia, we are not asking any specific questions at this time. Rather, we invite and encourage anyone to take this opportunity to submit in writing any commentary regarding national, regional, or Virginia restructuring efforts, policies, activities, or events. We ask that you consider the topics detailed in the statute and provide any recommendations or thoughts you may have regarding them, whether positive or negative.

Consistent with your invitation and applicable law, the Competitive Stakeholders offer the following comments and recommendations to assist the SCC in developing a comprehensive review of ideas that may be considered to facilitate effective competition in Virginia.

I. COMMENTS ON THE STATUS OF THE DEVELOPMENT OF REGIONAL COMPETITIVE MARKETS.

A key concern expressed by many stakeholders last year was the lack of progress towards fully competitive retail and wholesale electricity markets as a result of the delayed integration of incumbent electric utilities into an RTO. The comments also called for a re-commitment from stakeholders to strive for the successful development of competitive markets in Virginia, based upon the firm belief that continued restructuring is in the best interests of the consumers in the Commonwealth.

With the May 1, 2005 integration of Virginia Electric and Power Company d/b/a Dominion Virginia Power ("DVP") into PJM, a key milestone was reached in the development of effectively competitive wholesale and retail electricity markets in Virginia. Along with DVP, Appalachian Power Company, Potomac Edison Company, and Delmarva Electric & Power Company are now part of PJM's larger competitive regional energy markets.

While there has not been enough time to gauge the impact on retail competition in Virginia resulting from the participation of these Virginia investor-owned utilities in PJM's competitive markets, experience is showing that regional competitive retail energy markets are developing in the larger PJM region, especially in those areas that have emerged from the transition period to competition. The degree of success in developing competitive retail electricity markets is largely dependent upon the degree to which the retail markets have addressed the following four areas:

1. Access to competitive, transparent regional wholesale markets, such as those administered by PJM;

2. Costs are properly allocated, so that monopoly services (distribution and transmission services) reflect costs, and do not provide a hidden subsidy to the incumbent's competitive generation service;

3. Default rates reasonably reflect market prices, so that boom/bust cycles in retail markets are avoided; and

4. Minimum stay requirements and exit fees are avoided, and are replaced by market-responsive pricing mechanisms.

As examples, Maryland has addressed all these critical elements for large customers, and competition is taking hold. According to the latest information from the Maryland Public Service Commission, almost 65% of large Commercial and Industrial ("C&I") customers are taking service from competitive suppliers, along with 22.5% of Mid C&I, 3.4% of Small C&I, and 2% of residential customers.[2] This competitive activity represents over 2.1 million distribution service accounts, 51, 257 customers, 3250 MW of Demand (peak load obligation), 12,602 MW of total MW Peak Load, and 25.8% of peak load obligation served by competitive suppliers. [3]

The District of Columbia is making progress on all of these elements. Figures for March 2005 show that 11,462 retail customers (5.6%) and 5523 non-residential customers (20.8%) have switched to

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[2] Source: MD PSC website, Month Ending March 2005: http://www.psc.state.md.us/psc/electric/enrollmentrpt.htm.
[3] *Id*.

competitive suppliers,[4] representing in the aggregate 1,381 MW of customer demand (60.5%)[5] and 484,619 MWH (57%) of customer energy usage.[6] However, competition is frozen due to an unexpected order from the District of Columbia Public Service Commission that locked in customers for 12 months to Standard Offer Service. Market participants, however, are united in removing this last barrier, and hope changes will be made in the near future.

In Pennsylvania, Duquesne Light Company has moved into the post-transition period. As of April 1, 2005, 134,609 (22.9%) of its customers are being served by alternative suppliers, representing 1,742.9 MW (42.4 %) of customer load.[7] Other Pennsylvania utilities will be transitioning to market rates through 2011.

In all of these instances, the regulators have moved forward with addressing the need to properly establish default rates that are truly reflective of market pricing.

II. IDENTIFICATION AND FURTHER DISCUSSION OF KEY PRINCIPLES AND RECOMMENDATIONS FOR THE DEVELOPMENT OF EFFECTIVE COMPETITION IN THE COMMONWEALTH OF VIRGINIA.

Notwithstanding the progress in other states, it is unreasonable to expect any significant retail competition to develop in Virginia until several important transition period policies are changed that have erected real barriers to competition. The remaining barriers include items 2, 3, and 4 above:

2. Costs are properly allocated at the end of the stranded cost recovery period (July 1, 2007), so that monopoly services (distribution and transmission services) reflect current costs and load growth, and do not provide a hidden subsidy to the incumbent's competitive generation service;

3. Default rates reasonably reflect market prices, so that boom/bust cycles in retail markets are avoided; and

4. Minimum stay requirements and exit fees are avoided, and are replaced by market-responsive pricing mechanisms.

In addition, the Commission needs to be in a position to re-examine and adjust the allocation of retail supply costs to the supply rates (billing & collection, customer service, account management and other administrative, regulatory and legal costs), so that when the wires charge transition period ends, a more level playing field is created. The present policy is akin to a retail gasoline station (Competitive Service Providers) attempting to compete against a wholesale gasoline terminal (the incumbent electric utility). In addition, it is critical that for retail competition to take hold, the monopoly distribution company not receive a subsidy from competitors by having rates that do not properly reflect costs.

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[4] Source: DC PSC website, Month ending March 2005:
http://www.dcpsc.org/pdf_files/customerchoice/electric/electric_sumstats_no_cons.pdf

[5] *Id.*, http://www.dcpsc.org/pdf_files/customerchoice/electric/electric_sumstats_cons_dmnd.pdf

[6] *Id.*, http://www.dcpsc.org/pdf_files/customerchoice/electric/electric_sumstats_cust_energyuse.pdf

[7] *Id*.

The new exemption programs mandated by Chapter 827 of the 2004 Acts of Assembly ("Senate Bill 651") placed an initial limit on the amount of load [1,000 megawatts ("MW") or eight percent (8%) of a utility's prior year Virginia adjusted peak-load] that could participate in the wires charge exemption program. *See* Va. Code §56-283 E 4.

The original version of Senate Bill 651 as endorsed by the EURC would have allowed all customers the opportunity to purchase electric energy from Competitive Service Providers without paying the wires charge, as long as they were willing to accept market-based pricing if they returned to their utility for generation service. This limitation is fundamentally at odds with the premise of open competition, because it unfairly limits the number of customers that would be eligible to make this choice. It also reduces the likelihood that competitors will be interested in participating in Virginia's retail electricity markets, thus placing increased pressure on default service programs.

To date, the exemption programs have yet to be implemented, so they have produced nothing in the way of customer switching or savings. Every passing day reduces the value of these programs. As a means of stimulating the market, the Commission's next consideration of wires charges should encompass the remaining 18 months of the original capped rate/ wires charge period (i.e., from January 1, 2006 through July 1, 2007), so that customers and suppliers may reasonably evaluate whether to participate in Virginia's retail electricity markets.

Because a wires charge may be applicable for some or all of the period from January 1, 2006 through July 1, 2007, the General Assembly's consideration of potential modifications to the Act in the next legislative session should include an expansion of the exemption programs to all customers that wish to participate. Delaying any potential review of expanding the participation beyond 1,000 MW to 18 months after implementation, and periodically thereafter, perpetuates barriers to CSP entry and consumer participation.

The 1,000 MW limit is insufficient to attract widespread and meaningful retail competition to Virginia, notwithstanding RTO developments in Virginia, given current market conditions and the remaining period during which Virginia's public utilities are permitted to impose wires charges.

DVP and Virginia's other investor owned electric utilities are not imposing a wires charge for 2005. Accordingly, current retail electric rates in Virginia represent the current "price to beat" for CSPs and consumers alike. For CSPs that wish to serve residential customers, 40,000 residential customers (approximately 150 MW of load) represents a minimum critical mass, while a group of 100,000 residential customers (approximately 370 MW of load) represents a preferable tranche size for marketers interested in the residential market. Current market conditions suggest that these levels of customer participation may not produce sufficient economies of scale to encourage meaningful CSP entry and savings for consumers. Increasing the amount of load above 1,000 MW will place less pressure on default service, and may allow the economy of scale to encourage multiple marketers to enter the market and provide service to customers, notwithstanding razor-thin margins.

While the Competitive Stakeholders support all efforts to encourage customer participation in competitive retail electricity markets, Virginia's consumers should be assured of being able to return to capped rates rather than market-based rates at any time capped rates are in place.

Many residential customers and businesses will be reluctant to participate if they give up the right to return to capped rates though 2010 in exchange for a limited opportunity (at most, the period January 1, 2006 to July 1, 2007) to avoid a wires charge. Accordingly, the Competitive Stakeholders recommend that all customers have equal access to the same default service applicable to the customer's class, independent of whether or not customers choose to avail themselves of competitive market opportunities.

III. CONCLUSION.

The Competitive Stakeholders appreciate the opportunity to comment upon these issues related to the development of effective competition in Virginia as soon as practical. The Commission should be encouraged to draw on the experiences in other states in developing competitive options for all customers, including those receiving default service.

The Competitive Stakeholders offer their assistance to help design and promote well-developed, effectively competitive retail electric markets in Virginia, which have been envisioned by the General Assembly since 1999. The Competitive Stakeholders encourage the Commission and the General Assembly to use these recommendations to concentrate stakeholder attention and comments on the goal of facilitating effective competition in the Commonwealth as soon as practical.

Very truly yours,

Thomas B. Nicholson

TBN/tn

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June 18, 2005

To the Members of the State Corporation Commission:
Messers Morrison, Miller, and Christie:

Re: Electric Deregulation

The SCC is due to make its annual report to the Legislative Committee about Sept. 1, and I wish to make the following comments and suggestions:

1. On May 25, Dominion Virginia Power filed its annual report in Case No. PUE-2003-00118 Retail Access Pilot Programs, which showed that much time has now elapsed, and in spite of various manipulations and concessions, no entity has come to Virginia to offer the public or industry any competitive service. All indications are that there will be no such offers in the future.

2. The adverse experience in the Craig-Botetourt Elect. Coop. area illustrates the serious risk to the public. When the rate caps expire the public in Virginia is going to be hurt badly. No benefit from the PJM arrangements is foreseen for Virginia. We are currently faced with big costs if Dominion Virginia Power is allowed to to defer the accounting for the PJM costs until after the rate caps expire.

3. Recent articles in various publications indicate that Virginia has lower electric rates than most areas, and much lower than some in the PJM involved territory. Recent articles have pointed to problems in Texas, which has been cited by some as a pathfinder in deregulation.

4. In August 1992 the SCC issued a 2 volume report pointing out problems, and in Nov. 2002 the SCC issued a lengthy report in connection with 2002 SB 684 which on pages 13-16 documented reasons for concern. Then on Jan 3, 2003, the Commission spontaneously issued a 48 page report entitled "Potential Risks to Electric Service in Viginia" which on pages 31-33 stated there were serious risks and recommended delay and other action to stop deregulation. See also the August 2003 SCC report.

5. The undersigned has been much involved in this legislative and SCC case procedure for several years, and has been on record many times: e.g. see my letter of Jan. 13, 2004, to the Commission on Electric Utility Restructuring, and see my involvement in several major cases before the SCC.

6. The Commission is urged to make a strong report urging the Legislature to review electric deregulation and to take steps to stop and reverse the direction. The subject is complicated by the Federal law, and expertise is required. The SCC has a Constitutional and statutory duty to protect the public.

Urchie B. Ellis
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May 2, 2005

David M. Eichenlaub
Division of Economics and Finance
State Corporation Commission
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Richmond, VA 23219

Re: Comments Concerning the Status of Competition -- Compliance by the State Corporation Commission with § 56-596.B of the Code of Virginia

Dear Mr. Eichenlaub:

Thank you for your letter of March 17, 2005, requesting comments regarding the status of competition in Virginia pursuant to Virginia Code § 56-596.B.[1] We respond on behalf of the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates (collectively, "the Committees"), which consist of large industrial customers of Dominion Virginia Power ("DVP") and Appalachian Power Company ("APCo"), respectively.

In response to prior years' requests of the Commission Staff for comments on the status of competition, the Committees have observed that retail competition for generation services has failed to develop in Virginia. With the exception of a miniscule number of customers purchasing at prices above "capped rates" from a competitive service provider that had stopped offering the service to new customers, there was no retail competition at all.

In terms of the existence of retail competition, little, if anything, has changed; electric competition still has failed to develop in Virginia. Restructuring in Virginia has fallen below expectations in other respects as well, as demonstrated by the attached Report Card on Electric Utility Restructuring, which evaluates progress on key issues related to competition and restructuring. (See Attachment I.) It reveals low or failing grades on the degree of retail competition, prospects for future customer savings from competition, customer rates during the transition to competition, the assessment of stranded costs and benefits (*i.e.*, whether power

[1] Section 56-596.B of Virginia's Electric Utility Restructuring Act ("Restructuring Act"), Va. Code § 56-596.B, requires the Commission to recommend actions to be taken by the General Assembly, the Commission, electric utilities, suppliers, generators, distributors and regional transmission entities that the Commission considers to be in the public interest, including actions regarding the supply and demand balance for generation services, new and existing generation capacity, transmission constraints, market power, suppliers licensed and operating in the Commonwealth, and the shared or joint use of generation sites.

plants are worth more or less than book value), and entry of independent power producers. The only "A" grade is utility earnings. Functioning of a regional transmission entity earned a "C" grade after DVP and APCo finally joined the PJM Interconnection LLC, four years after the original statutory deadline. While "capped rates" may provide incentives for reduced distribution and transmission reliability, that category receives no grade because it is still being assessed.

Virginia electricity customers in communities in the western part of the Commonwealth are feeling the impact of going to market-based rates. With the expiration of wholesale power contracts that supplied their local, municipally owned utilities for years, retail customers in such communities face significant rate increases.

The Federal Energy Regulatory Commission now has ruled in the case involving DVP's request to defer $280 million in estimated RTO-related costs until after 2010, when its "capped rates" are scheduled to expire. Attachment II discusses the case. DVP sought the deferral in order to allow such costs to be passed through to its customers. DVP represented to the General Assembly, however, that the 2004 amendments to the Restructuring Act, which extend its "capped rates" through 2010 and freeze its fuel factor until July 1, 2007, would benefit its customers by imposing on DVP the risks of new costs.

In formulating the Commission's findings regarding the status of competition, and in developing recommendations to the General Assembly, the Committees urge the Commission to consider these comments. Electric restructuring has not worked so far in Virginia, and current developments do not bode well for its future success.

The Committees appreciate the opportunity to comment, and they look forward to continuing to assist the Commission in its response to the mandate contained in Virginia Code § 56-596.B.

Sincerely,

Louis R. Monacell

Edward L. Petrini

#715705

ATTACHMENT I

REPORT CARD
VIRGINIA ELECTRIC RESTRUCTURING

ISSUE	GRADE	COMMENT
Degree of retail competition	F	Retail competition has produced no customer savings. A significant portion of Virginia's retail customers has had the legal right to choose since January 1, 2002. With the exception of a few "green" power sales at prices higher than the utility's capped rates, no supplier has offered to serve retail customers.
Prospects for future savings from retail choice	D	Present market prices and trends suggest that Appalachian Power Comopany's ("APCo's") customers have no prospect for future savings. Dominion Virginia Power's ("DVP's") customers' prospects for such savings are dim in view of the fact that market prices now exceed capped generation rates.
Customers rates during the transition to competition	D	In October 2003, the State Corporation Commission ("SCC") Staff issued its most recent report on DVP's earnings and, in that report, the Staff indicated that DVP's rates are excessive by 10% and would be reduced by approximately $400 million per year if its rates were to be reset based on cost of service. Rates of DVP's customers have soared since the Act passed in 1999 because the Act has permitted rate "adjustments" to reflect increased fuel costs, and such costs have increased. A 2004 amendment to the Act freezes DVP's 2004 fuel factor through June 2007, and customers are paying a lower fuel factor than otherwise would have been the case. Fuel factor savings, however, fall well below the excess found by Staff in DVP's non-fuel rates. APCo customers' rates appear to be only moderately excessive. In April 2005, the SCC Staff issued its most recent report on APCo's earnings. The report indicated a "revenue surplus" of $9.6 million, or about 1%. Further, 2004 amendments to the Act encourage unfair single issue rate increases for APCo without the ability to review the total cost of service to determine whether there are any cost reduction offsets.

Utility earnings	A	DVP's annual report to the SCC for 2003 states that DVP earned a jurisdictional return of 13.26% on common equity. The SCC Staff has not completed its review of DVP's report; however, the 13.26% rate of return exceeds the 9.10% to 10.10% rate of return found reasonable in its review of DVP's prior annual report. DVP has not filed its 2004 annual financial report with the SCC. APCo's Virginia electric business appears to have produced modest over-earnings during 2003, as indicated in the recent SCC Staff report discussed above. The Staff has not reviewed APCo's 2004 earnings.
Assessment of stranded costs and stranded benefits (whether power plants are worth more or less than book value)	F	The Virginia Electric Utility Restructuring Act ("Act") requires an assessment of whether utilities have over- or under-collected "stranded costs" (*i.e.*, costs rendered unrecoverable as a result of restructuring and competition). Despite the likelihood that no stranded costs exist, no such determination has been made. In fact, the existence of significant stranded benefits is more likely. According to the SCC Staff, since DVP's rates were capped by the Act effective July 1, 1999, DVP has earned more than $800 million toward stranded cost recovery, yet no stranded costs may even exist.
Functioning of Regional Transmission Entity (RTE)	C	The Act initially required utilities to join an RTE by January 1, 2001. Neither DVP nor APCo met the statutory deadline. In 2003, two years after the deadline, the General Assembly eliminated the original deadline and enacted a *new* deadline that requires utilities to join an RTE by January 1, 2005, subject to approval by the SCC. Both utilities have now joined the PJM Interconnection, LLC ("PJM").
Entry of independent power producers	D	Generation owned or controlled by DVP and APCo continues to dominate Virginia's generation market. Independent power producers have built little new generation since passage of the Act. In fact, DVP has added to its generation fleet more MWs than the independents. As a result, market power has not been eliminated and possibly has been enhanced.

Reliability of distribution and transmission system	No grade yet	Capped rates could motivate Virginia utilities to decrease expenditures on reliability in order to increase profits and thereby reduce reliability. The SCC, in reviewing utilities' responses to Hurricane Isabel, stated that it appeared that DVP had decreased the number of linemen it employs but that "the Staff has not observed a deterioration in day-to-day operations based on standard measures of performance." Nevertheless, the Staff determined that it was appropriate to conduct an "in-depth audit" of DVP's resources beginning in the fourth quarter of 2004 as a result of "(i) anecdotal feedback from customers and anonymous employees relative to a decline in resources, (ii) the natural incentive to reduce resources within a rate cap environment, and (iii) the belief that any deleterious effects of a reduction in resources might not materialize until years later ..." The SCC staff's audit has not been completed.

ATTACHMENT II

Dominion Virginia Power's Deferral of $280 Million of RTO Costs Until 2011

Dominion Virginia Power ("DVP") urged the General Assembly to amend the Virginia Electric Utility Restructuring Act by enacting SB 651, effective July 1, 2004. It argued that the bill would benefit its customers by freezing their rates at the current level and by imposing upon DVP all of the risks of new costs.

On May 11, 2004, however, DVP and the PJM Interconnection LLC ("PJM") filed with the Federal Energy Regulatory Commission ("FERC") a joint application to establish PJM South and transfer control of DVP's transmission assets to PJM. In the application, DVP asked FERC to permit it to defer approximately $280 million in costs, plus carrying charges, that DVP estimates it will incur from seeking to join and joining a regional transmission organization ("RTO"). DVP argued in the application that it should be entitled to defer such costs and collect them after the expiration of the "capped rate" period in Virginia because "a state imposed rate cap will prevent Dominion from being able to recover any of the RTO-related costs."[1] The "capped rate" period is scheduled to end January 1, 2011. DVP further stated that it should be entitled to defer and collect such costs from its customers because "Dominion is not eligible for any rate cases or any of the aforementioned rate adjustments. It is subject to the rate cap which became effective January 1, 2001, and which now will extend through December 31, 2010."[2]

In FERC's order of October 5, 2004, approving DVP's entry into PJM, FERC stated that it could not determine whether such costs are, in fact, unrecoverable in DVP's current rates or whether they ultimately would be found in a FERC rate case to be recoverable in future rates.[3] Nevertheless, FERC stated that DVP itself must assess all available evidence bearing on the likelihood of rate recovery of such costs in periods other than the period in which they would otherwise be charged to expense under the general accounting requirements for such costs. If DVP determines that it is probable that these costs will be recovered in rates in future periods, then it should record a regulatory asset for such costs.[4]

On March 4, 2005, the FERC denied rehearing of its October 5 order regarding the RTO-related costs.[5] FERC stated that it had made no finding in its October 5 order concerning the "ultimate justness and reasonableness" of the RTO-related costs and that such a finding could be made only in a DVP rate case at FERC. FERC characterized its October 5 order regarding such costs as providing "guidance" on "the proper accounting and recordation of a regulatory asset"

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[1] *PJM Interconnection, L.L.C.*, FERC Dkt. No. ER04-829-000, Joint Application at 20.
[2] Id., Joint Application at 21, fn. 45.
[3] Id. , Order Establishing PJM-South Subject to Conditions, dated October 5, 2004 (slip op. at 21).
[4] Id.
[5] Id., Order Denying Rehearing, dated March 4, 2005 (slip op. at 13).

and as "procedural in nature without prejudice to any party seeking to challenge the subsequent recoverability of these costs in a future rate case."[6]

FERC states that DVP itself, not FERC, must determine the recoverability of such costs in rates in periods other than the period in which they are incurred, and FERC states that DVP must support its determination with "relevant, reliable evidence demonstrating that it indeed meets the criteria for recognition of a regulatory asset … at the time it makes the initial determination, each accounting period thereafter, and when it makes its [rate] filing." [7]

Despite the FERC's assurances in its order on rehearing that it intends only to address the accounting, not the ratemaking, treatment of the RTO-related costs, and that parties may challenge the "regulatory asset" treatment of such costs in a later rate case, FERC's order provides little comfort to DVP's customers. While not a model of clarity, FERC's order on rehearing still permits DVP, not FERC, to determine whether DVP may book the RTO-related costs periodically as a "regulatory asset." By permitting DVP to make such periodic determinations on its own, until its rates are re-set by FERC, the order thus appears to permit DVP to record on its books what may turn out to be an enormous "regulatory asset." When FERC decides the ratemaking treatment of that "regulatory asset" in a rate case, FERC may find it difficult to refuse to recognize such RTO-related cost deferrals in setting rates due to the impact such refusal on DVP's annual earnings.

In any case, DVP should not be permitted to argue to the Virginia General Assembly that it is willing to bear the risk of all new costs during the "capped rate" period and, at the same time, argue to the FERC that, because of the "capped rates," it should be permitted to defer $280 million of RTO costs so that all such costs will be borne by its customers after the expiration of "capped rates."

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[6] Id.
[7] Id.

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June 3, 2005

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Re: Status of Competition -- Compliance by the State Corporation Commission with § 56-596.B of the Code of Virginia

Dear Mr. Eichenlaub:

On behalf of the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates (collectively, "the Committees"), which consist of large industrial customers of Dominion Virginia Power ("DVP") and Appalachian Power Company ("APCo"), respectively, we wish to respond to comments regarding market-based rates for default service.

In particular, Competitive Stakeholders suggest that the degree of success of retail electricity markets is largely dependent, among other things, upon the degree to which retail markets have addressed "default rates [that] reasonably reflect market prices, so that boom/bust cycles in retail markets are avoided."[1] Competitive Stakeholders recommend that the Commission "draw on experiences in other states in developing competitive options for all customers, including those receiving default service," and Competitive Stakeholders mention in particular customers now paying market rates in Maryland, the District of Columbia, and Pennsylvania.

In addition, WPS Energy Services, Inc. ("WPS") states that an auction for "standard offer service or provider of last resort service encourages a true market" and that "[a]uctioning off standard offer serice provides a market-based rate for suppliers to compete against." According to WPS, a "true market based rate for suppliers to compete against *provides real savings to customers*." (Emphasis added.)

In assessing these suggestions regarding market-based rates for default service, the Commission should take into account the experience of a number of communities in the western

[1] Competitive Stakeholders' comments were submitted on behalf of Constellation New Energy, Inc.; Direct Energy Services, LLC; and Strategic Energy, LLC.

part of Virginia in which electricity customers are paying, or will be paying shortly, market-based rates. Retail customers served by municipally owned utilities that are members of the Blue Ridge Power Agency ("BRPA") face significant rate increases.[2] Such utilities have been served at wholesale under seven-year supply contracts with Cinergy; however, with expiration of the Cinergy contracts in 2005, almost all signed new, one-year contracts, based on current market prices, with American Electric Power ("AEP"). The AEP contracts are the result of BRPA's seeking wholesale bids through an RFP process. AEP was the low bidder. Nonetheless, the resulting rate increases for customers served by such utilities are enormous. For example, the largest of the communities, the City of Danville, reports a 78% increase in power supply costs, resulting in the following average percentage increases in rates to its retail customers:

Class	**Average Percent Increase**
Residential	35.3
Churches	20.4
Small general	25.9
Medium general	40.3
Large general	40.2
Lighting	28.0
Average	**36.2**

Other communities reportedly face similar increases.[3] The City of Danville, moreover, expects its base rates to rise still further in 2006, by an average of 4.4%, in order to accommodate cost deferrals and other effects of the increase in purchased power costs resulting from the new contract.[4] In addition, based on proposals recently requested by the City from utilities, prices are ranging 15% to 30% higher than those in the new AEP contract, according to the City, so electric rates may jump again to accommodate higher purchased power costs when the AEP contract expires.[5]

Section 56-585.C.1 of the Restructuring Act provides that, until the expiration or termination of capped rates, rates for default service will be the capped rates. After the expiration of capped rates, the rates for default services shall be the based upon competitive market prices for electric generation services. The capped rates currently are scheduled to expire on December 31, 2010, so customers must pay market-based rates for default service after that

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[2] Municipally owned utilities that are members of the Blue Ridge Power Agency include Danville, Bedford, Bristol, Martinsville, Radford, Salem, and Richland,.

[3] Local newspapers report the following increases, for example: Radford (26-30%); Bristol (40-42%); Salem (approximately 40%); Bedford (41%).

[4] Next year's expected base rate increases are as follows: residential, 3.6%; churches, 3.3%; small general, 2.7%; medium general, 4.2%; large general, 8.1%; lighting, 2.1%. These expected base rate increases do not include the effect of predicted increases in purchased power costs after July 1, 2006.

[5] "More Utility Rate Hikes Expected Next Year," Danville Register & Bee, May 24, 2005.

date. The gap between current market prices and Virginia utilities' capped rates does not bode well for customers, many of whom, depending upon the utility that serves them, could face adverse consequences similar to those being experienced by customers of BRPA members. APCo's "price to beat" for generation and transmission service for jurisdictional industrial customers, according to the Commission's calculation released on December 21, 2004, is 2.9 cents/kWh; current generation market prices, however, are running around 5 cents/kWh, more than 60% higher.

Admittedly, the rate shock experience of retail customers served by BRPA members result from a tremendous increase in wholesale prices as shown by the competitive bidding results in 1997 compared to now. Nonetheless, their experience illustrates that, although wholesale procurement may be done through a competitive bidding process, customers may be forced to pay significantly higher prices. In other words, just as competitive wholesale procurement has resulted in significant rate shock for retail customers of BRPA members, such procurement also could result in rate shock for retail customers of investor-owned utilities when their capped rates end.

In formulating the Commission's findings regarding the status of competition, and in developing recommendations to the General Assembly, the Committees urge the Commission to consider these developments. Electric restructuring has not worked so far in Virginia, and such developments do not bode well for its future success.

The Committees appreciate the opportunity to comment, and they look forward to continuing to assist the Commission in its response to the mandate contained in Virginia Code § 56-596.B.

Sincerely,

Louis R. Monacell

Louis R. Monacell

Edward L. Petrini

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