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

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

Pursuant to Section 56-596 of the Code of Virginia

September 1, 2006

MARK C. CHRISTIE
CHAIRMAN

THEODORE V. MORRISON, JR.
COMMISSIONER

JUDITH WILLIAMS JAGDMANN
COMMISSIONER

COMMONWEALTH OF VIRGINIA

JOEL H. PECK
CLERK OF THE COMMISSION
P.O. BOX 1197
RICHMOND, VIRGINIA 23218-1197

STATE CORPORATION COMMISSION

September 1, 2006

TO: The Honorable Timothy Kaine
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

Mark C. Christie
Commission Chairman

Original signed by

Theodore V. Morrison, Jr.
Commissioner

Original signed by

Judith Williams Jagdmann
Commissioner

TYLER BUILDING, 1300 EAST MAIN STREET, RICHMOND, VA 23219-3630 TELECOMMUNICATIONS DEVICE FOR THE DEAF-TDD/VOICE (804) 371-9206

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Executive Summary and Overview

Over seven years have passed since the Virginia General Assembly passed the Virginia Electric Utility Restructuring Act ("Restructuring Act" or "Act")[1], and only a few years remain 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.

Since the Restructuring Act was enacted into law in 1999, electric utility customers in Virginia have been insulated, to some degree, from changes in electric charges that would otherwise apply in the absence of the base rate caps which are an integral component of Virginia's restructuring program. The presence of those base rate caps, which will remain in place through 2010, has kept retail prices for most Virginia consumers from increasing precipitously despite escalating prices for electricity in wholesale markets. While these retail rate caps will remain in place through 2010, we note that through various provisions of the Restructuring Act, Virginia's electric utilities will have several legally permissible avenues to increase rates between now and the end

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

of 2010. For example, Dominion Virginia Power is authorized to seek yearly changes in rates for fuel costs beginning in 2007, and other Virginia electric utilities, including Appalachian Power and electric co-operatives, may seek rate increases for environmental, reliability, and fuel costs, and two general rate increases, before 2011. Appalachian has already twice applied to this Commission for increases in base rates and Delmarva Power was recently granted a 25% overall rate increase. The Act's ability to protect Virginia's homes and businesses from increases in the market-based price of electricity via the Act's capped base rate mechanism is limited. More Virginia retail customers could see precipitous increases in their electric bills as utilities apply for permitted increases for base and fuel charges prior to the expiration of capped rates on January 1, 2011.

In the past year, retail electric customers in neighboring states have faced precipitous electricity cost increases as applicable rate caps have expired. The controversies generated by the proposed increases have dominated utility news. This Report questions the assertion that new higher rate levels are the result of a well functioning competitive electricity market. However, whether new higher market rates are the result of robust competition or the inappropriate exercise of market power, the basic problem is that today's prevailing wholesale prices are much higher than those envisioned at the onset of industry restructuring. This means that stranded costs are much less than was assumed at the beginning of the transition. While a balancing of the equities remains state and/or utility specific, much of the controversy in Maryland and Delaware arises from the fact that customers paid stranded cost charges set by low market price expectations and now, after paying those stranded cost charges for a number of years, must pay current higher prevailing prices that render, in hindsight, those stranded cost charges unnecessary.

The SCC offers its sixth 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, Consultant and 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.

Part I of this Report contains detailed data and information on restructured wholesale and retail electricity markets around the United States. This year, Dr. Rose has focused on resulting prices and price trends. The economic health of these markets continues to be questionable with little effective competition evident especially for residential and small commercial consumers. Currently, states that have restructured are nearing the end of the respective transition periods with retail prices being determined by market forces. Dr. Rose reports that, in states where the generation portion of the customers' bills is being determined by the market, prices have increased more rapidly than the national average. These restructured states' price increases also exceed those in states that did not restructure. Most non-restructured states remain at prices below the current national average. Thus, the evidence suggests that to date, electricity customers have not received any discernible benefit once the rate caps have expired.

Dr. Rose also presents information regarding his evaluation of recent electricity prices within the wholesale markets. Various factors, including hot weather, natural gas prices, and customer demand, influence electricity prices. Additionally, the frequency that costly generators operate as marginal units to meet load, strongly influences hourly electricity prices.

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 especially for smaller consumers. This national result, when combined with results obtained here in the Commonwealth as detailed in Part II of this Report, continues to question the ability of retail electric competition to provide Virginians with lower prices for electric service than would have prevailed under traditional regulation of the industry.

Part II of the Report focuses on activities in Virginia related to retail access and reviews Virginia specific developments relating to wholesale electric markets and the Federal Energy Regulatory Commission's (FERC) stewardship of those wholesale markets. Almost all of Virginia now resides in the PJM Interconnection "footprint". PJM directs the operation of the regional bulk power system and administers several wholesale electricity markets including those for electric energy, generating capacity and related services. 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. Over the past year, the SCC and its staff sought to obtain data and information necessary to carry out the market monitoring that was envisioned by the General Assembly when the Act was first passed in 1999. To date, our staff's efforts to work with PJM have met with mixed results. Difficulties in obtaining vital data and information leaves the Virginia State Corporation Commission unable to warrant independently that PJM's competitive wholesale electricity markets are effectively competitive.

Part II of this Report 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 continued to implement the Restructuring Act, permitting about 3.2 million electricity customers in Virginia 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 more than 1,300 residential customers and 19 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. The only other supplier activity in the

Commonwealth reflects the recent selection of four large customers in Delmarva's service territory. 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.

Part III of the Report presents comments advanced by a few stakeholders as a means of facilitating effective competition in the Commonwealth. It also includes the SCC's analysis of key industry events occurring since the issuance of last year's report. In last year's report, the State Corporation Commission described "some ominous new industry features and trends." Over this past year, those ominous industry features and trends continued. Part III includes a detailed update on the progression of those trends and how industry restructuring in Virginia has been affected by those trends. Those six trends include the import of the single price auction as practiced in PJM wholesale markets, historical wholesale prices trends, actual impacts on Virginia customers resulting from wholesale market results, industry consolidation, FERC actions, and concerns about PJM market monitoring.

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. Although most parties still agree that a robust wholesale market under an operational and independent regional transmission organization will lead to a viable competitive retail market, experience with PJM over the past year indicates such a marketplace in the Commonwealth continues to be slow to 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
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	Virginia 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
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
MISO	Midwest Independent System Operator
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
NERTO	New England Regional Transmission Organization
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
NYISO	New York Independent System Operator
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

2006 PERFORMANCE REVIEW OF ELECTRIC POWER MARKETS

2006 Performance Review of Electric Power Markets

Review Conducted for the Virginia State Corporation Commission*

Kenneth Rose
Consultant and
Senior Fellow
Institute of Public Utilities
Michigan State University

and

Karl Meeusen
Graduate Research Associate
The Ohio State University

August 27, 2006

*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 Markets

The overall status of state retail access has remained relatively unchanged for several years. 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. Nevada and Oregon allow retail access for larger customers only. Six states that passed restructuring legislation later delayed, repealed, or indefinitely postponed implementation. Twenty-six states are not considering retail access or restructuring at this time and no state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning. A total of 34 states have repealed, delayed, suspended, or limited retail access to just large customers, or are now no longer considering retail access.

At this point, states that have restructured either remain in a transition period or have ended the transition and now have retail prices determined by a market process. To examine state retail market performance, a comparison is made of the retail price trends in restructured and non-restructured states. Figure ES shows the price trends for the states where the transition period has ended for most residential customers in the state by 2005 and where the price residential customers are paying is based on a market process (that is, procurement of power for most residential customers in the state is through bidding, auction, distribution company purchase in the wholesale market, or some other process that secures power for customers that have not selected a supplier). This includes the District of Columbia, Massachusetts, Maine, New Jersey, and New York. Also depicted in the figure is the U.S. average price for residential customers, a combined weighted-average of all states that restructured,[1] and a weighted-average price of the 30 states that remain regulated.[2]

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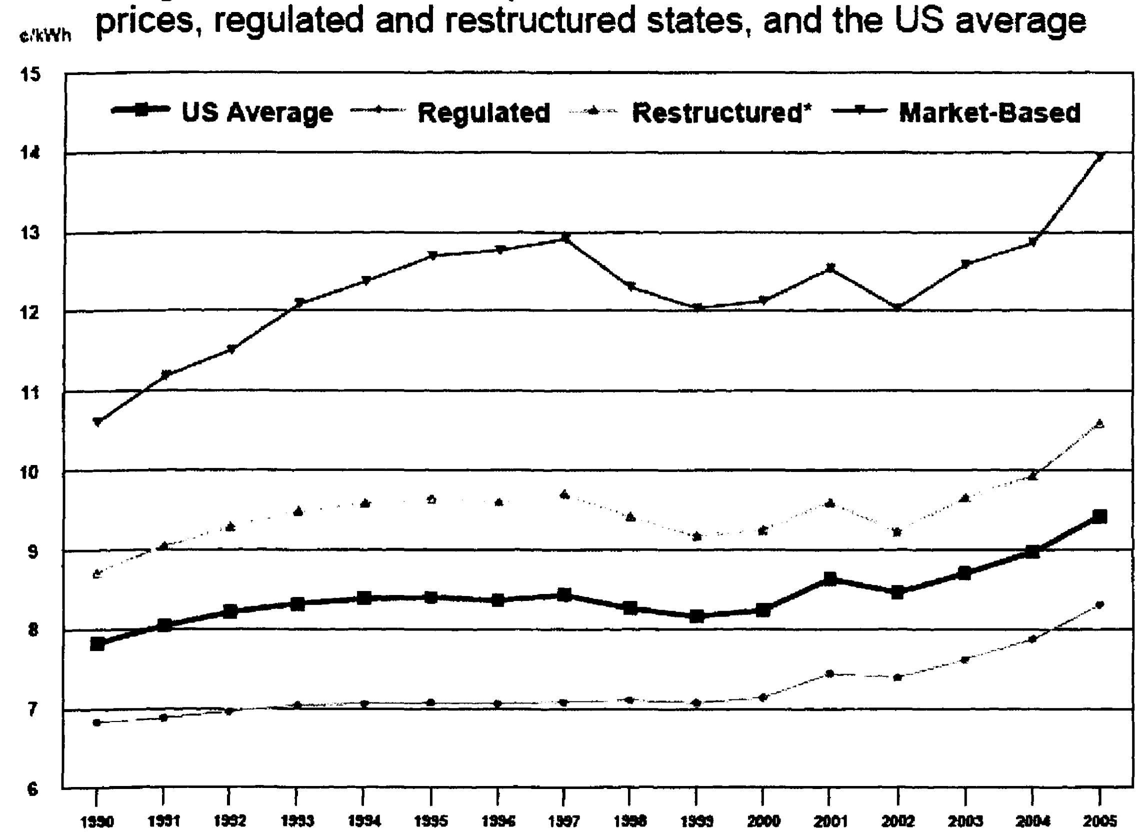
[1]The states included in this group of restructured states are, Connecticut, D.C., Delaware, Illinois, Massachusetts, Maryland, Maine, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Virginia. Excluded are

Figure ES. Residential prices for states with market-based prices, regulated and restructured states, and the US average



*Does not include Arizona, California, and Michigan. Averages are weighted by state residential sales. Data source: DOE/EIA.

All four trend lines show increasing prices in the last few years. The regulated states' prices are moving at about the same rate as the U.S. average between 2002 and 2005. The national average price increased by 11.3 percent and the weighted-average

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California, which suspended its retail access, and Arizona and Michigan, which continue to control utility generation cost.

[2] These states are, Alabama, Arkansas, Colorado, Florida, Georgia, Iowa, Idaho, Indiana, Kansas, Kentucky, Louisiana, Minnesota, Missouri, Mississippi, North Carolina, North Dakota, Nebraska, New Mexico, Nevada (for residential), Oklahoma, Oregon (for residential), South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington, Wisconsin, West Virginia, and Wyoming.

price for regulated states increased by 12.3 percent and the slope of the linear regression line for that period is nearly identical, at 0.31 for the national average and 0.30 for the regulated state average. For the individual restructured states that comprise the market-based states, all, except Maine, increased at a faster rate from 2002 to 2005 than the national average. New Jersey, New York and D.C. were only slightly higher than the national average at 13 percent, 16 percent, and 13 percent respectively. Massachusetts increased by 23 percent during that period.

The prices for the weighted-average restructured states and the weighted-average of the states where the residential customers are now paying market-determined prices increased more (at 14.9 percent and 15.8 percent, respectively) than the U.S. average and the weighted-average of the regulated states, again for the 2002 to 2005 timeframe. The slope of the linear regression line for that period is steeper at 0.44 for all restructured states and 0.60 for the states where the price caps expired. Since many of the states in the restructured group still have some form of price controls, the states where the price controls ended is a better indicator of residential customer pricing under the current restructuring arrangement in those states.

It should be noted that this analysis does not include the impact of the substantial price increases that occurred in 2006, including Delaware and Maryland that ended the transition period this year for most residential customers.

In states where the transition period has ended and the generation portion of the customers' bills have been determined by the market, prices have increased faster than the national average and in states that did not restructure. Non-restructured states and some restructured states still in a transition period generally have increased about the same as the national average. It should be noted too that most non-restructured states remain at prices below the national average.

The evidence suggests that, at least so far, no discernable benefit can be seen for customers in restructured states once the rate caps have expired. Increasingly the evidence is beginning to now suggest that prices for customers in restructured states may actually be increasing faster than for customers in states that did not restructure.

Wholesale Markets

The impact of hot summer weather and the major hurricanes that hit the Gulf States in 2005 (and the subsequent impact on natural gas prices) resulted in the power price spikes that occurred nearly nationwide. The higher natural gas prices of December were also apparent in the country as a whole. During 2004 and early 2005, wholesale power prices above $100/MWh were a rare occurrence. However, in the second half of 2005, wholesale electricity prices over $100/MWh were much more common. For example, at the Mass Hub, 28 percent of the hours from April 2005 through March 2006 saw wholesale prices greater than $100/MWh. This compares to less than two percent at those levels for the twelve months prior to April 2005. Regions such as the Midwest (MISO), and Southeast (Florida, Southern Co.) were seeing wholesale prices over $100/MWh for the first time in several years.

A factor that is often mentioned as having a strong influence on electricity prices is the price for natural gas. However, the hourly power prices and the price for natural gas are not always perfectly correlated. Volatility in PJM electricity prices began *before* the big jump in natural gas prices, which started in September and continued through the year. However, the monthly weighted average PJM price actually began to *fall* through November. This suggests that hot weather was more of a factor than natural gas prices during the summer (when load increases) and fall (when load decreases). Natural gas prices impact electricity prices, but other factors are involved as well.

Clearly, one of those other factors is the frequency that the market price is being determined on the vertical portion of the supply curve. When the wholesale market price is set in this area, during peak hours, the price can climb quickly and to hundreds of dollars per MWh. During peak hours, the demand for electricity increases to a point where the highest priced generation units may be needed to operate to meet the demand. For those hours, the price for all power is set by the highest priced marginal generation units, often units that use natural gas. The PJM Market Monitoring Unit's 2005 State of the Market Report, states that combustion turbine (CT) generation was the marginal unit 23 percent of the time during 2005. This figure 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. Therefore, for over 2,000 hours of the year CT units are determining the price. This has an impact on the overall wholesale price and eventually, on retail customers.

Since generation units that use natural gas are often on the margin, the bid price (not cost) for these units set the market price for that location. However, while natural gas units were 27.5 percent of PJM's installed capacity at the end of 2005, natural gas generated only 5.9 percent of the total generation in 2005 in PJM. *Over 90 percent of the generation during 2005 was from coal and nuclear units.* This underscores the impact of the marginal-bid price determining the market price and its impact on price that retail customers eventually pay.

Electric market characteristics suggest that the market structure is not a robustly competitive one, as was hoped when restructuring began. Because of high supplier market concentration, the difficulty of entry from other firms to build new generation, limited entry from outside the area due to transmission access constraints, and existing market rules, the structure that is emerging more closely resembles that of an oligopoly, where there are only a few firms supplying all or most of the output, than a truly competitive marketplace.[3] There is also an inelastic demand for electricity, particularly in the short-run, since customers have few practical substitutes. All these factors suggest the possibility that market conditions permit suppliers to exercise significant market power.

Coordinated interaction and tacit collusion among suppliers also could have particular relevance for electricity markets. The nearly continuous interaction that suppliers have in Regional Transmission Organization (RTO) markets can allow firms to excise market power and utilize anti-competitive bidding strategies. While transparency is important for markets to perform well, it can have the unintended result of creating

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[3] Market structure issues were discussed in more detail in the 2005 Market Performance Review.

markets that facilitate collusive supplier behavior. A lack of publicly available information impairs the ability to more fully assess market behavior. However, studies have shown that anti-competitive bidding strategies are possible and the 2000-2001 western power crisis demonstrated that it can and does happen. Given the fact that such strategies have been shown to be possible and successful, it is likely that suppliers are currently using strategic bidding techniques and withholding strategies to raise the price, strategies that would be less effective in a more competitive market. These strategies are particularly effective during periods of relatively high demand. RTO market monitors and the Federal Energy Regulatory Commission do not examine markets for possible coordinated interaction and tacit collusion or the impact on market prices.

These are the result of structural characteristics and are an intrinsic part of the electric supply industry. Barring a significant technological breakthrough, appropriate public policy has to be shaped to fit these structural characteristics, and not be based on what works in other industries or on notions of what should work in theory.

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Part A

Results and Update of Electric Power Industry Restructuring Activities

Introduction

This is the sixth 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 U.S. wholesale and retail electric power markets, as required under the Virginia Electric Utility Restructuring Act. Past reports have provided detailed descriptions of the development of the regional wholesale markets and state retail markets. This has 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. Last year's report also offered a perspective on the lessons learned to date from the market results.

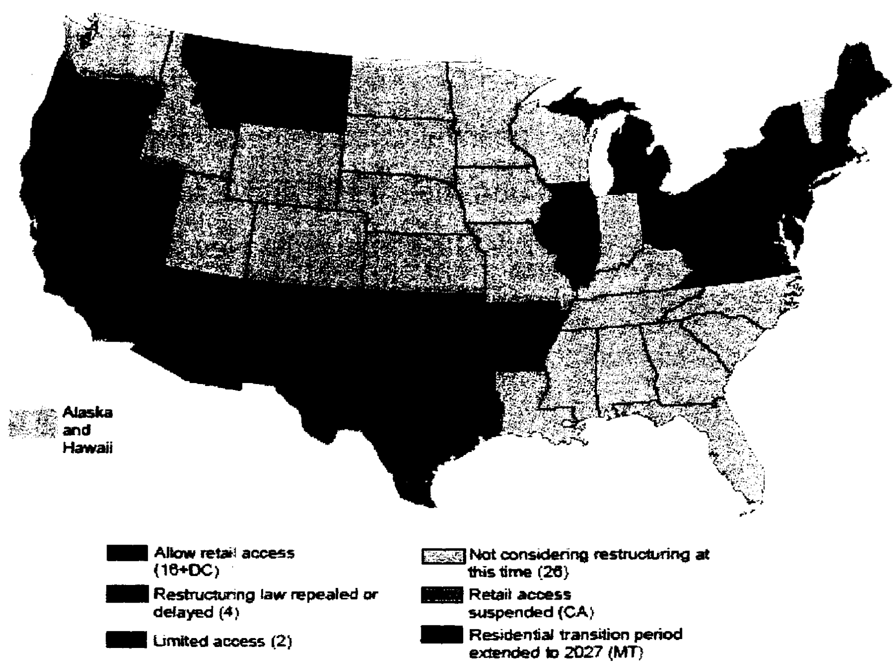
This year's report again provides an overview and update of the wholesale and retail markets. The emphasis this year is on prices. Wholesale prices were clearly significantly impacted by the major weather events of 2005, including warm summer weather in the mid-Atlantic area and Hurricanes Katrina and Rita and the subsequent run-up of natural gas prices. These events had an impact on retail prices as well. This year's report is again divided into two parts. Part A provides an overview of state restructuring activity, retail prices by state, and regional wholesale prices. Part B provides an analysis of restructured state prices compared with prices in states that did not restructure and a perspective on the results of industry restructuring so far and how it relates to the legislative and regulatory goal of fostering the development of competitive wholesale and retail markets.

Retail Markets

National Overview of State Restructuring Activity

The overall status of state retail access has remained relatively unchanged for several years. At this time, as shown in Figure 1, 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 repealed their laws; in September 2001 California suspended the retail access program it already had implemented, more than one year after the beginning of the California and western power crisis. Montana also has been dealing with the severe aftermath of the western power crisis and extended the transition period to retail access for smaller customers to 2027.

Figure 1. Status of State Retail Access



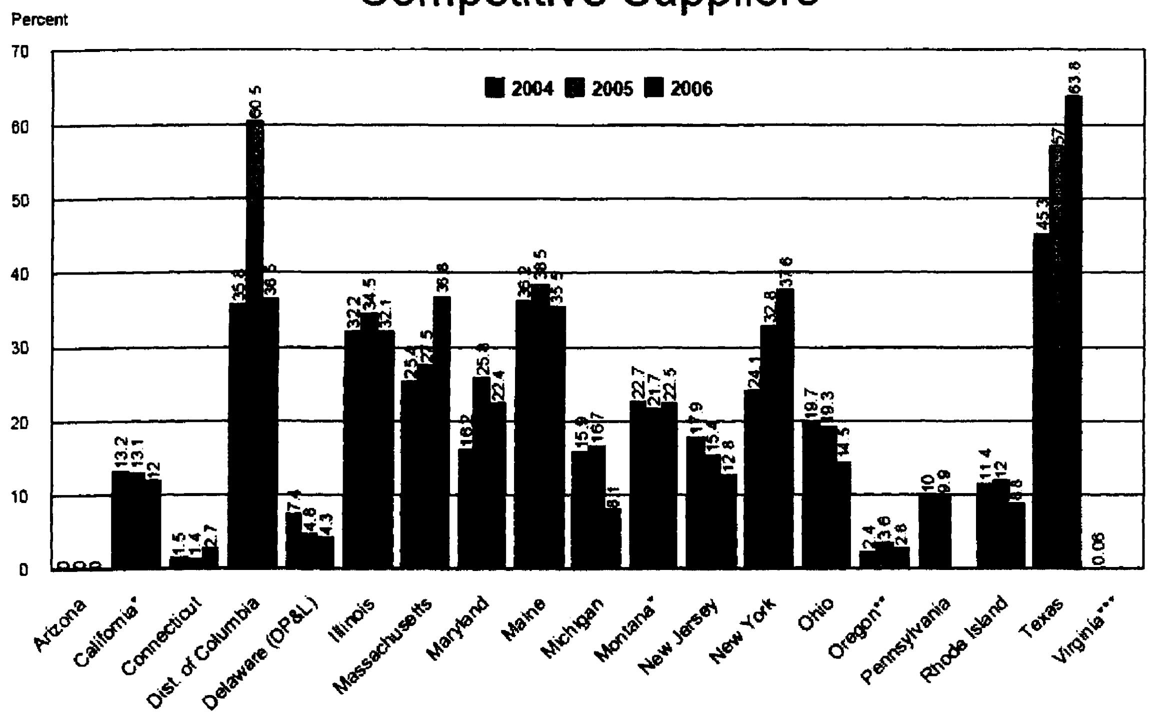
Since the power crisis in California and the West began in mid-2000, no additional states have chosen to adopt retail access. Twenty-six states are not considering retail access or restructuring at this time, and none of these states appear to be working in any meaningful way toward passage. No state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning to take shape. Many states that did not pass legislation were considering it, however, they 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. A total of 34 states have repealed, delayed, suspended, or limited retail access to just large customers, or are now no longer considering retail access.

In addition to 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, and the August 2003 blackout, the most extensive blackout in North American history. This year's significant price increases in several restructured states will likely further discourage any action by states that have not restructured.

Retail Market Activity

Figure 2 shows the percent of the total state electric load that is served by competitive suppliers, for 2004, 2005, and 2006. Five states saw an increase in the percent of total state load served by competitive suppliers in 2006 when compared to 2005, Connecticut, Massachusetts, Montana, New York, and Texas. Three of these states had percentages above 30 percent – Massachusetts, New York, and Texas. Texas had the highest percentage at almost 64 percent of the state's total load and the only state above 40 percent. Eleven states had lower percentages for 2006 than 2005. DC had a considerable decrease from over 60 percent to 36 percent of total load.

Figure 2. Percent of Total State Load Served by Competitive Suppliers

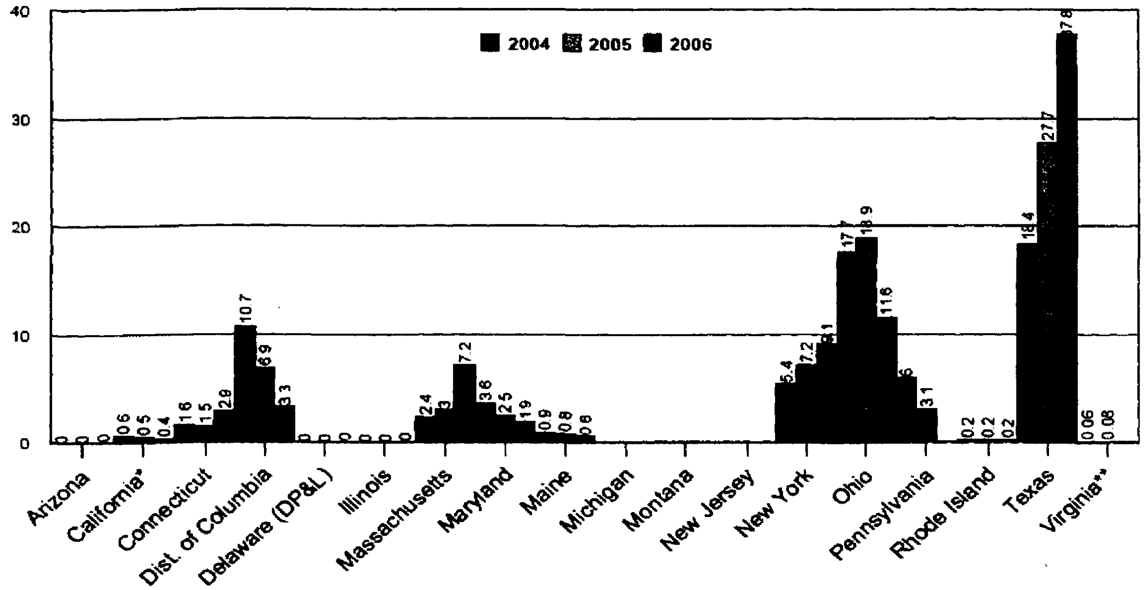


*California retail access was suspended, Montana delayed residential retail access.
**Oregon has retail access for large customers only.
***Virginia percentages are percent of customers, all others are percent of load.
Data Sources: KEMA, Inc., "Retail Energy Foresight," June/July 2004, May/June 2005, March/April 2006 and the Virginia State Corporation Commission.

Figure 3 shows the percent of residential load served by competitive suppliers. Only four states had percentages of the residential load above five percent in 2006, Massachusetts, New York, Ohio, and Texas. Texas was the highest state residential percentage at almost 38 percent of the residential load being served by competitive suppliers. DC and Ohio had significant decreases and many states remain at or very close to zero percent of the residential load being served by competitive suppliers.

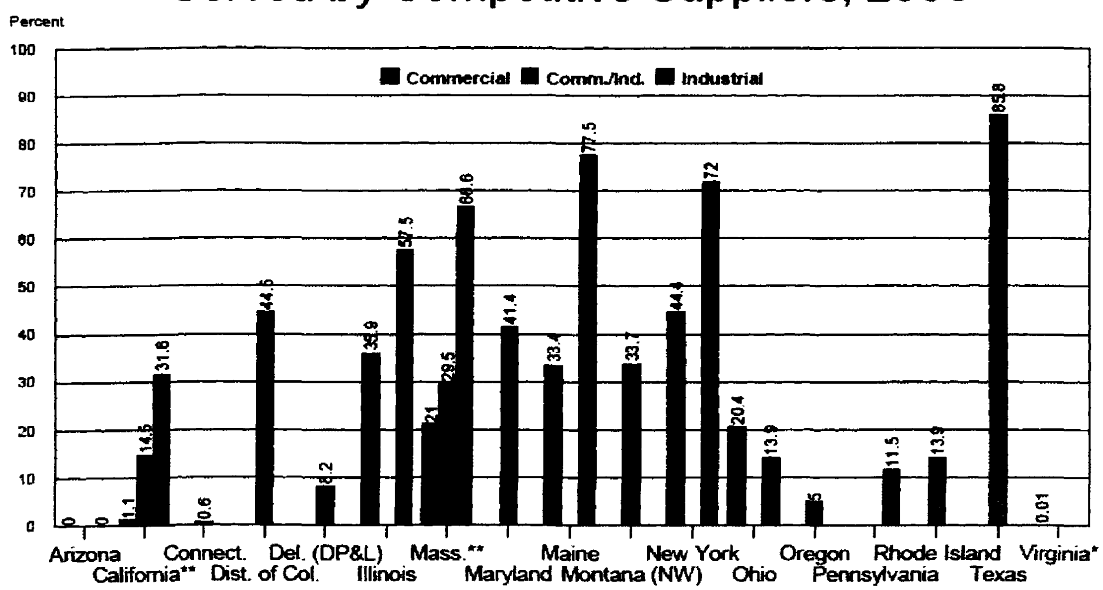
As Figure 4 shows, the overall picture for larger customers is considerably different. Nine states have at least one large customer category above 30 percent of the customer load served by competitive suppliers and five states had a large customer category above 50 percent. Texas had the highest percentage for the large customer categories, at nearly 86 percent of commercial and industrial customers being served by competitive suppliers. Five state percentages were below ten percent.

Figure 3. Percent of Residential Load Served by Competitive Suppliers



*California retail access was suspended, Montana delayed residential retail access.
**Virginia percentages are percent of customers, all others are percent of load.
Data Sources: KEMA, Inc., "Retail Energy Foresight," June/July 2004, May/June 2005, March/April 2006 and the Virginia State Corporation Commission.

Figure 4. Percent of Commercial and Industrial Load Served by Competitive Suppliers, 2006



*Virginia percentages are percent of customers, all others are percent of load.
**For California and Massachusetts, the category shown as "Comm./Industrial" is large commercial.
Data Sources: KEMA, Inc., "Retail Energy Foresight," March/April 2006 and the Virginia State Corporation Commission, 2005.

Retail Prices

This section examines state retail prices by region. To examine retail price trends, data from the U.S. Department or Energy, Energy Information Administration (DOE/EIA)[4] and individual state sources are used and plotted. The DOE/EIA price graphs are in nominal dollars, unless otherwise noted, and are total bundled retail prices reported for the state.

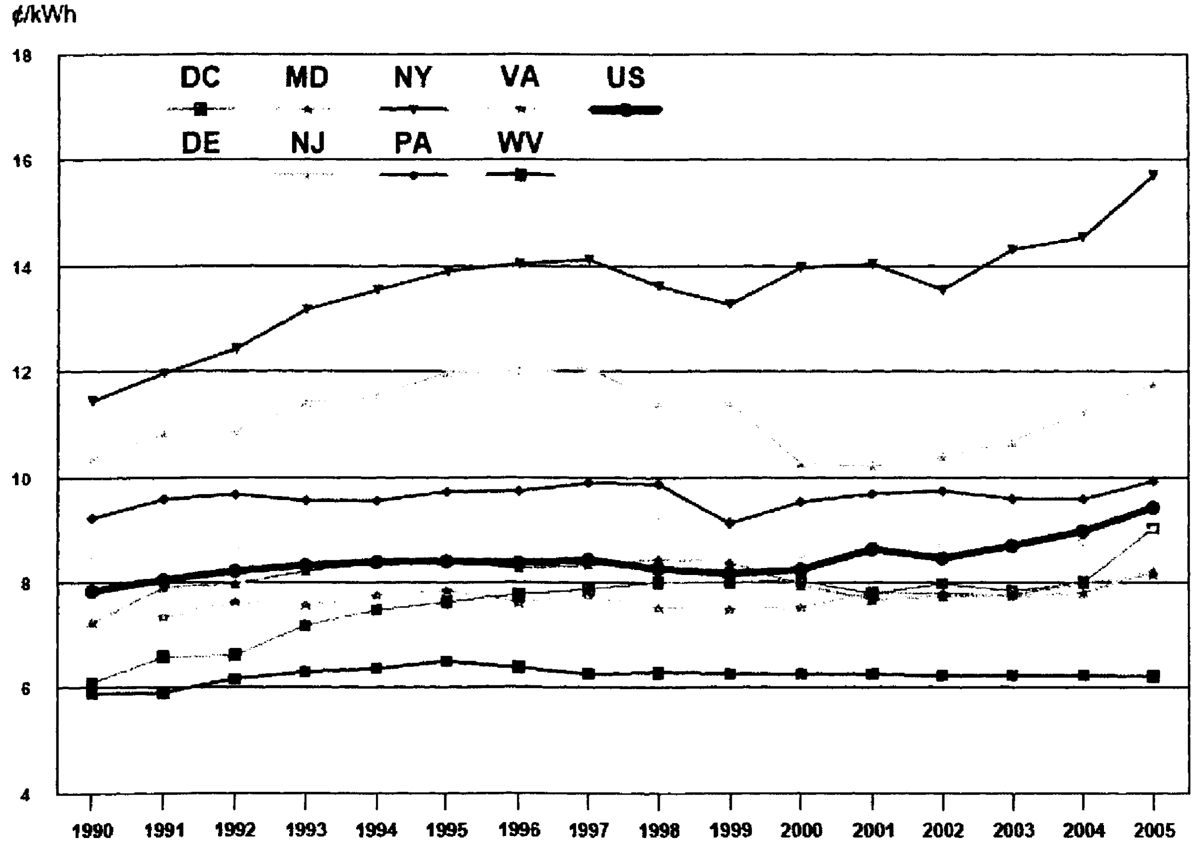
Mid-Atlantic

The U.S. average residential price for electricity has increased over the four years from 2002 to 2005 by 11.3 percent. For states in the mid-Atlantic area, shown in Figure 5, for the same time period (2002 to 2005), four states had increases less than the national average and one fell slightly (West Virginia, by less than one-half of one percent). For these four states, Delaware, Maryland, Pennsylvania, and Virginia, most of the residential customer prices in the state were still controlled during a transition period. West Virginia, the only state in the region to see a decrease for the period, did not restructure its electric industry. Two other states, New Jersey and New York, and the District of Columbia had increases that were greater than the national average. For New Jersey and New York, the increases were 13 and 16 percent respectively. Both of these states have the generation portion of the customers' bills (for most residential customers) determined in the market.[5] DC increased 13.1 percent during this period, 12.8 percent between 2004 and 2005 alone, when the transition period ended in early 2005. (Further details are provided on New Jersey, Delaware, and Maryland below, including 2006 price increases.)

[4] U.S. Department or Energy, Energy Information Administration, Form EIA-826, "Monthly Electric Sales and Revenue Report with State Distributions Report."

[5] The transition period ended August 2003 for New Jersey residential customers. In New York, the transition period ending varied by company.

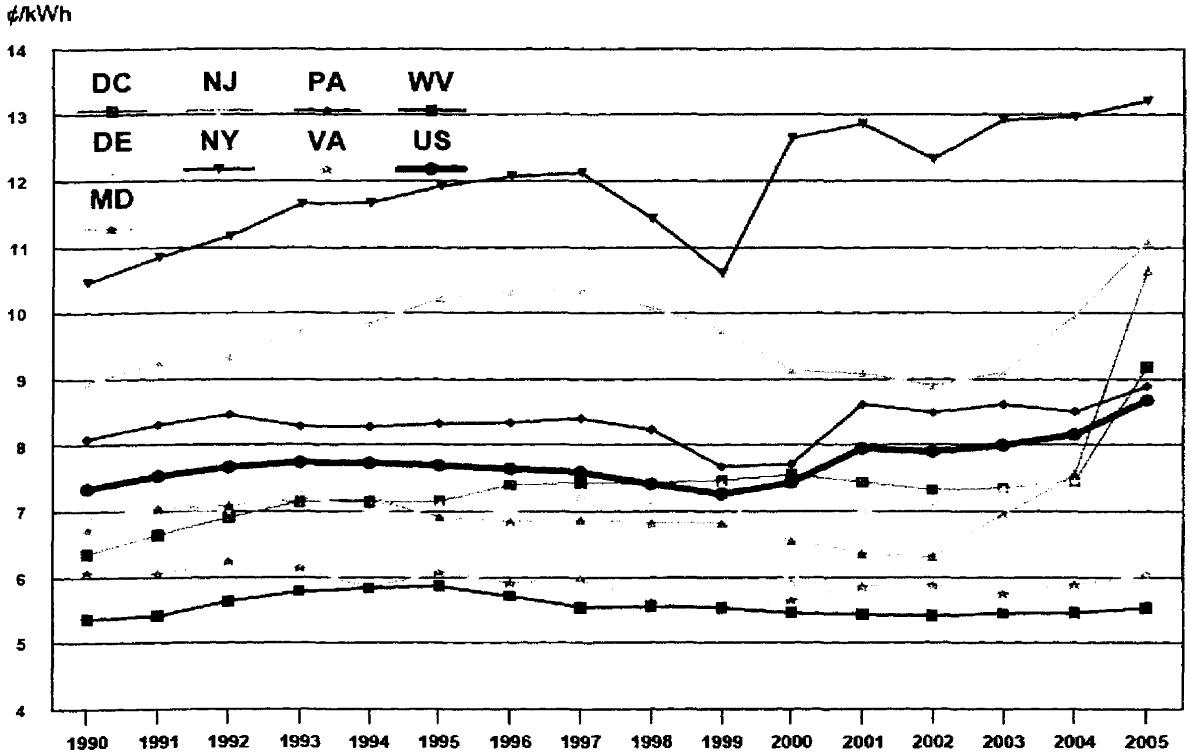
Figure 5. Mid-Atlantic Residential Average Retail Price



Data Source: DOE/EIA

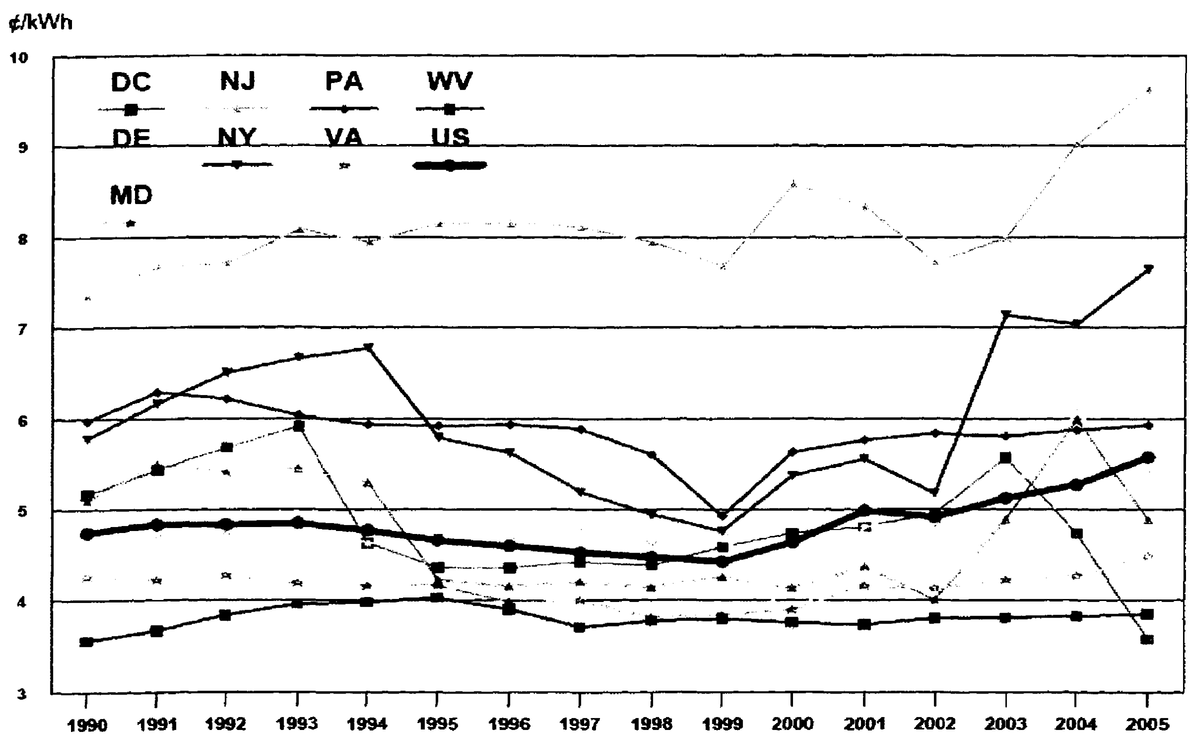
A similar pattern emerges for commercial and industrial customer retail prices in the mid-Atlantic region. Figure 6 shows that commercial customer average prices for the region have also increased significantly, particularly for New Jersey and Maryland customers. For industrial customers in the region, shown in Figure 7, New Jersey and New York have both seen significant increases since 2002 through 2005. The price for DC appears to drop considerably in 2004 and again in 2005. However, this is likely a problem with the DOE/EIA data set's small sample size for industrial customers in a few areas. Examining the data closer reveals that in 1993, EIA reported 156 industrial customers in DC. For 1994 through 2003, they report just one industrial customer, two in 2004, and one again in 2005 (looking at the monthly data for 2005). In contrast, EIA reports over 200,000 residential customers and over 26,000 commercial customers in DC for 2004. Possible explanations may be that there simply are not that many industrial customers in DC to begin with and industrial customers that are present are

Figure 6. Mid-Atlantic Commercial Average Retail Price



Data Source: DOE/EIA

Figure 7. Mid-Atlantic Industrial Average Retail Price



Data Source: DOE/EIA

being served by competitive suppliers that are not being counted sufficiently in the survey. (Moreover, a price below four cents/kWh – or $40/Mwh – is well below wholesale prices in the area in 2004 and 2005. See PJM prices below in this report.) The customer base is much larger for Delaware and Maryland, which also saw a drop in price in 2005 from 2004. This could be reflecting a lower price (however, still higher prices for this customer group than in 2000) or fewer competitive prices being reported – that is, reflecting the loss of utility customers to competitive suppliers and fewer of the competitive prices being reported.[6]

Several states and distribution companies in the mid-Atlantic region have announced significant price increases for consumers in 2006, including, most notably, Delaware, Pike County Light & Power in Pennsylvania, and Maryland. To examine prices in more detail, residential prices in several states and the auctions used to determine residential prices are discussed.

New Jersey

As was covered in previous Market Performance Reviews, the New Jersey Basic Generation Service (BGS) auction is an Internet-based, simultaneous multi-round descending clock auction.[7] The auction determines the generation price and suppliers for customers that have not selected a supplier themselves. The results of the "fixed-price" BGS auctions (for smaller commercial and residential customers) are shown in Table 1. 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

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[6]In Maryland for example, EIA reports a total number of industrial customers in the state at 15,673 in 2004, but 10,573 were utility customers in December of 2004. This suggests about one-third of these customers may be served by competitive suppliers – where the prices may or may not be accurately reflected in the state's aggregate data. A similar pattern is seen for Delaware, having a lower customer base of 561 total industrial customers with 356 being utility customers for December 2004.

[7]A summary of how the auction works and past auction results are in the 2004 Performance Review.

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 and 2006 auctions increased significantly above the 2004 auction prices. 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. The increases from 2005 to 2006 were over 50 percent for all four companies (the percentage increases are shown in the last column of the table). The percent increase from 2004 (36 month term) to the 2006 prices ranged from 83 percent increase for Jersey Central to over a 98 percent increase for Rockland. Nearly all the residential customers in the state receive basic generation service (see Figure 3).

Table 1. Results of the "Fixed Price" New Jersey Auctions (cents/kWh)

	2002 Auction	2003 Auction		2004 Auction		2005 Auction	Percent Increase - 04 to 05	2006 Auction	Percent Increase - 05 to 06
	12 month	10 month	34 month	12 month	36 month	36 month		36 month	
Conectiv/ ACE	5.12	5.260	5.529	5.473	5.513	6.648	20.6%	10.399	56.4%
JCP&L	4.87	5.042	5.587	5.325	5.478	6.570	19.9%	10.044	52.9%
PSE&G	5.11	5.386	5.560	5.479	5.515	6.541	18.6%	10.251	56.7%
Rockland	5.82	5.557	5.601	5.566	5.597	7.179	28.3%	11.114	54.8%

Data Source: New Jersey Board of Public Utilities

The 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. The overall bundled price for residential customers was shown in Figure 5.

Delaware

Delaware passed a restructuring law in 1999 and phased-in customer retail access beginning in October 1999 to April 2001, when all customers became eligible to choose a supplier. As seen in Figures 2 through 4, customers of all retail classes in the state (residential, commercial, and industrial), except for a small percentage of the state's commercial customer load, continue to have their electricity provided by one of the state's utilities that served them before restructuring began. The state's restructuring law also mandated a rate cut of 7.5 percent for Delmarva Power & Light Co. (Conectiv) customers and a rate freeze for Delaware Electric Cooperative (DEC) customers. The cap on rates ended on March 31, 2005, for DEC customers and expired on May 1, 2006, for Delmarva customers. The Delmarva rate freeze was originally set to end in September 2003, but was extended as part of a merger agreement involving Potomac Electric Power (PEPCO) and Conectiv.

Another important feature of restructuring in Delaware, and also in common with many other restructured states, was the transfer of utility generation assets from the state-regulated utility to an entity or entities that are not regulated by the state. In 2002, Delmarva sold or transferred all of its generation assets. Since these assets are now owned by wholesale providers, they are subject to Federal Energy Regulatory Commission (FERC) jurisdiction. The Delaware Public Service Commission continues to regulate the distribution companies and generation that is still owned by state-regulated companies.

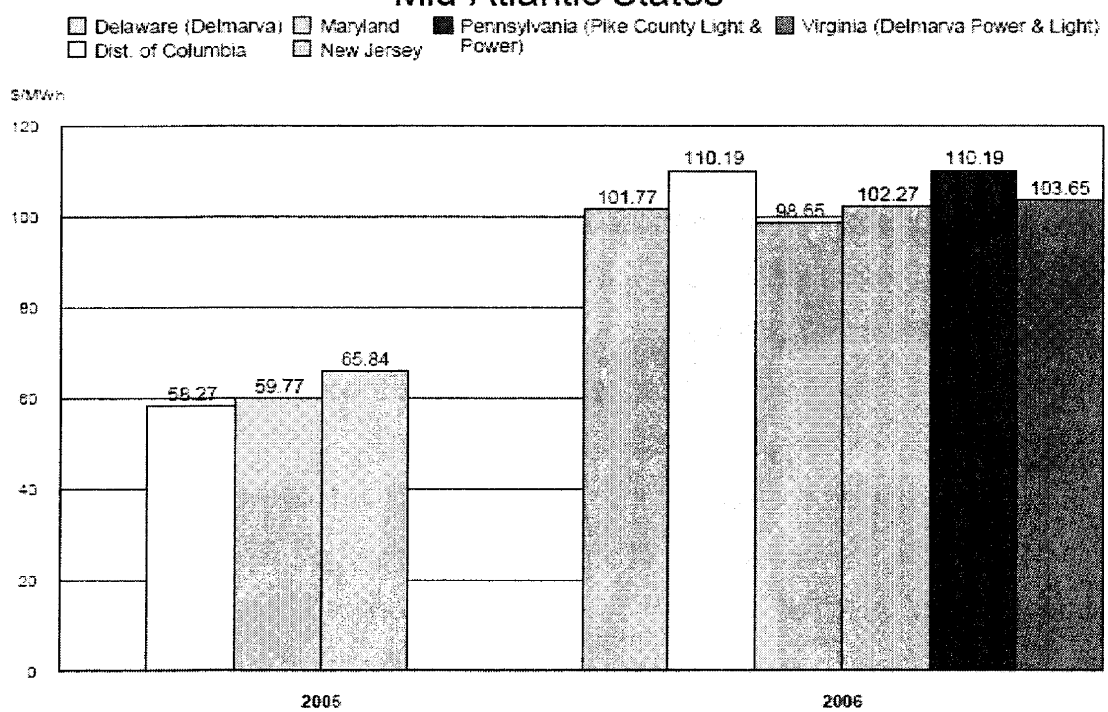
The Delaware Public Service Commission in 2005 determined that power for "Standard Offer Service" will be procured through a competitive bidding process for Delmarva customers. The first bid was conducted in December 2005 ("Tranche 1") and a second and third were held in January 2006 ("Tranche 2 and 3"). The bids were conducted until the load requirements were met for each service type.[8] For residential and small commercial and industrial customers, three procurement lengths, 13 months, 25 months, and 37 months, were bid on by suppliers. The average annual winning bid

[8]The service types were "Residential and Small Commercial & Industrial," "Medium General Service–Secondary (voltage)," "Large General Service–Secondary (voltage)," and "General Service–Primary (voltage)."

prices were all just above ten cents per kilowatthour (kWh). To put this price result into perspective, ten cents per kWh exceeds by about a penny per kWh the *total* average price that residential customers were paying in the state of Delaware during 2005 (see Figure 5) – that is, the nine cents per kWh for the state average includes generation, distribution, transmission, and other utility charges, whereas the ten cent price that resulted from the bidding process is for generation only. These bidding results translated into projected average increases of 59 percent for residential customers and 47 percent to 118 percent increase for business class customers beginning in May 2006 for Delmarva customers.

The bidding and auction price results for Delaware and other mid-Atlantic states are shown in Figure 8. These are weighted average prices for the state (Maryland and New Jersey) or single utility (in Delaware, DC, Pennsylvania, and Virginia).[9] The results in 2005 and 2006 were similar across states for each year, but with a substantial increase in price from 2005 to 2006.

Figure 8. Auction/Bidding Price Results for Generation in Mid-Atlantic States*



*Weighted-average price for state (Maryland and New Jersey) or for utility.
Data Sources: various state sources.

[9]Weighted by sales data from DOE/EIA.

Maryland

Maryland's restructuring law was passed in April 1999 and retail access began for all customers in the four investor-owned utilities on July 1, 2000. Through settlements reached with the state's investor-owned utilities, most residential customers had rate decreases below the rates in effect in June 1999 and had fixed Standard Offer Service prices for the generation supply portion of their bills for customers that did not choose an alternative supplier. Specifically, residential discounts were about 7 percent for Allegheny Power (APS), 6.5 percent for Baltimore Gas & Electric (BG&E), 7.5 percent for DPL/Connectiv (DPL), and 3 percent for Potomac Electric Power Company (PEPCO). The fixed Standard Offer Service supplied by the utilities expires at different times by customer classes and utility company. The residential fixed Standard Offer Service period (which includes the price caps) ends July 1, 2008 for APS and July 1, 2006 for BG&E. The transition ended July 1, 2004, for both DPL and for PEPCO. Also by July 1, 2004, all price caps remaining for non-residential customers had expired.

After the fixed price standard offer service expires, default rates for customers who do not choose an alternative supplier and continue to receive generation supply from their local utility, are based on bids received in a competitive bidding process. Residential customers of PEPCO and DPL/Conectiv began to receive bid-based Standard Offer Service beginning July 1, 2004 (when the fixed price period ended) for customers who did not choose a competitive electric supplier. As a result of the bidding process in 2004, PEPCO residential customers had the power supply portion of their bills increased by 26 percent and the average annual bills increased by approximately 16 percent (an increase of $164.28 for the average residential annual bill). Total bills for PEPCO small commercial customer increased by approximately 13 percent; medium-sized commercial customer bills increased between 25 to 30 percent; large-sized commercial customers' bills increased approximately 48 percent to 57 percent. DPL/Conectiv residential customers had the power supply portion of their bills increased by 19 percent and average annual electric bill increase of approximately 12 percent (an increase of $130.80 for the average residential annual bill).

The bidding process in 2005 resulted in PEPCO's residential customers' generation standard offer increased by 6.6 percent and the overall annual bill increased by 4.6 percent. DPL customers had the generation component of their bill increase by 8.7 percent and the total annual bill increased by 5.8 percent.

Generation supply price freeze for residential customers of Baltimore Gas and Electric Company ends July 1, 2006, and the competitive bidding process has determined the generation price for standard offer customers. (As noted, prices for residential customers of Allegheny Power will remain frozen 2008.) What has become well known at this time, the results of the bidding from this year would have translated into rate increases for residential customers of 72 percent for BGE (an increase of 132 percent in the power supply portion of the bill), 39 percent for PEPCO (an increase of 59 percent in the power supply portion of the bill), and 35 percent for DPL customers (an increase of 52 percent in the power supply portion of the bill). However, the BGE residential rate increases will instead be phased-in, by legislative enactment.[10]

Maryland's bidding results were similar to Delaware's in terms of price (see Figure 8). For residential customers the electricity supply costs were $97.57 per MWh for BGE, 98.85 per MWh for DP&L, and 101.10 per MWh for PEPCO. Also similar to Delaware, all three of these *generation only* prices are well above the 2005 state average *bundled* price for residential customers of 8.23 cents per kWh (or $82.3 per MWh, see Figure 5), which includes generation, transmission, distribution, and other customer charges.

This was the first bidding for BGE residential customers, and the contract lengths were divided with about one-half of the contracts 11 months, one-quarter 23 months, and one-quarter 35 months. Since DP&L and PEPCO residential service was bid in two previous bids, about one-quarter of the contracts were bid two years ago as 35 month contracts. For this year, three quarters of the contracts were put out for bid this year as one and two year contracts. Maryland had three bids that took place from December 2005 through February 2006. Constellation Energy Group, parent company of BGE, disclosed that it won 70 percent of the contracts to supply BGE's customer load beginning in July 2006.[11]

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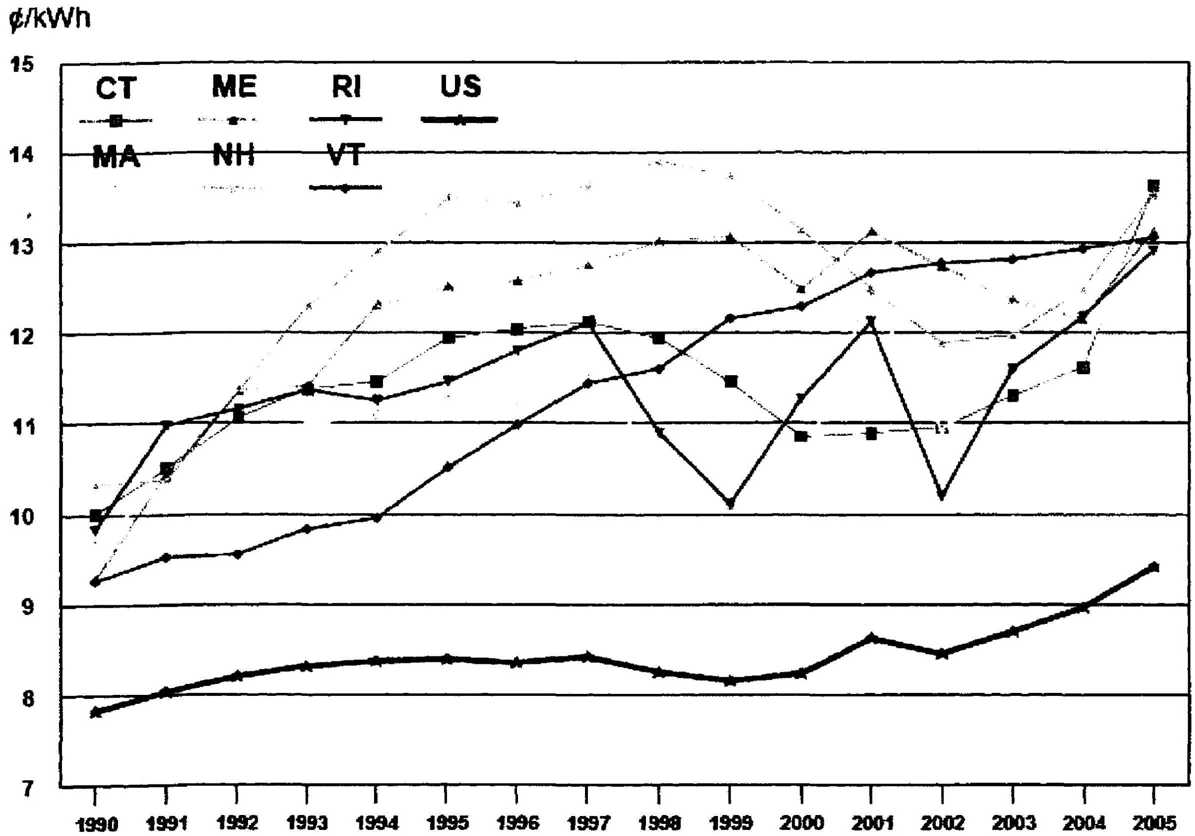
[10]The legislation limited the July 1, 2006 increase to 15 percent for BGE residential customers, allows consumers an option of another deferral beginning June 1, 2007, and adjusts to the full 72 percent increase on January 1, 2008. Customers are required to pay for the deferral with an average monthly charge of $2.19 over 10 years.

[11]*The Baltimore Sun*, "Constellation Defends Profits," June 2, 2006.

New England

All six New England states have had retail electric prices well above the national average for all of the 16 year period shown in Figure 9. Five of the six states have restructured their electric supply industry, Vermont is the only state that has not restructured in New England. In 1990, New England residential prices were 18 percent

Figure 9. New England Residential Average Retail Price

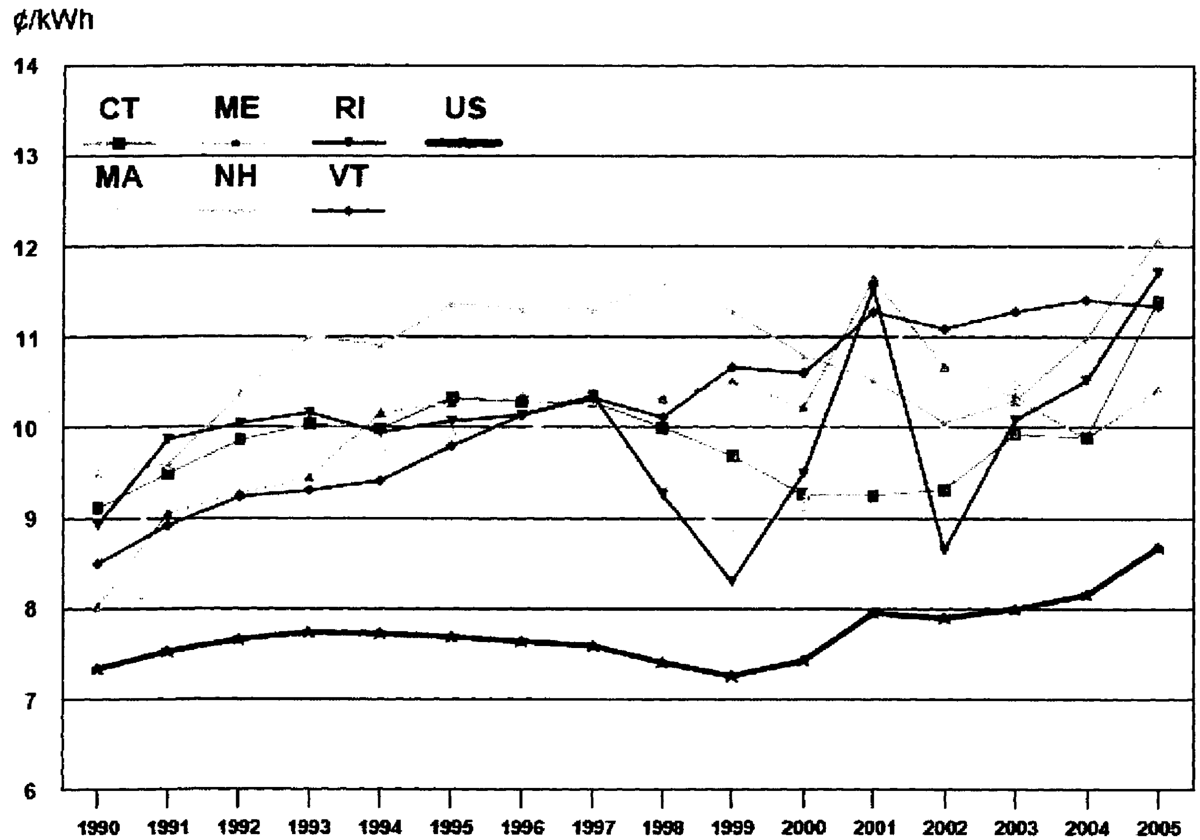


Data Source: DOE/EIA

to 32 percent above the national average. In 2005, that range increased to 37 percent to 45 percent above the national average. All six states had similar prices in 2005, between 12.9 and 13.6 cents/kWh. Except for Maine, which saw a decrease between 2001 and 2004, all other states in the region have seen increasing prices from 2002 through 2005. All six states (including Maine, due to a sharp increase in 2005 above the 2004 price) had higher prices in 2005 than 2002. Four states increased faster that the national average price between 2002 and 2005, Connecticut (24 percent increase), Massachusetts (23 percent), New Hampshire (14 percent), and Rhode Island (27 percent); the national average price increased by 11 percent during that same period.

A similar pattern can be seen for New England commercial customer average prices, shown in Figure 10. Prices have been higher than the national throughout the period shown in the figure. Four states have seen sharply higher prices from 2002 to

Figure 10. New England Commercial Average Retail Price

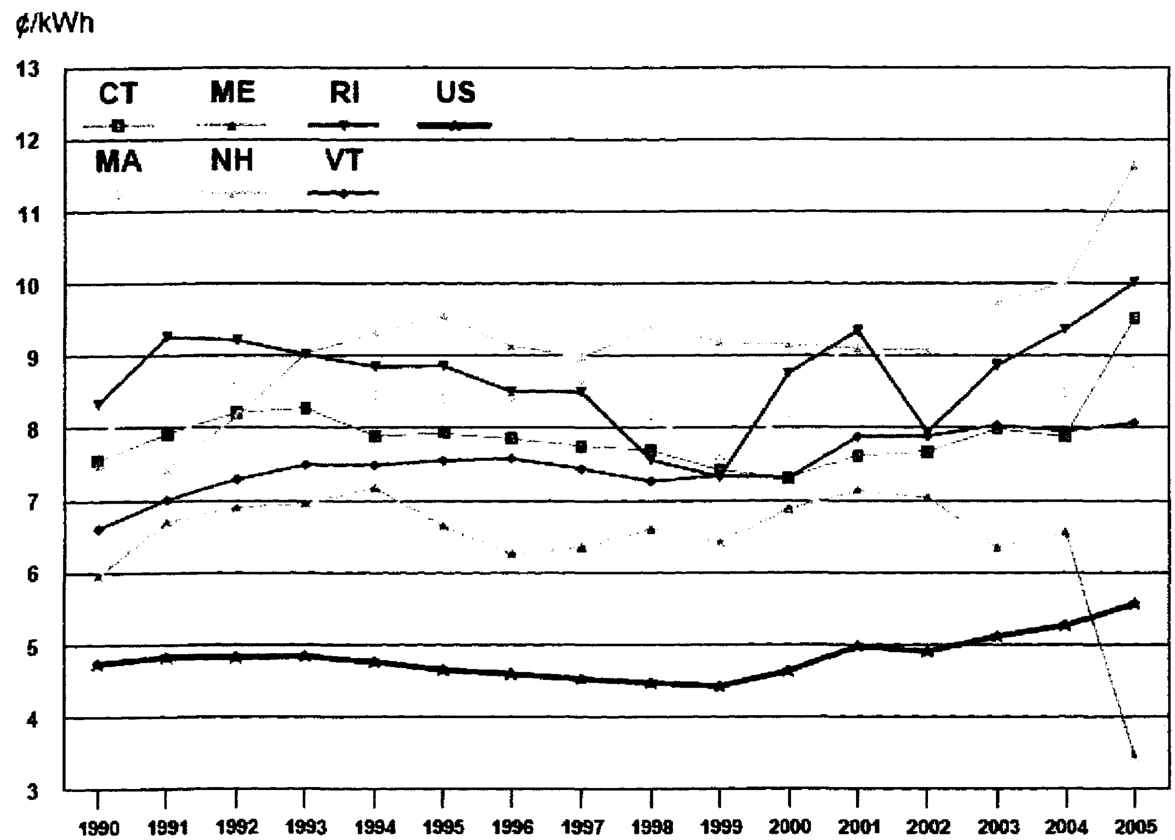


Data Source: DOE/EIA

2005, Connecticut (22 percent increase), Massachusetts (28 percent), New Hampshire (20 percent), and Rhode Island (35 percent). The national average price for commercial customers increased by 10 percent during that same period. Vermont increased by two percent and Maine commercial prices fell by two percent in 2005 from 2002 prices. Similar to residential prices, Maine commercial customer prices fell between 2001 and 2004, then increased in 2005 from the 2004 level. There was a slightly wider range of prices in the region than the residential price, between 10.4 and 12.8 cents/kWh.

Prices for industrial customers in New England have also been consistently above the national average from 1990 through 2005, as shown in Figure 11. The lone exception was the 2005 price for Maine, which had a sharp drop from 2004. However, this is likely due to a small sample size for this customer group in the state or due to a large number of these customers being served by competitive suppliers -- but are not being reported in the data -- or a combination of both factors. Monthly DOE/EIA data shows the number of utility customers in Maine at or about 19 customers for most months in 2004 and 2005. Annual DOE/EIA data report the total number of industrial customers to be 2,832 for 2004. (Also, as with DC discussed above, this reported price is well below wholesale prices in New England – see the New England region in the wholesale section of this report.) This number could be revised in the future, as others have been in the past.

Figure 11. New England Industrial Average Retail Price



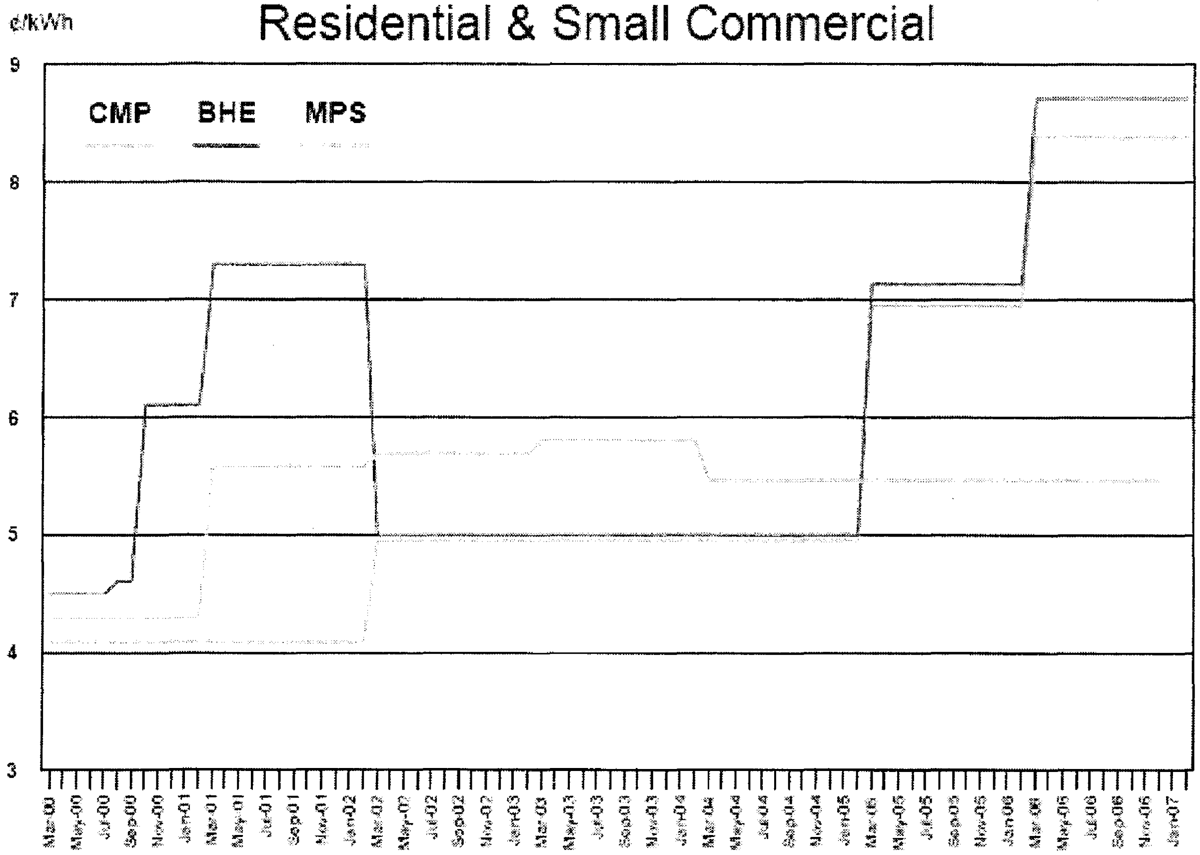
Data Source: DOE/EIA

Except in Maine, prices for industrial customers in New England have also increased between 2002 and 2005. The national average industrial price increased by 13 percent from 2002 to 2005. During that same time period, Connecticut increased by 24 percent, New Hampshire increased by 28 percent, and Rhode Island increased by 26 percent. Massachusetts and Vermont increased by 5 percent and 2 percent, respectively, during the 2002 to 2005 period.

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 standard offer prices that resulted from the bidding for residential and small commercial customers for the three distribution companies in Maine are shown in Figure 12. These prices are for generation only. Standard offer prices for all three companies were steady from early 2002 through early

Figure 12. Maine Standard Offer Service Prices
Residential & Small Commercial

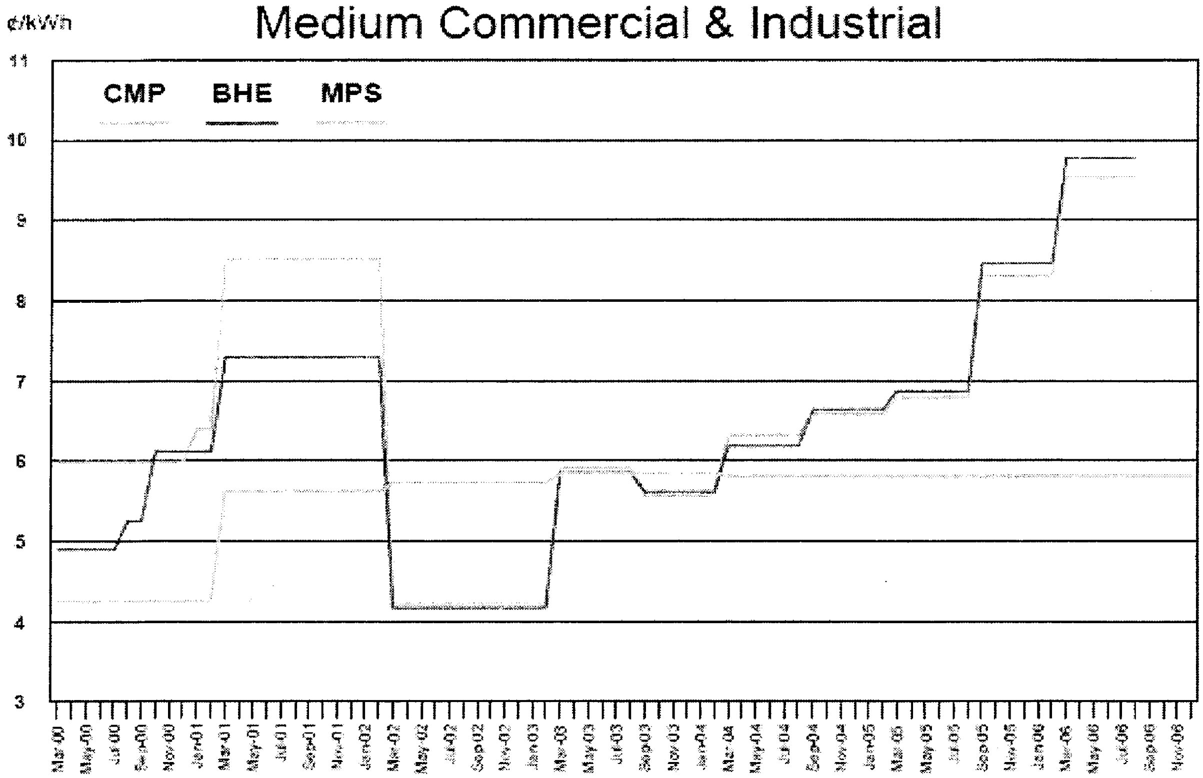


Data Source: Maine Public Utilities Commission.

2005. Prices for Central Maine Power (CMP) and Bangor Hydro-Electric (BHE) increased considerably from about 5 cents/kWh from March 2002 through February 2005, to over 8 cents/kWh beginning in March 2006. This is an increase of 69 percent and 74 percent in the standard offer price for CMP and BHE, respectively. Nearly all the residential customers in CMP and BHE territories are on this standard offer rate for generation service. Maine Public Service (MPS) standard offer service has remained flat, due to long term contract that began in March 2004, and runs through to the end of 2006. As of June 2006, 98 percent of MPS's residential and small commercial customer load was on standard offer service.[12]

Standard offer prices for CMP and BHE medium commercial and industrial customers have also increased steadily since early 2004, as seen in Figure 13. The price has increased by over 70 percent for both CMP and BHE from February 2004 to

Figure 13. Maine Standard Offer Service Prices
Medium Commercial & Industrial



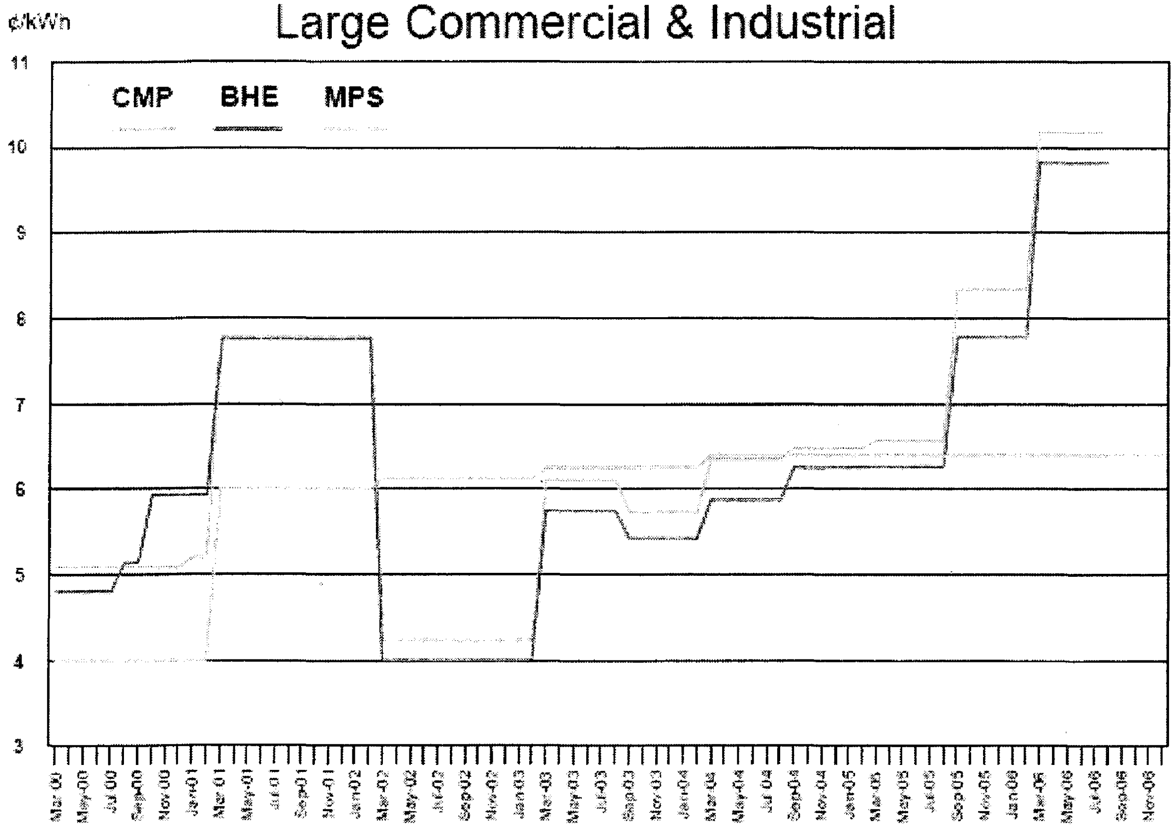
Data Source: Maine Public Utilities Commission.

[12]In July 2003, 36 percent of residential and small commercial load of MPS was served by competitive suppliers, the highest point reached to date for that customer group.

the March 2006 price, which continues through August 2006. For both CMP and BHE, 63 percent of the medium commercial and industrial load were on standard offer service in June 2006. MPS medium commercial and industrial customers are also on a contract that continues through December 2006; 64 percent of these customers' load are on standard offer service as of June 2006.

Standard offer service prices for large commercial and industrial customers reveal a similar pattern, as shown in Figure 14. The standard offer price has increased by over 55 percent for both CMP and BHE from August 2005 to the price that runs through August 2006. MPS standard offer prices are again flat from March 2004 through December 2006. As of June 2006, 13 percent, 43 percent, and 11 percent of the large commercial and industrial customer load for CMP, BHE and MPS, respectively, were on standard offer service.

Figure 14. Maine Standard Offer Service Prices
Large Commercial & Industrial

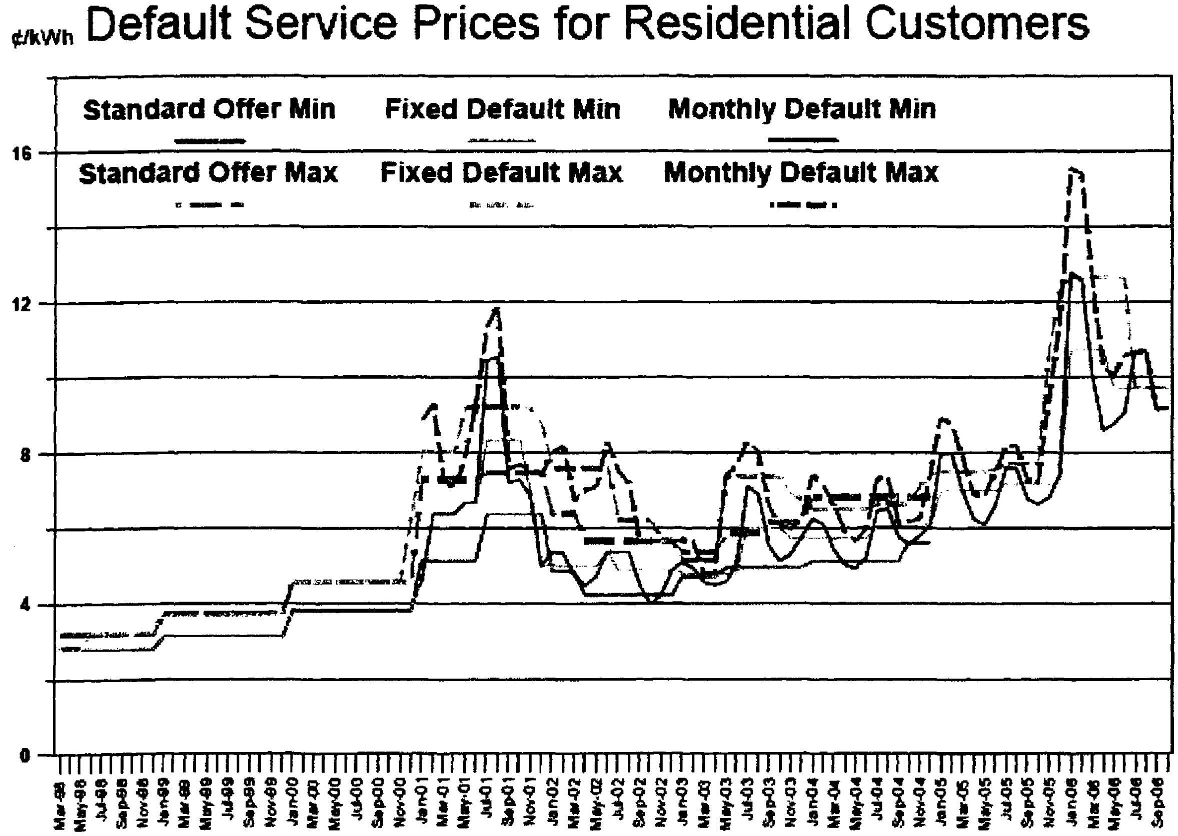


Data Source: Maine Public Utilities Commission.

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 93 percent of the residential customers in the state, see Figure 3). The distribution companies purchase electricity on the market following the procedures of the Massachusetts Department of Telecommunications and Energy. Figure 15 plots the Massachusetts standard offer and default service prices for residential customers back to 1998. These prices are for generation only, not the total bundled prices as shown in the charts of DOE/EIA data, of the maximum and minimum standard offer and default prices for the six distribution companies in Massachusetts. Since the standard offer price ended in early 2005, default prices have increased significantly. The monthly default price spiked to over 15 cents/kWh in January and February of 2006 and remain above 10 cents/kWh through August of 2006. All prices will be above 9 cents through October 2006.

Figure 15. Massachusetts Standard Offer and Default Service Prices for Residential Customers

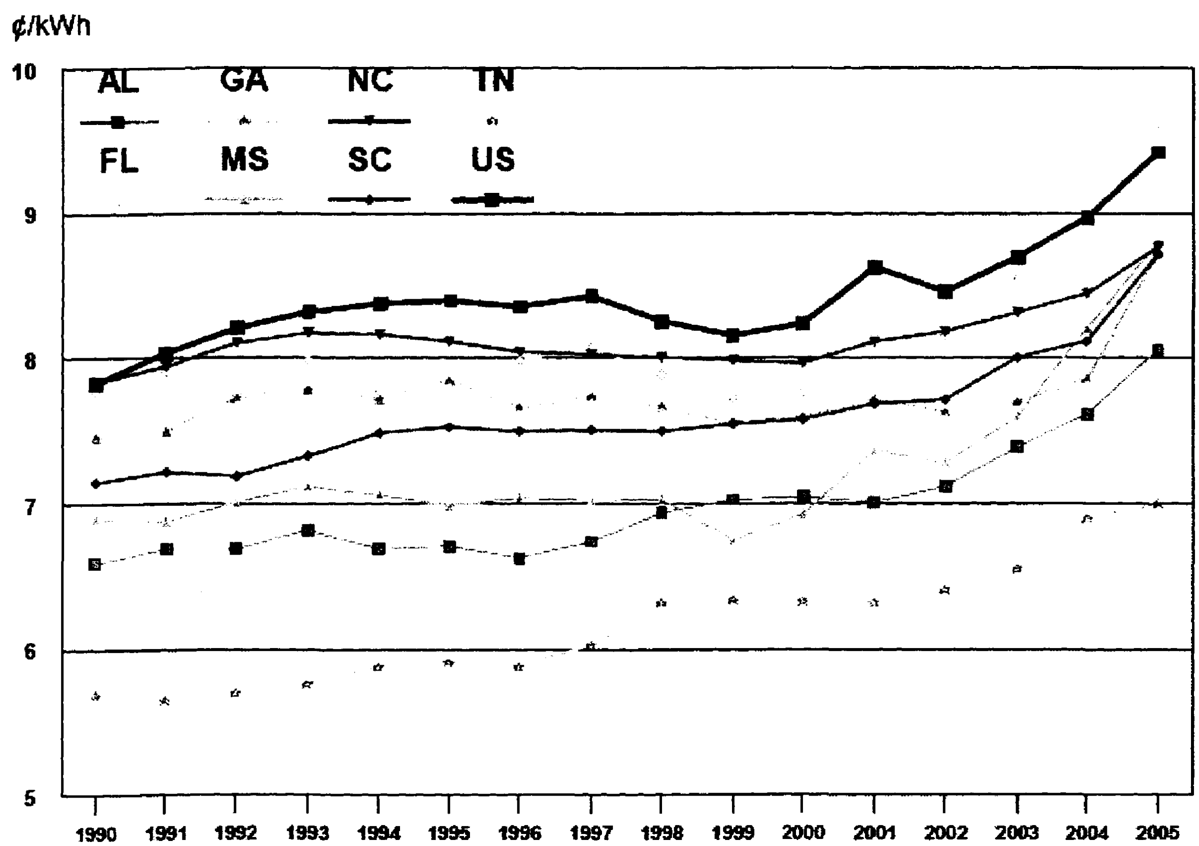


Data Source: Massachusetts Department of Telecommunications and Energy.

Southeast

Southeastern state residential average retail prices are shown in Figure 16. No state in the Southeast region has restructured retail electric supply. Prices in the region were relatively flat for the period beginning in 1990, but have seen significant increases since 2002. Five of the seven states in the region had prices increase faster than the national average of 11 percent between 2002 through 2005. However, every state in the region is below the national average, except Florida, which was only two-tenths on a cent above in 2005 and two-hundredths of a cents above in 2004. Florida has seen an 18 percent increase in residential prices between 2002 and 2005. In several respects, however, Florida is a special case that separates it from most other states in the country. First, similar to other regions of the country, higher natural gas prices and an increasing portion of the generation using natural gas has contributed to price increases. Florida increased from 16 percent of the generation in the state using natural gas in 1994, to 32

Figure 16. Southeast Residential Average Retail Price



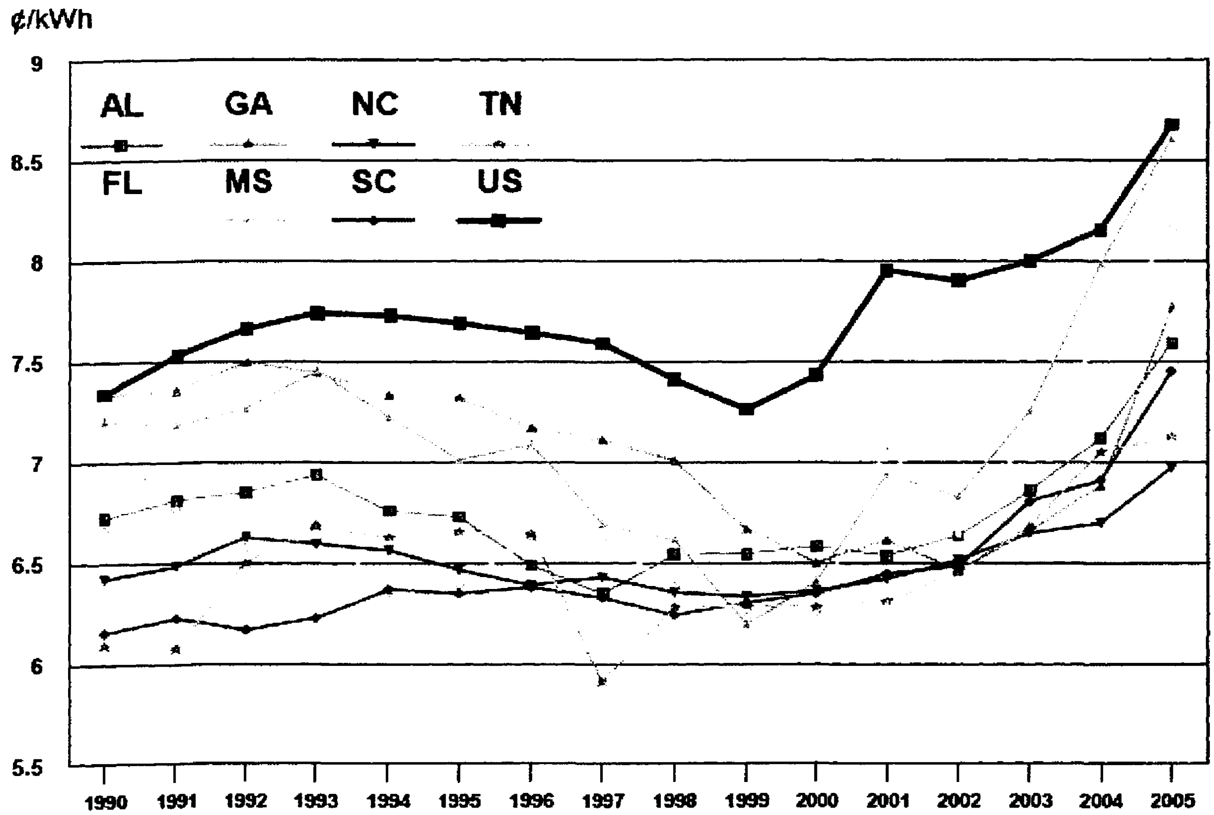
Data Source: DOE/EIA

percent in 2003.[13] Second, generation capacity increased by 27 percent between 1994 and 2003 to meet load for a fast growing area of the country. Finally, the state has faced costs related to fixing damage from several recent hurricanes and the "hardening" of their distribution system for future storms.

The fastest price increase in the region was Mississippi, which increased by 21 percent between 2002 and 2005. The state has seen a 131 percent increase in generation capacity between 1994 to 2003 – 94 percent of that increase was natural gas capacity, increasing the percentage share from 9 percent of the state's capacity was natural gas to 57 percent. Most of this new capacity was added by independent power producers.

For commercial customers in the southeast region, shown in Figure 17, prices have generally followed the national trend for commercial customers. Prices fell or were

Figure 17. Southeast Commercial Average Retail Price



Data Source: DOE/EIA

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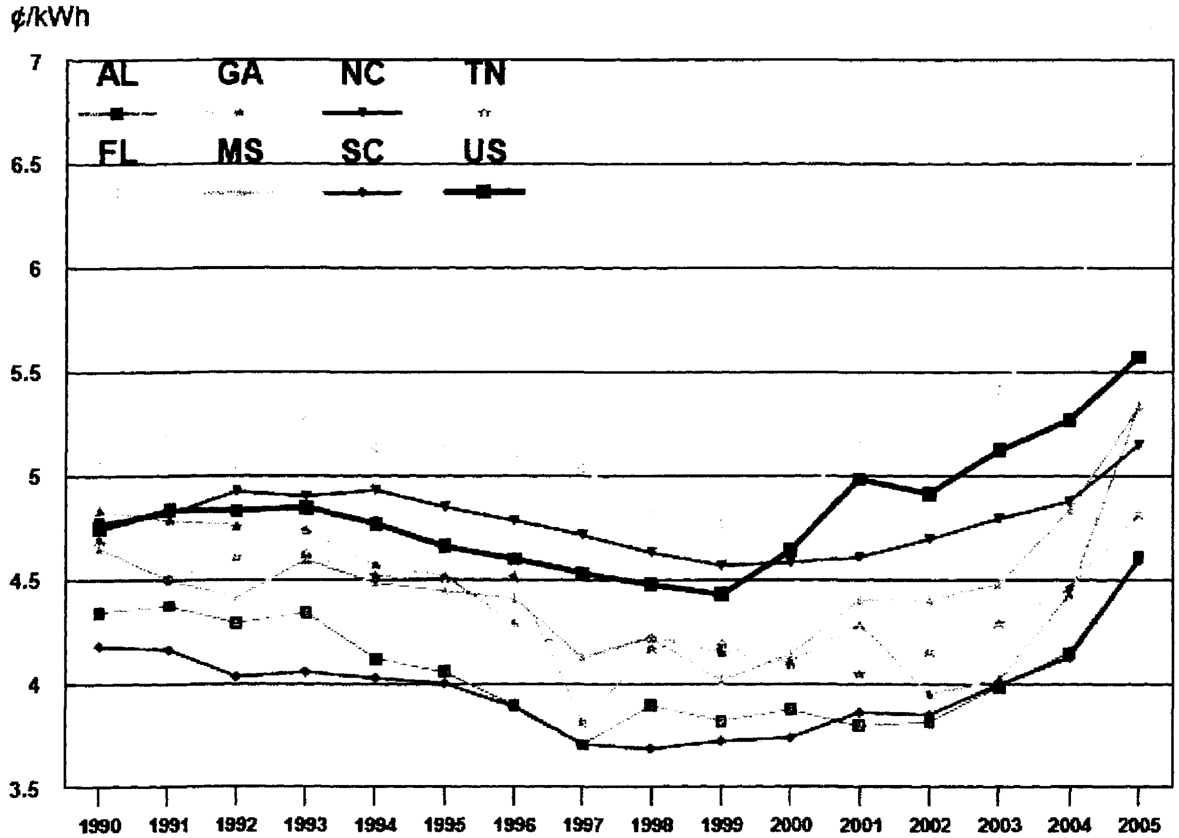
[13]State capacity and generation figures are based on data in U.S. Department of Energy, Energy Information Administration, "State Electricity Profiles 2003," April 2006.

relatively unchanged through the late 1990s. Then, similar to the pattern seen for residential customers, prices increased considerably since 2002. All the states in the region remained below the national average for this customer category. The price pattern over time is again nearly the same for industrial customers in the southeast region, as can be seen in Figure 18. However, Florida has consistently been above the national average throughout the period shown in the figure, but never by more than one cent/kWh (for 2005, the difference was just under one cent/kWh – before that, the difference was usually one-half of a cent/kWh or less). All other state industrial customer prices were below the national average from 2000 through 2005.

Figure 18. Southeast Industrial Average Retail Price

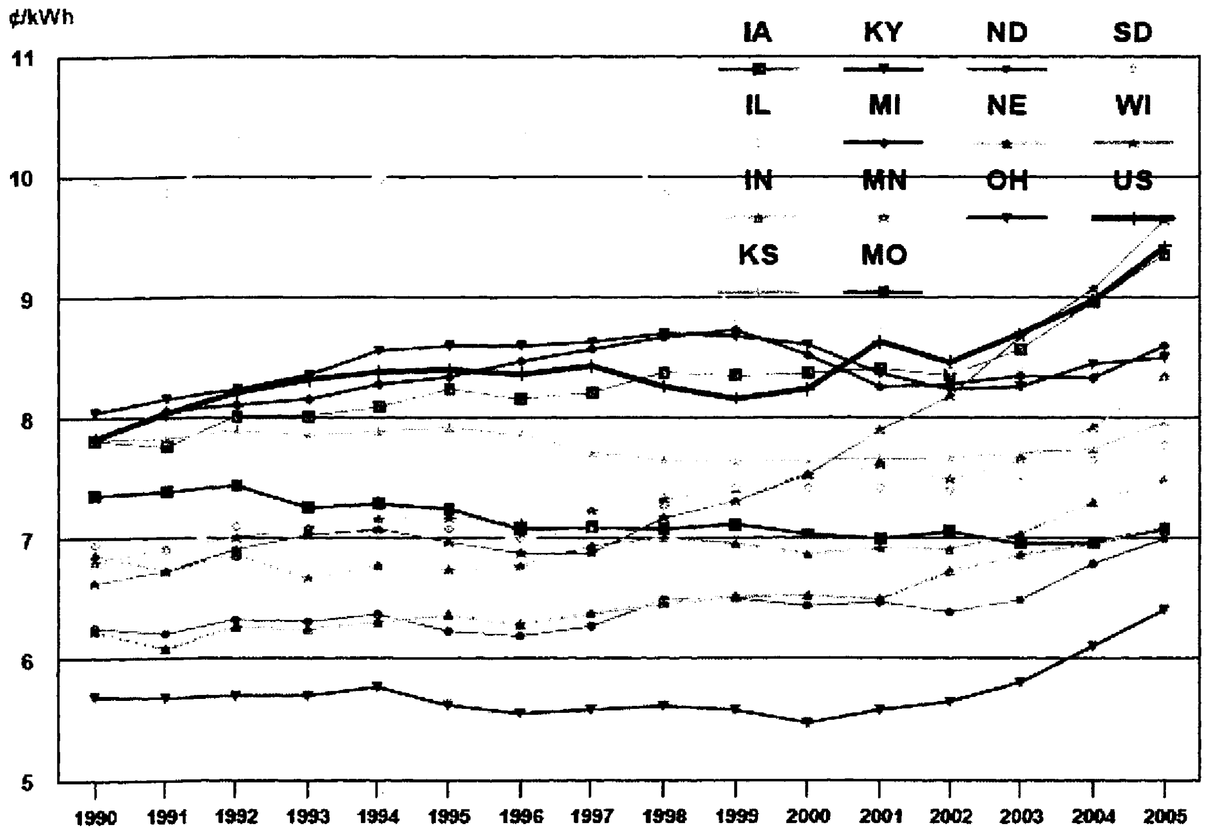


Data Source: DOE/EIA

Midwest

Most states in the Midwest region have not restructured -- the exceptions are Illinois, Michigan, and Ohio. Illinois and Ohio are still in a transition period and customers are not fully seeing market prices at this point. Michigan ended the transition rate caps at the end of 2005, but maintains regulatory control of the generation price with retail access, which is unusual for restructured states (Arizona is perhaps the only other example of this).[14] Midwest regional prices have been the most stable overall of any region in the country. For residential customers in the Midwest region, shown in Figure 19, there are two notable exceptions. Illinois had prices well above other states in the region until, beginning in 1998, a 15 percent and then later an additional 5 percent

Figure 19. Midwest Residential Average Retail Price



Data Source: DOE/EIA

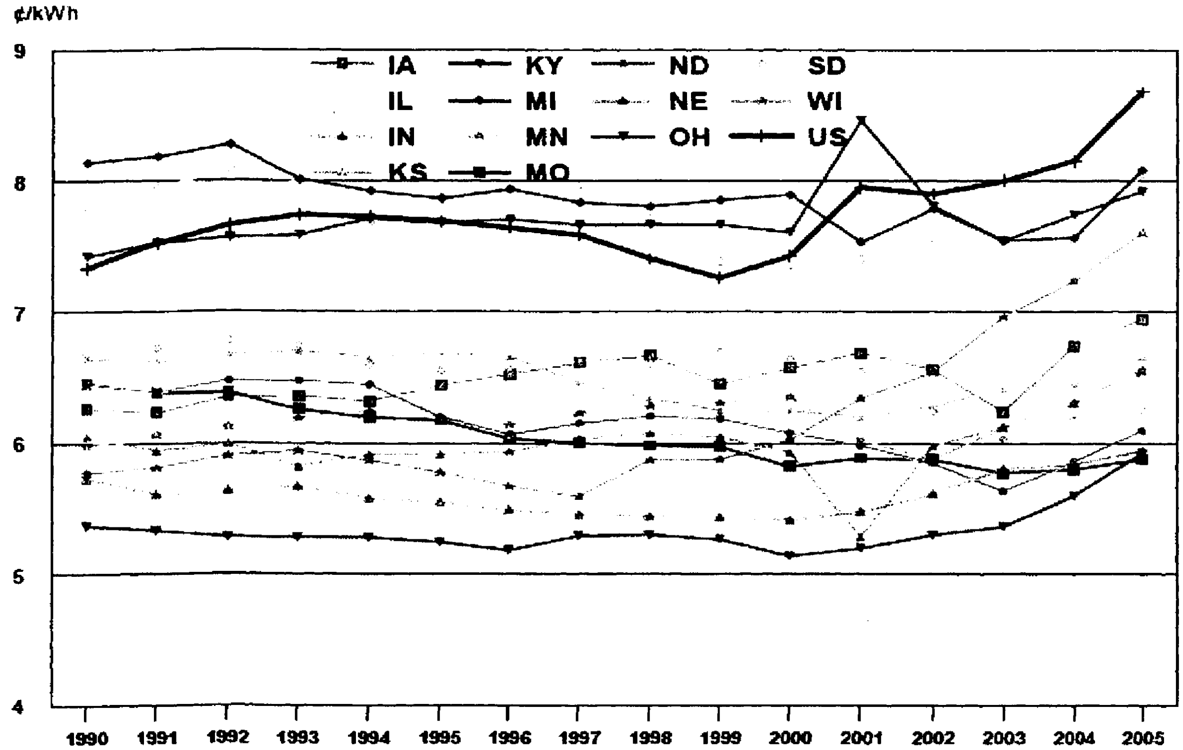
[14]This will be explored in more detail later in this report. Most restructured states have either moved to a market-based means to determine retail price (through a procurement process, wholesale market, or customers purchasing directly from suppliers) or are in a transition period where the price is capped or controlled – but will become market determined after the transition period is over.

discount for Commonwealth Edison and Illinois Power (now AmerenIP) residential customers were applied. As mandated by Illinois' restructuring law, rates will remain frozen until December 31, 2006. Illinois is currently planning to use an auction approach, similar to the New Jersey BGS auction, to procure power supply for customers beginning in 2007.

The other notable exception to the region's relative stability is Wisconsin. The state started well below the national average, but beginning in about 1998, Wisconsin residential customer prices began to rise to slightly above the national average for the last two years in the figure, about 2 tenths of a cents/kWh above in 2005. Wisconsin Electric Power, now We Energies, which serves the Milwaukee area up through eastern Wisconsin into the Upper Peninsula of Michigan, has been adding new generating capacity in its area. They expect to expand total generation from about 6,000 MW currently to approximately 8,300 MW when completed (DOE/EIA data shows the capacity in the state expanded by about 2400 MW between 1994 and 2003, about a 21 percent increase). They are also upgrading existing plants and the distribution system.

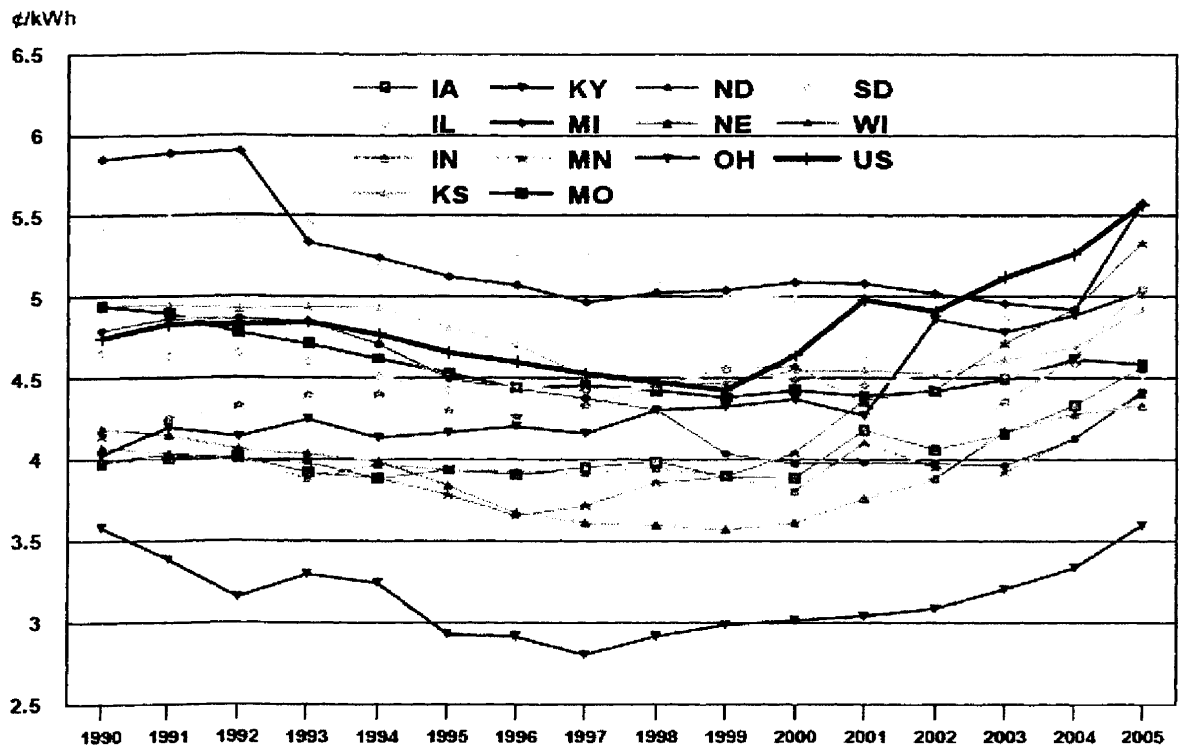
Commercial customer prices in the Midwest, Figure 20, are also relatively stable throughout the period shown in the figure, again, with the notable exception of Wisconsin. All states in the region, including Wisconsin, have been below the national average since 2002. Industrial customer average prices in the region, shown in Figure 21, are again showing a similar pattern, where all states are below the national average (the Michigan average industrial price was nearly identical to the national average in 2005).

Figure 20. Midwest Commercial Average Retail Price



Data Source: DOE/EIA

Figure 21. Midwest Industrial Average Retail Price

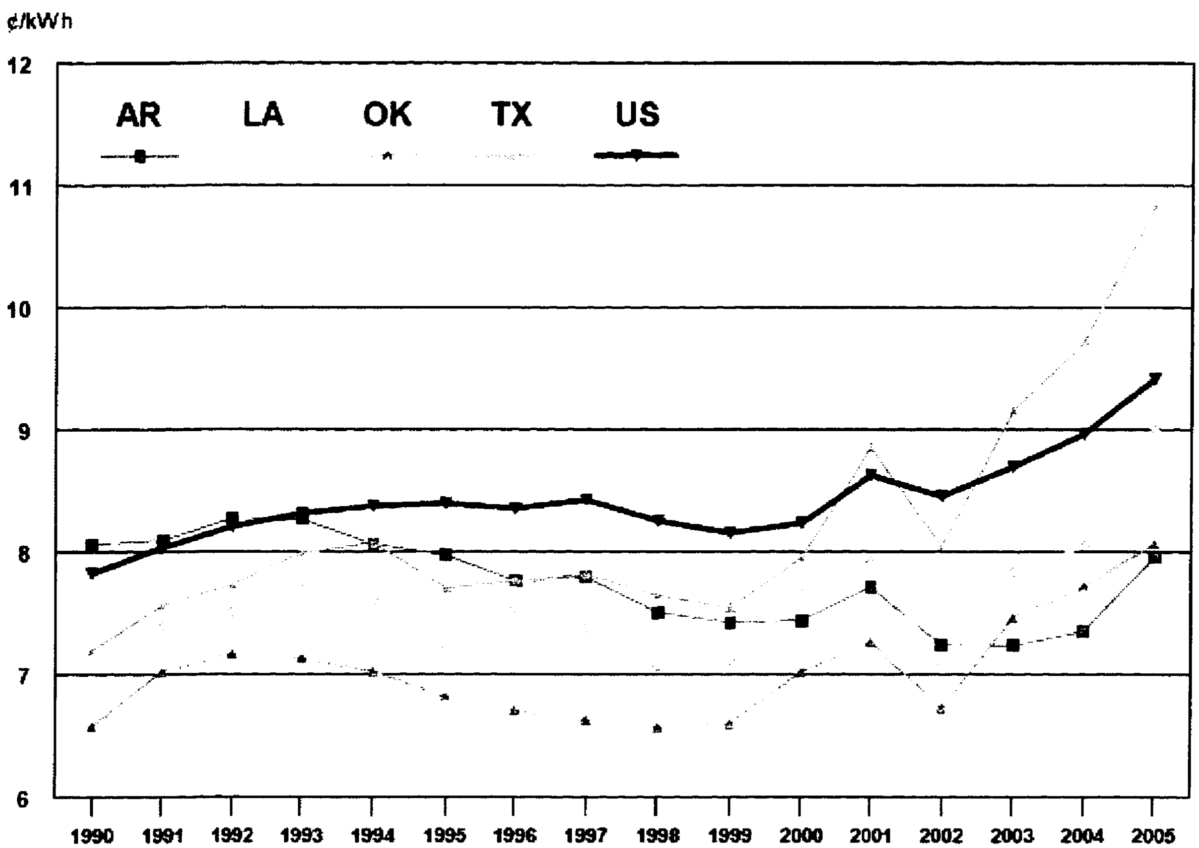


Data Source: DOE/EIA

Mid-South

Texas (in the ERCOT region of the state) is the only state in the four state region that has restructured. Texas residential retail prices were consistently below the national average throughout the 1990s, as Figure 22 shows. However, Texas residential prices have risen considerably from 2002 through 2005, at more than three times the national average percentage increase, almost 35 percent increase versus the national average 11 percent increase during that time span. Prices in Louisiana and Oklahoma have also risen faster that the national average, at 27 percent and 20 percent respectively, but are still below the national average. The region has one of the highest proportion of its generation using natural gas in the country. Texas has 42 percent of its generating capacity and nearly half or the power generated from natural gas in 2003 (49 percent of the total MWh produced in the state), Louisiana is close at 41 percent of its capacity and

Figure 22. Mid-South Residential Average Retail Price

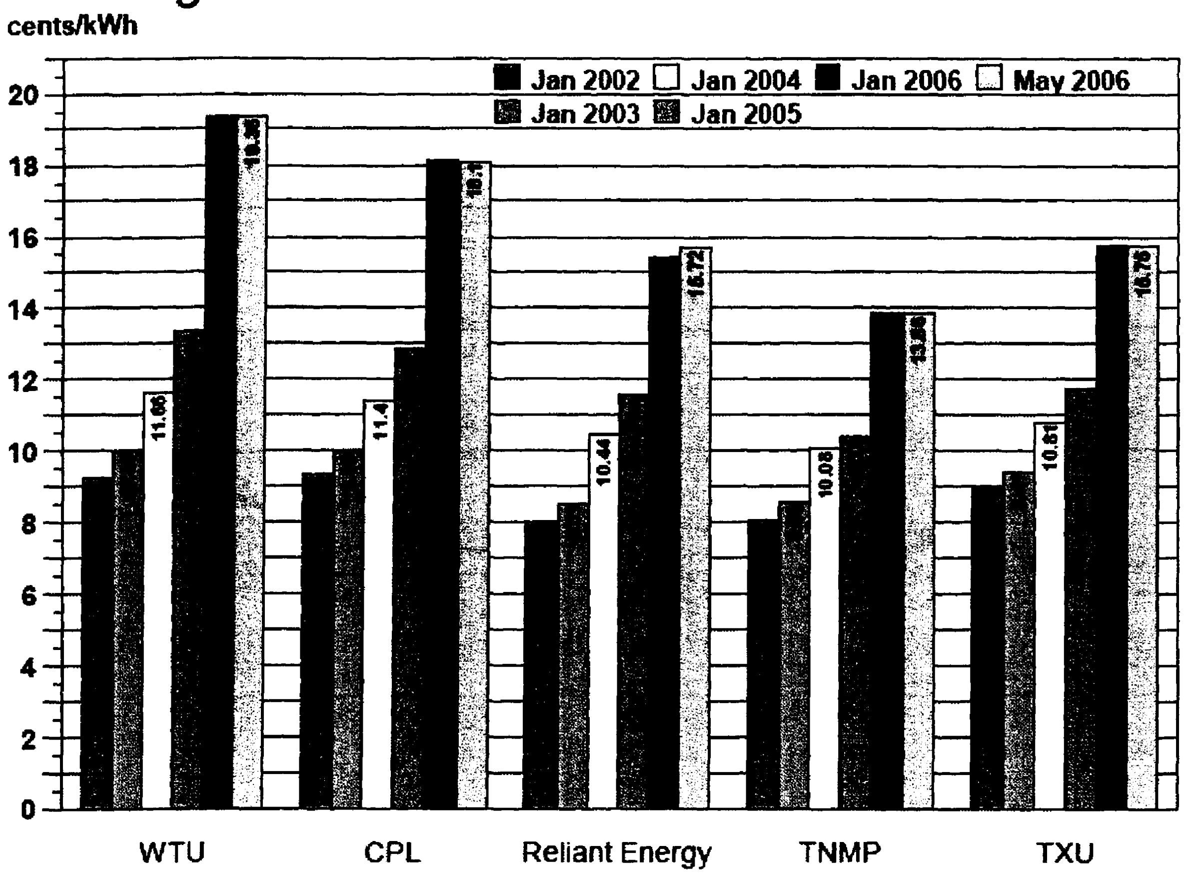


Data Source: DOE/EIA

48 percent of the generation from natural gas, and Oklahoma had 52 percent of its capacity and 36 percent of its generation using natural gas in 2003.[15]

For a closer examination of retail prices in Texas, Figure 23 graphs the "price-to-beat" rates for residential customers from January 2002 to May 2006 in the five Texas service territories with retail access in the state. The price-to-beat is the price used by customers to compare the distribution company price with the price offered by 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 May 2006, the price-to-beat rates have

Figure 23. Texas Residential "Price-to-Beat"



Data Source: Public Utility Commission of Texas

[15]DOE/EIA, "State Electricity Profiles 2003," April 2006.

increased by almost 72 percent in Texas-New Mexico Power (TNMP), almost 75 percent in TXU Electric & Gas (TXU), 94 percent in Central Power and Light (CPL), over 96 percent in Reliant Energy (Reliant), and over 110 percent in West Texas Utilities (WTU). About 62 percent of residential customers are paying the price-to-beat rate (Figure 3).

Texas has one of the most active retail markets in terms of residential customers being offered competitive prices. From a survey of offers by the Texas Public Utility Commission,[16] there were six suppliers and seven offers below the price-to-beat in WTU's service area, nine suppliers and 11 offers below the price-to-beat in CPL's service area, 10 suppliers and 10 offers below the price-to-beat in Reliant's service area, four suppliers and five offers below the price-to-beat in TNMP's service area, and eight suppliers and nine offers below the price-to-beat in TXU's service area. However, while these offers are below the current price-to-beat for the respective service area, the best offers are at substantially higher prices than existed when retail access began January 2002. For WTU's service area, the best current offer is 71 percent higher than the January 2002 price-to-beat for customers in the area. The best offer in CPL's area is 56 percent higher than its 2002 price-to-beat, the best offer in Reliant's area is 73 percent higher, the best offer in TNMP's area is 63 percent higher, and the best offer in TXU's area is 54 percent higher.

The pattern is again similar for mid-south commercial customer prices, as shown in Figure 24. The Texas state average price for commercial customers was below the national average from 1990 through 2004, and was just above in 2005. Louisiana also saw a substantial increase since 2002, but remained just below the national average in 2005. Texas commercial customer prices increased by 27 percent from 2002 to 2005, while Louisiana increased 30 percent during that same time period (the national average price increase for commercial customers was just under 10 percent). For industrial customers in the region, as seen in Figure 25, both Texas and Louisiana have been above the national average price for industrial customers from 2003 through 2005. Both states again have had substantial price increases for industrial customers since 2002, 53

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[16]Public Utility Commission of Texas, "Retail Electric Service Rate Comparisons," May 2006.

percent Texas in and 55 percent for Louisiana (the national average price for industrial customers increased by 13 percent).

Figure 24. Mid-South Commercial Average Retail Price

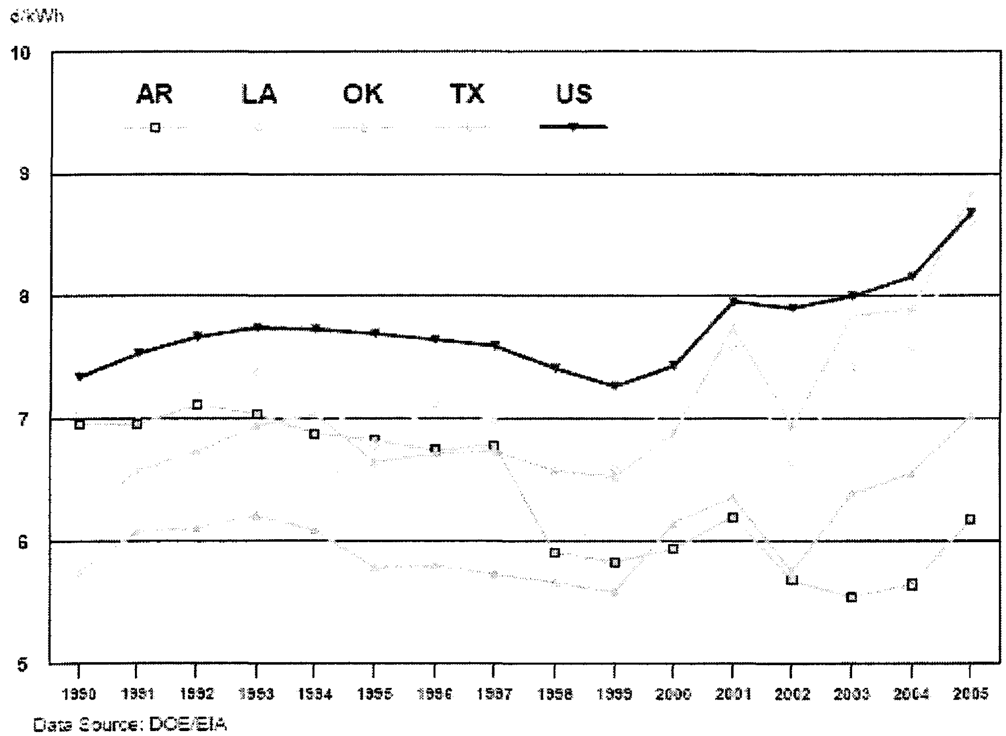
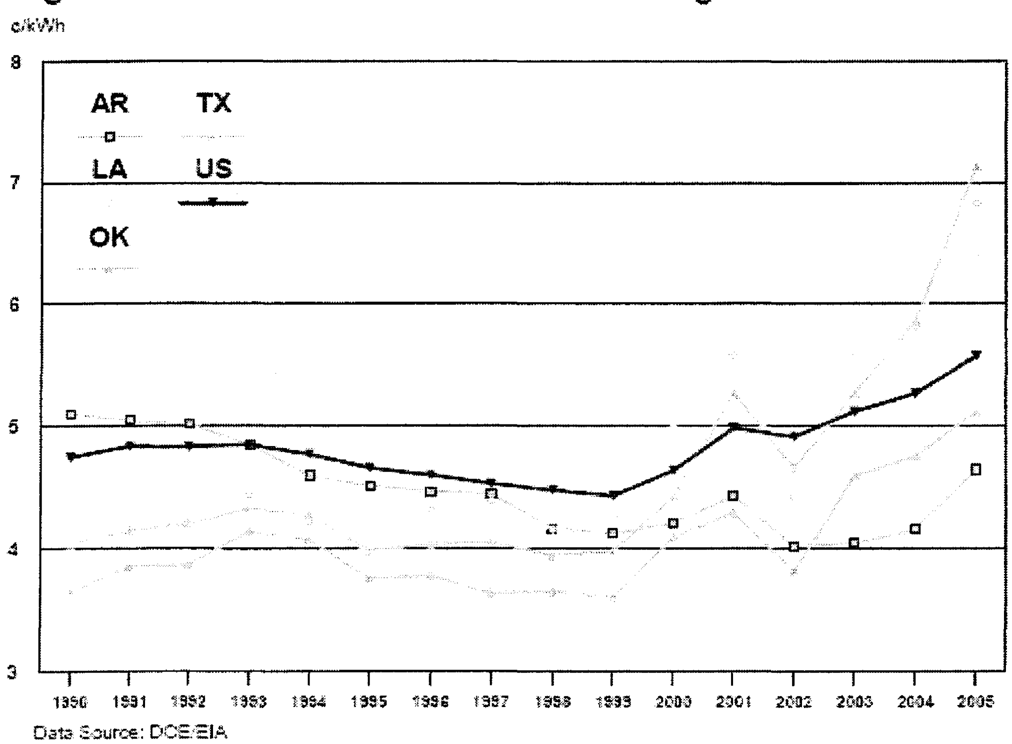


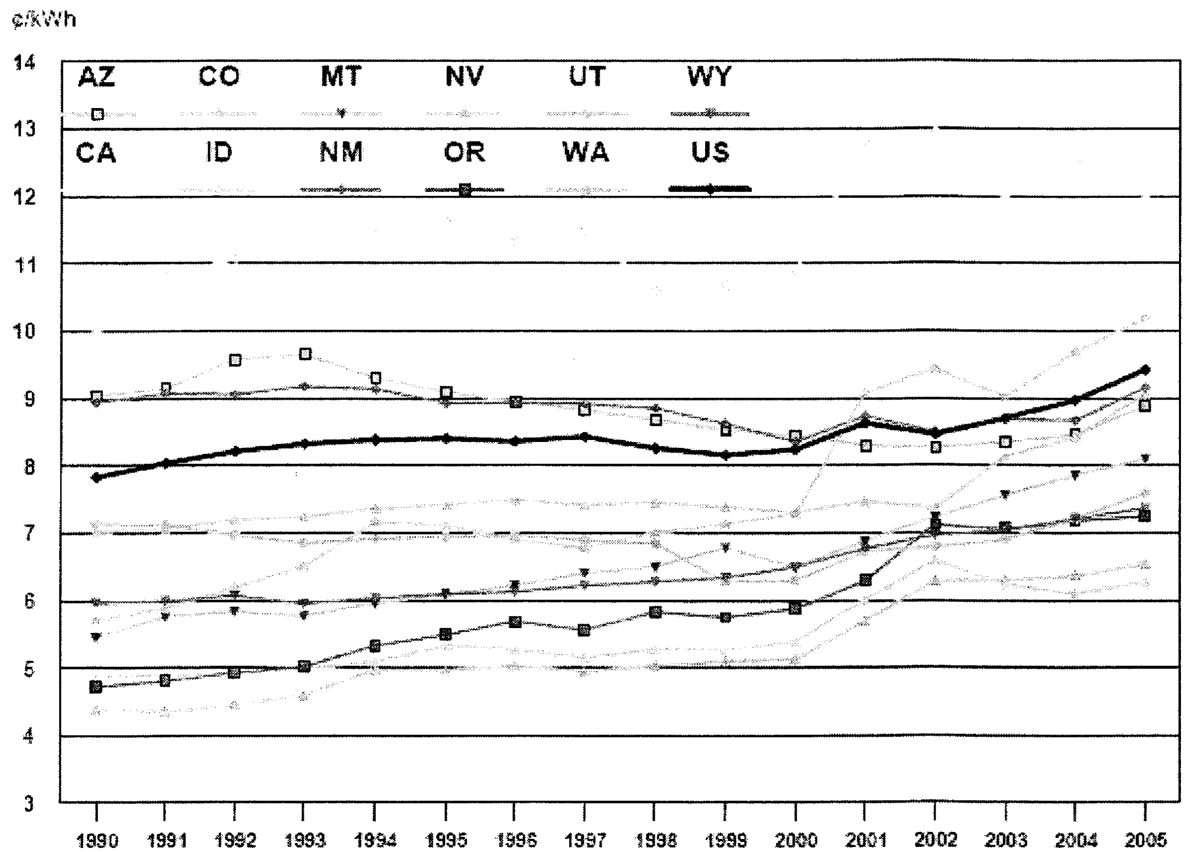
Figure 25. Mid-South Industrial Average Retail Price



West

Similar to the Midwest, western residential average state prices were relatively stable from 1990 through 2000, as can be seen in Figure 26. The impact of the western power crisis can be seen from 2001 and in later years across the western states. California, of course, had retail access at the time of the western power crisis, and suspended it September of 2001. Arizona is the only state in the west that continues to have retail access for all customer groups, which began January 1, 2001 (as Figures 2, 3, and 4 show, no retail customers are currently be served by alternative suppliers in the state). Montana began retail access for large customers in 1998 (the same year California began), but has continued to postpone retail access for residential customers. Nevada and Oregon are open for large customers only.

Figure 26. West Residential Average Retail Price

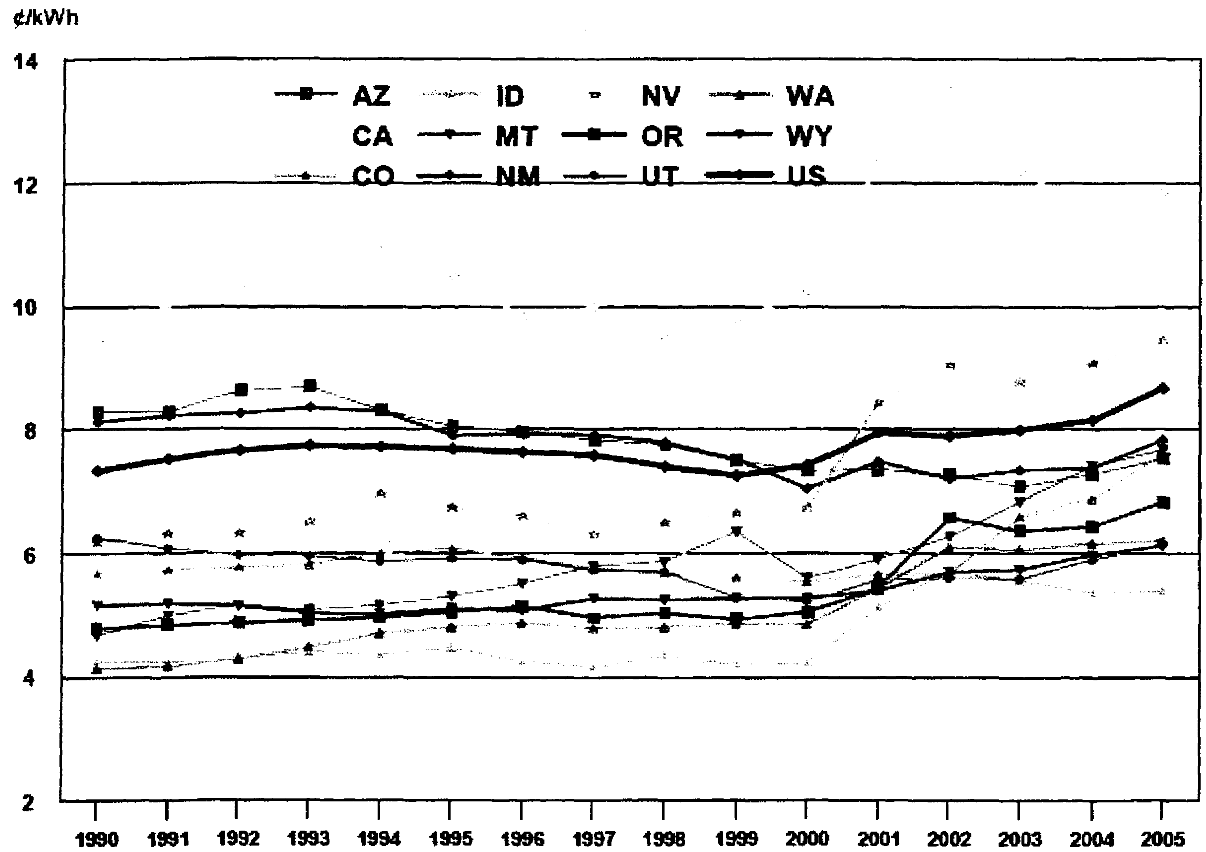


Data Source: DOE/EIA

California has been consistently above the national average throughout the period in Figure 26. The California discount can be seen in 1998 and then the significant price increases in 2001 and 2002 in the aftermath of the power crisis. Prices have leveled off since, but California residential prices remain 27 percent above the national average in 2005. Nevada residential prices have also increased to above the national average, to eight percent above the national average in 2005. All other western states were below the national average in 2005.

A similar pattern can be seen for western commercial customers in Figure 27. California is again consistently above the national average throughout the period and, following the western power crisis, most states in the region saw price increases. California commercial customer prices also declined from the peak in 2002, but remain well above the national average, by almost 37 percent. Nevada also moved above the national average following the crisis, to nine percent above the national average in 2005. All other states remained below the national average, however, Colorado and Montana had significant price increases of 34 percent and 22 percent, respectively, between 2002

Figure 27. West Commercial Average Retail Price

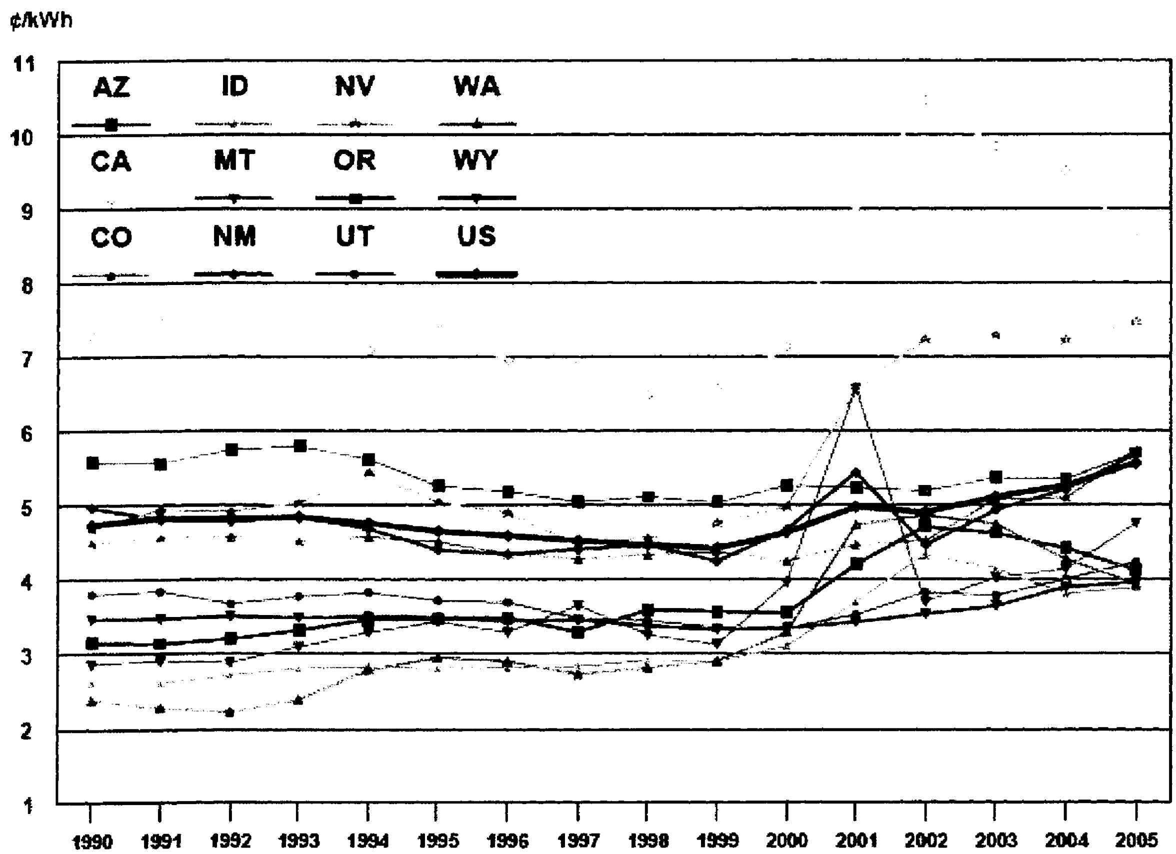


Data Source: DOE/EIA

and 2005 (the national average increase for this customer group was 10 percent for that time period).

Figure 28 shows the industrial customer average prices for the western states. California again was consistently above the national average throughout the period, and saw a 59 percent increase in the industrial customer prices from 1999 to 2002. Then, the price declined, but remained 54 percent above the national average price. Nevada also saw an increase in price for this customer group, with the 2005 average state price at 34 percent above the national average. Montana had a considerable spike in the industrial customer price in 2001, the peak of the western power crisis – the price in 2001 was more than twice the 1999 price. The Montana price dropped back down, but increased by 29 percent between 2002 and 2005. Oregon and Washington had *decreases* in the industrial customer prices of 13 percent and 19 percent, respectively, between 2002 and 2005.

Figure 28. West Industrial Average Retail Price



Data Source: DOE/EIA

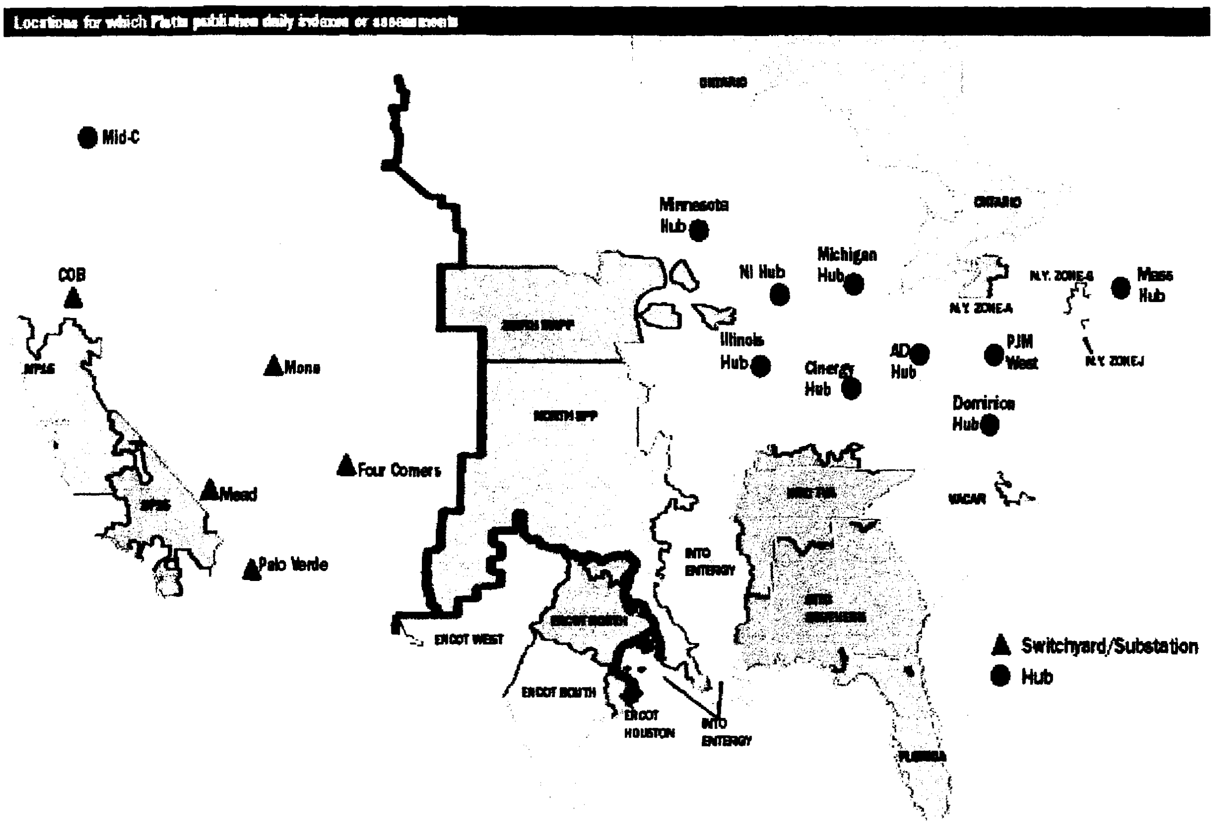
Regional Wholesale Markets

This section reviews eight wholesale electricity regions in the U.S. The country is divided based on markets and/or regional proximity. Some new nodes have been created in some regions or have changed since last year's Performance Review. The regions and hubs examined below are:

1. PJM: PJM, PJM West, AD Hub, Dominion Hub, and NI Hub
2. ISO New England: Mass Hub
3. New York ISO: NY Zone A, NY Zone G, and NY Zone J,
4. MAPP South and Midwest ISO: Michigan Hub, Minnesota Hub, Illinois Hub, and Cinergy Hub
5. VACAR, Southern, and Florida
6. TVA, Entergy, SPP North
7. Texas
8. West: Mid-Columbia Hub, CA-OR Border, NP15, SP15, Mead, Palo Verde, Four Corners, and Mona Utah.

These regions, hubs, or substations are shown in Figure 29.

Figure 29. Map of selected U.S. electricity hubs

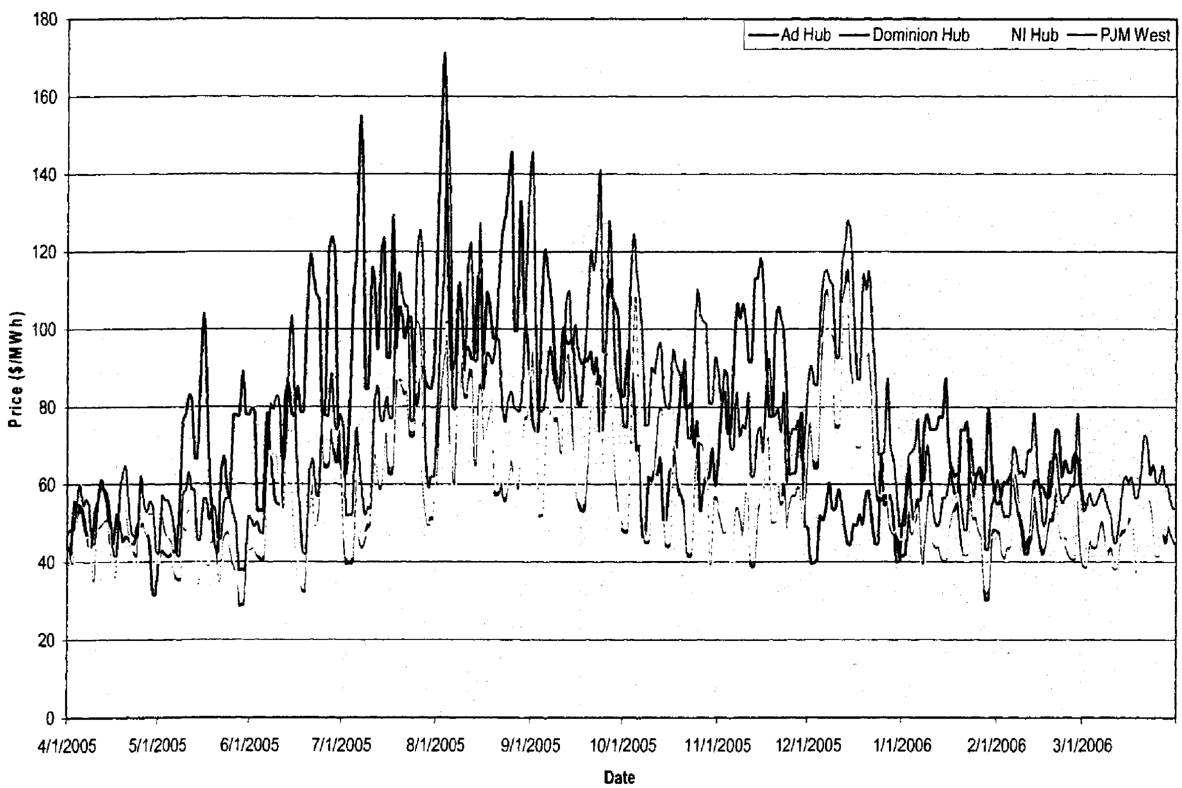


Source: Platts at http://www.platts.com/Oil/Resources/Glossaries/

PJM

Figure 30 shows the daily average peak hour prices for hubs within PJM. The Dominion Hub (in the Commonwealth of Virginia) entered PJM on May 1, 2005. Prices of the hubs varied greatly over the time period examined. They ranged from a high of $170/MWh (August 3, 2005 at the Dominion Hub) to a low of $25.25/MWh (May 30, 2005 at the NI Hub), with most prices being within a $40 to $80 range. Noticeable peaks can be seen at the time of Hurricanes Katrina and Rita. The price fluctuations seemed to subside slightly thereafter, but not until the beginning of 2006. The NI Hub and the AD Hub tended to have the lowest prices and were highly correlated with one another. When Dominion entered PJM, the prices at that hub seemed to be negatively correlated with the other hubs. Prices at the Dominion Hub were generally higher than other hubs within PJM from May 1, 2005 until September 1, 2005. Clear examples of this can

Figure 30. Daily Average Peak Hour Prices for Hubs within PJM

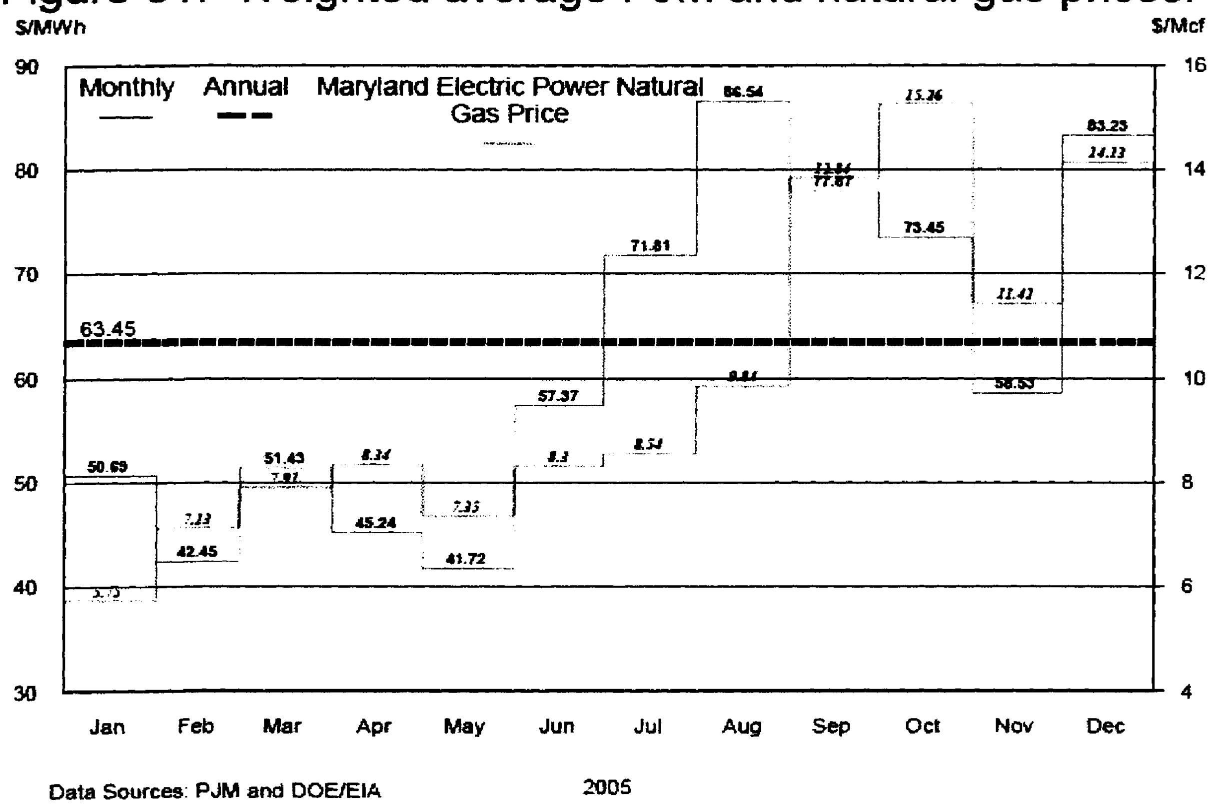


Data Source: Platt's *Megawatt Daily.*

be seen through the end of June 2005. At that time, the prices at the Dominion Hub began to follow the other nodes at least in direction, and eventually with respect to price levels. Price spikes occurred at the Dominion Hub in the May, June, and July. Price spikes occurred in the other three hubs in December, while the Dominion hub remained lower.

Figure 31 compares the weighted-average PJM day-ahead market price with monthly average natural gas prices in 2005.[17] Natural gas prices rose sharply in September and October, in the wake of the hurricanes, however, power prices were increasing throughout the summer months and reached the annual peak in August. PJM power prices actually fell September through November and climbed again in December. This suggests that warm weather in the PJM region had an impact on power prices before natural gas prices began their record climb.

Figure 31. Weighted average PJM and natural gas prices.

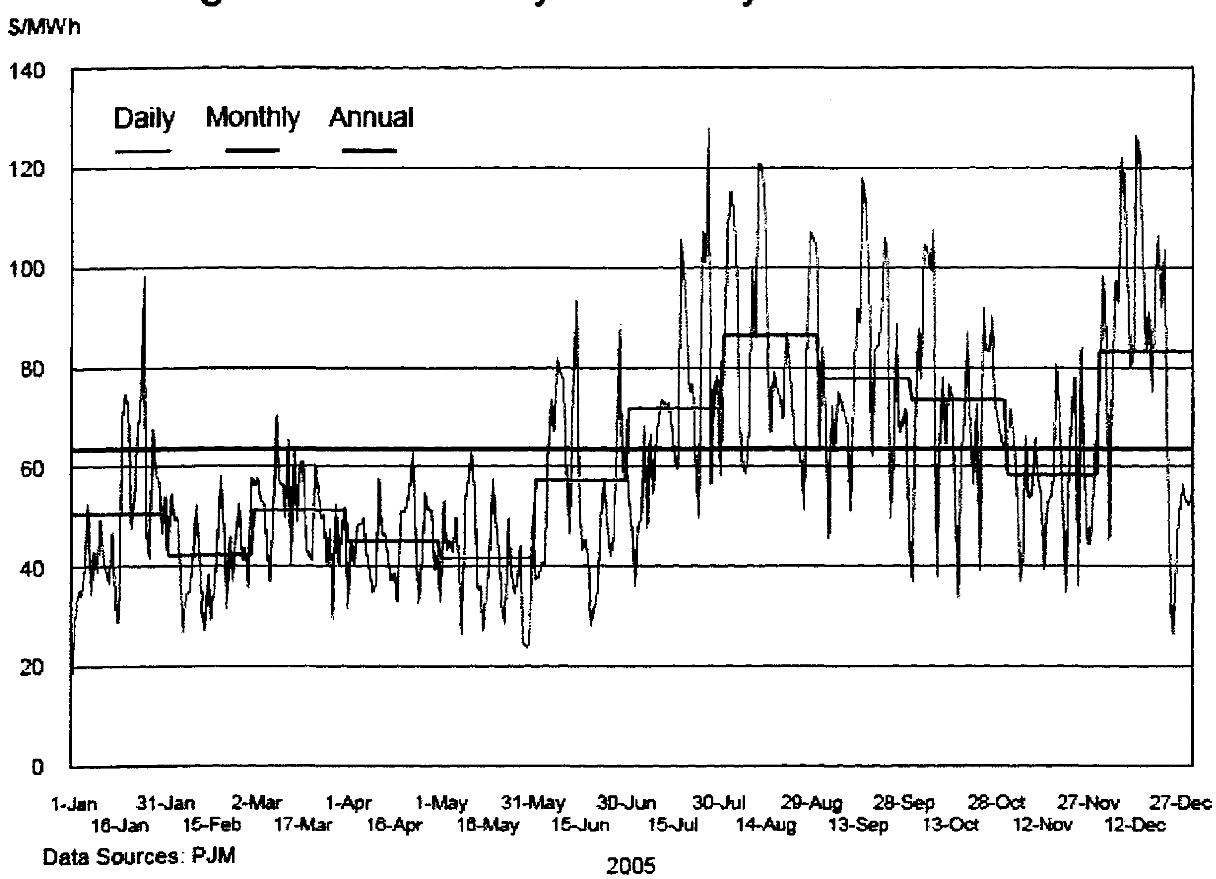


Data Sources: PJM and DOE/EIA

[17] All references to natural gas prices refer to the EIA-DOE "Electric Power Price." These prices can be found at http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

Figure 32 shows the PJM weighted-average again with the weighted-average daily price in the PJM day-ahead market. As can be seen in the figure, the market became more volatile in about June and continued throughout the rest of the year. Figure 30 shows that price volatility abated in early 2006.

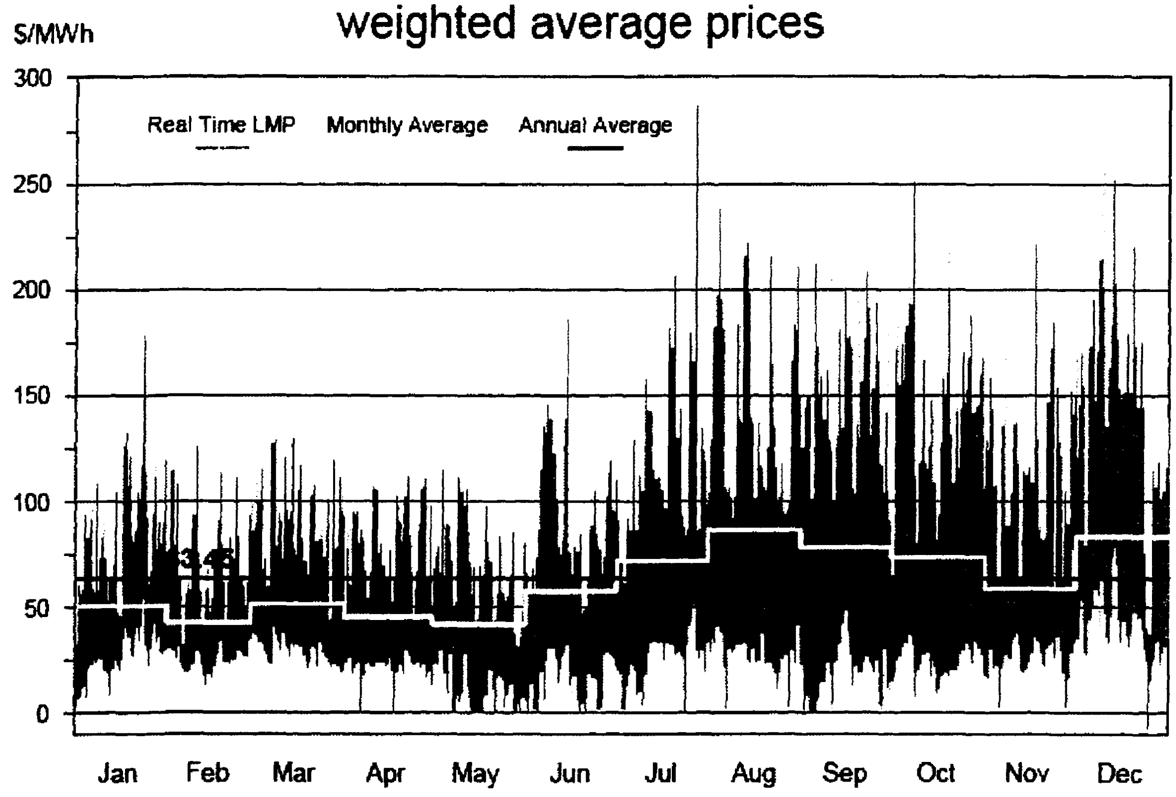
Figure 32. Monthly and Daily PJM Prices.



Data Sources: PJM

The price volatility in the second half of the year can be seen more vividly in Figure 33 that shows real-time hourly prices, along with the weighted-average monthly prices and the annual weighted-average price. Hourly prices well above $100/MWh were common, again before natural gas prices reached their record levels.

Figure 33. PJM real-time hourly, monthly and annual weighted average prices

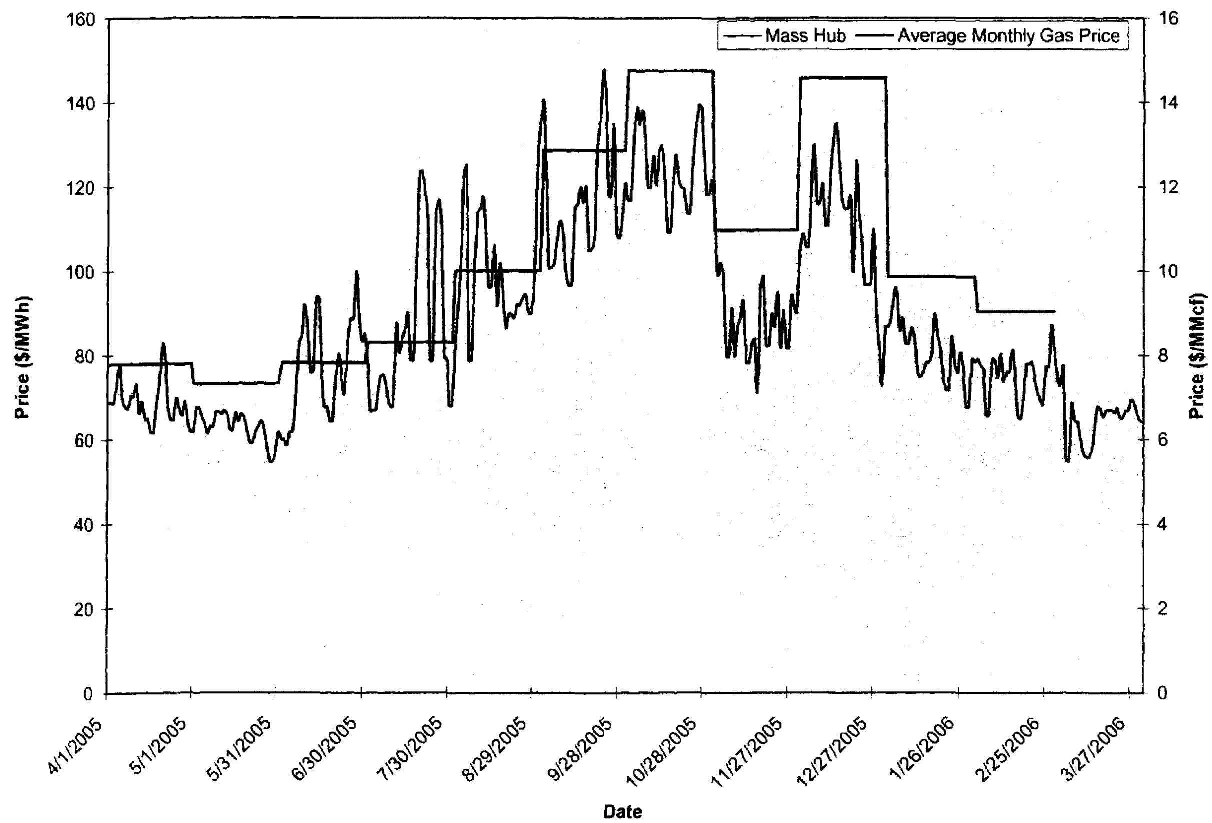


Data Source: PJM

ISO New England: Mass Hub

Figure 34 shows the daily average peak hour prices for the Mass Hub in ISO New England and the monthly average natural gas prices. Wholesale electricity prices ranged from a high of $148/MWh (September 22, 2005) to a low of $55/MWh (May 27, 2005 and March 5, 2006). With rare exceptions, prices remained above $100/MWh from the end of August to the start of November. As with PJM prices, New England power prices increased and became more volatile during the summer of 2005, before the natural gas price increases. However, the power prices are more closely correlated with natural gas prices. This is likely a result of the higher proportion of New England natural gas generation. The impact of the hurricanes on natural gas and power prices can be seen in the fall months of 2005. The increase in electricity prices in late January can be attributed to increased demand for natural gas for heating in addition to electricity generation which led to higher natural gas prices.

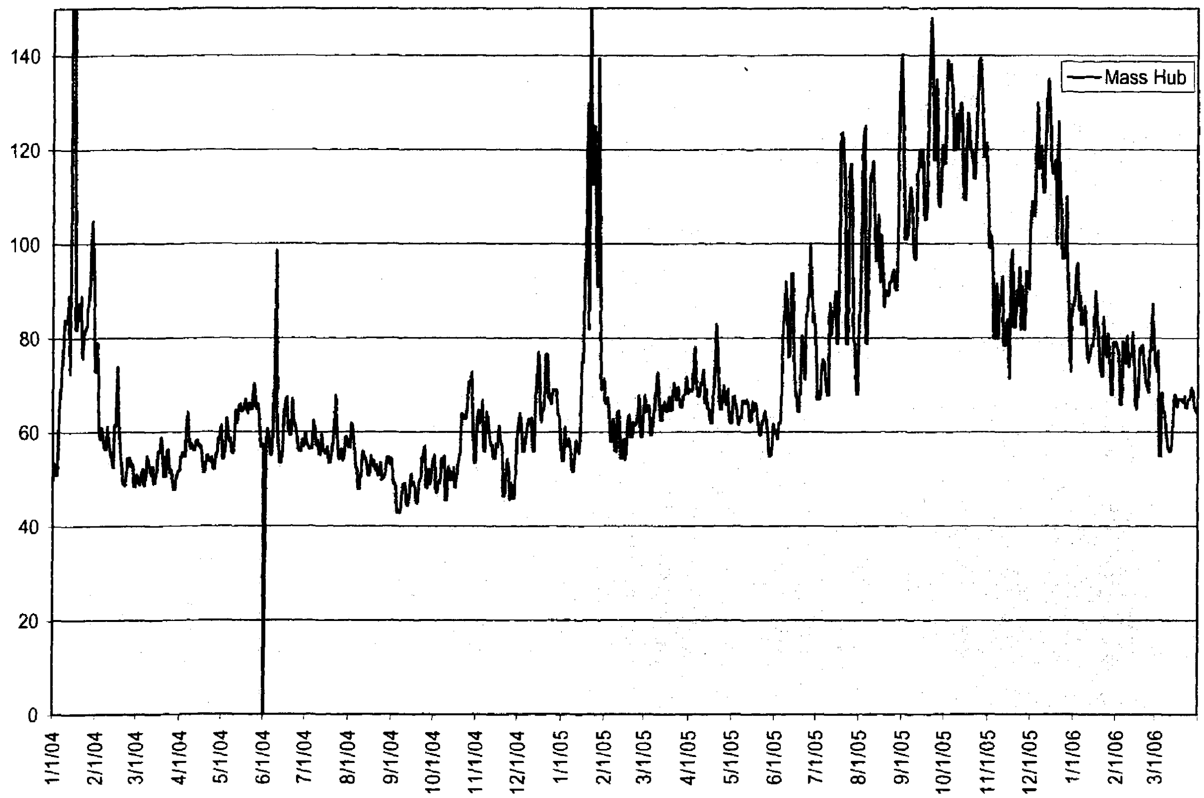
Figure 34. Daily Average Peak Hour Prices for Mass Hub and Monthly Average Natural Gas Prices



Data Source: Platt's *Megawatt Daily* For MA Hub, EIA-DOE for natural gas prices.

Figure 35 extends that time frame to examine the price path back to the start of 2004. The graph shows greater variability in the wholesale electricity price in 2005 as compared to 2004. It also shows prices to be reasonably stable in the summer months, but showing greater volatility during the winter months. This volatility has increased over time. The Mass Hub saw higher prices in the winter of 2005-2006 than for the winter of 2004-2005. These higher prices were also sustained for a longer period of time.

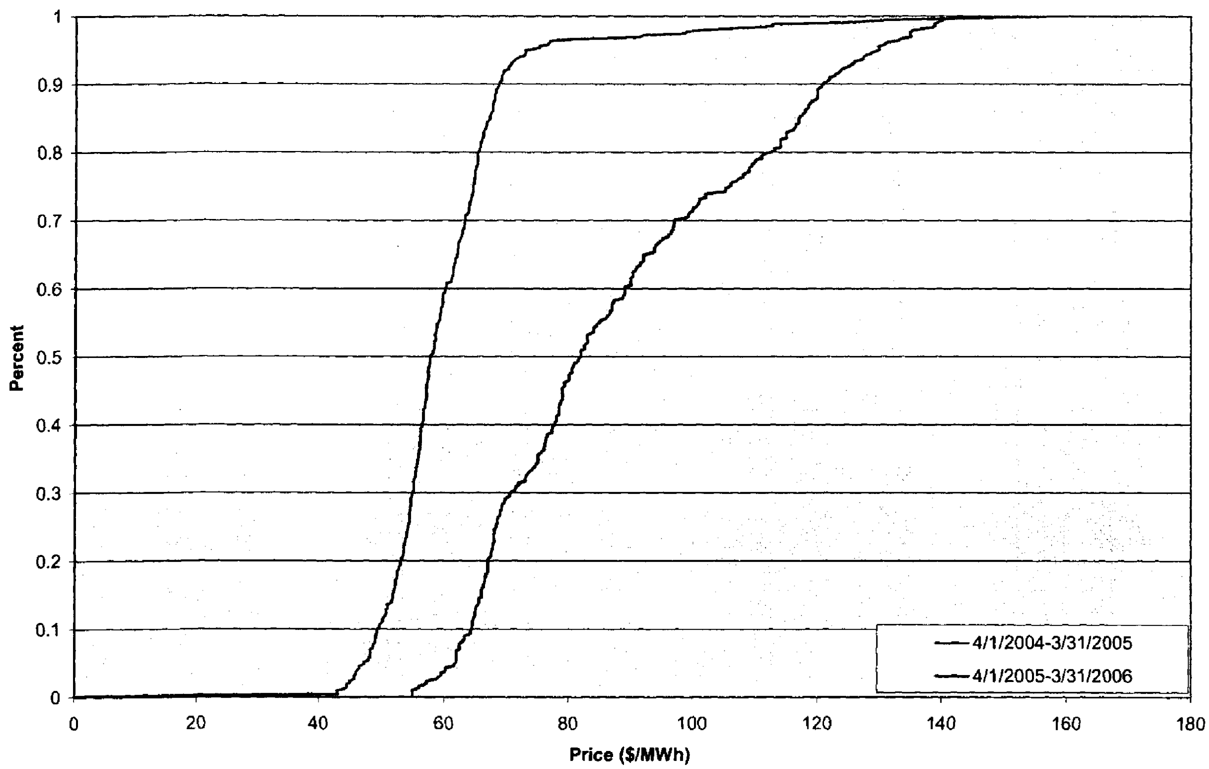
Figure 35. Daily Average Peak Hour Prices for Mass Hub from 1/1/2004 through 3/31/2006



Data Source: Platt's *Megawatt Daily.*

Figure 36 compares the price duration curve from April 2004 through March 2005 with April 2005 through March 2006. The price duration curve shows what percent of time the price was at a given level. For example, 50 percent of the time the price at the Mass Hub was at or below $82/MWh between April 2005 through March 2006. This graph shows that the median price at the Mass Hub increased just over 40 percent in the last year. The price at the 75 percent level increased from $64/MWh to $106/MWh, or a 65 percent increase. At the 25 percent level, prices increased from $54/MWh to $68/MWh, a 26 percent increase.

Figure 36. Price Duration Curves for Mass Hub

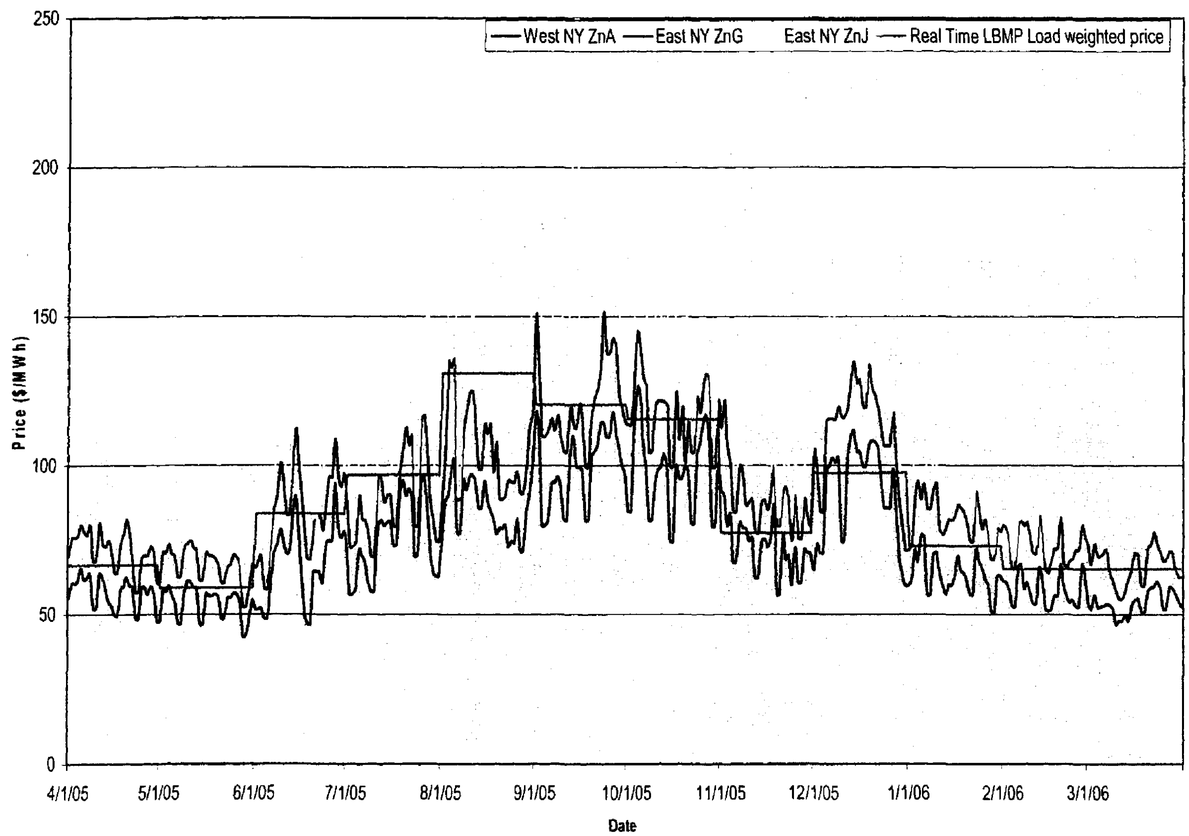


Data Source: Platt's *Megawatt Daily*.

New York ISO: NY Zone A, NY Zone G, and NY Zone J

Figure 37 shows the daily average peak hour prices for the three zones in the New York ISO. The three zones used for this comparison are Zones A, G, and J as well as the real-time Location Based Marginal Price (LBMP) load weighted price. Zone A is the western most region of New York state and includes Buffalo and to the south and west of Buffalo. Zone G is the Hudson Valley region just to the north of New York City. Zone J is the New York City area. These three regions represent three different levels of load and congestion.

Figure 37. Daily Average Peak Hour Prices for New York Zones A, G, and J, and Monthly Load weighted LBMP

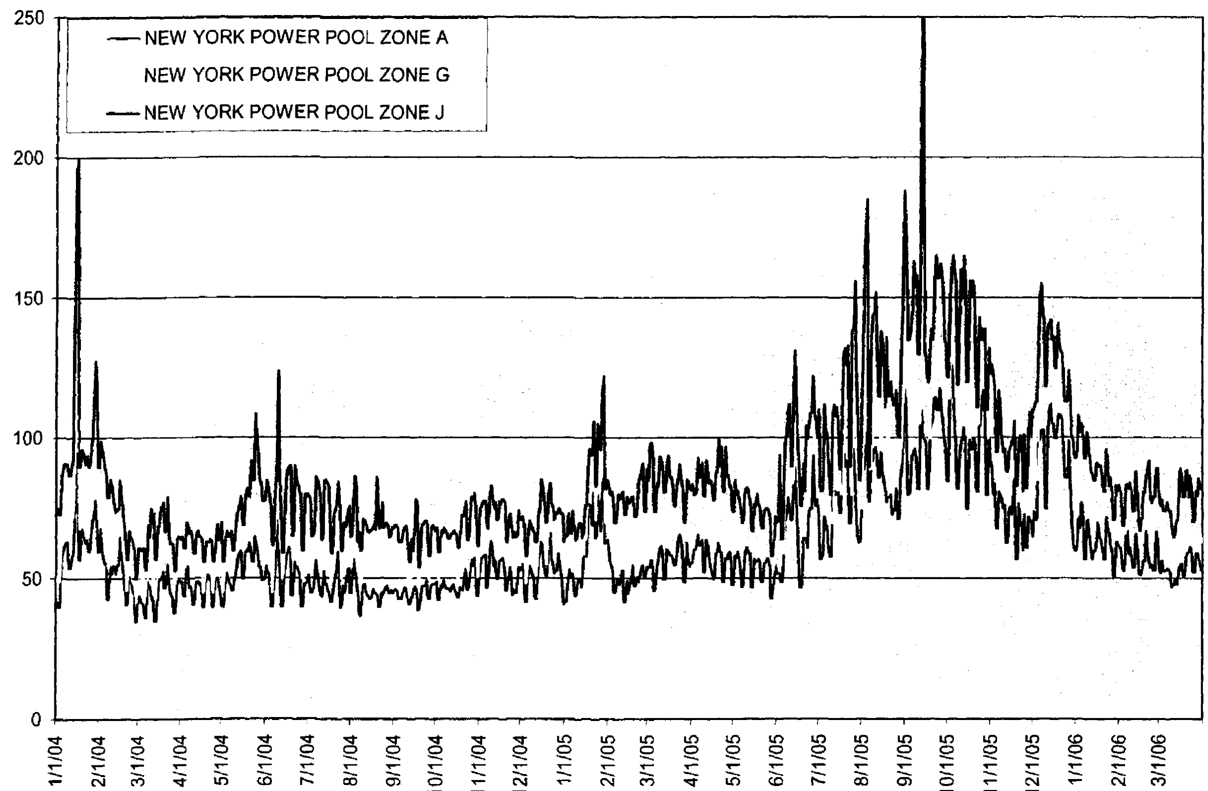


Data Source: Platt's *Megawatt Daily* NYISO for Day-ahead and Real-time prices.

The graph shows that prices in all three regions generally move together. The peaks and valleys are similar in direction, but differ in magnitude. The prices in Zone J are always the highest, while the prices in Zone A are always the lowest. As with PJM and New England, there is an evident shock caused by Hurricane Katrina and the resulting impact on natural gas prices. However, the same cannot be said for a shock from Hurricane Rita. The spike seen in mid-June, when prices soared to $250, occurred before natural gas prices increased and, therefore, cannot be explained by natural gas prices. After high electricity prices through months that are typically off-peak periods, prices have returned to the level at which they started the period.

Figure 38 extends the time frame examined to show wholesale prices for the three zones from January 2004 through March 2006. Though prices seem to be

Figure 38. Daily Average Peak Hour Prices for New York Zones A, G, and J from 1/1/2004 through 3/31/2006

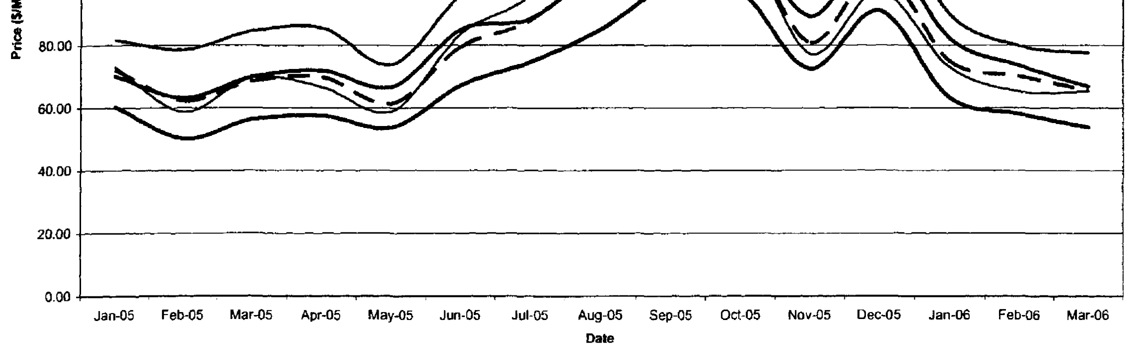


Data Source: Platt's *Megawatt Daily.*

generally fluctuating within a $20/MWh price range for any given region for most of the year, the spikes, particularly in the later part of 2005, are much higher and more sustained than at any other time in 2004. As discussed above, part of this result is likely due to higher natural gas prices. However, it is unlikely that high natural gas prices explain all of this price variation.

Figure 39 shows the average monthly prices ($/MWh) for Zones A, G, and J and the day-ahead and real-time load weighted prices. The graph shows the increases in price from July through October. After October prices drop for November, rebound in December, and fall again from January until the end of the time period examined. Zone G tends to be very close to the day-ahead average volume weighted average prices for the entire period examined. In August 2005, the ISO real-time load weighted price exceeded the prices in the trading zones.

Figure 39. Monthly Average Peak Hour Prices for New York Zones A, G, and J, and Monthly Load weighted LBMP (Real-Time and Day-Ahead Prices)

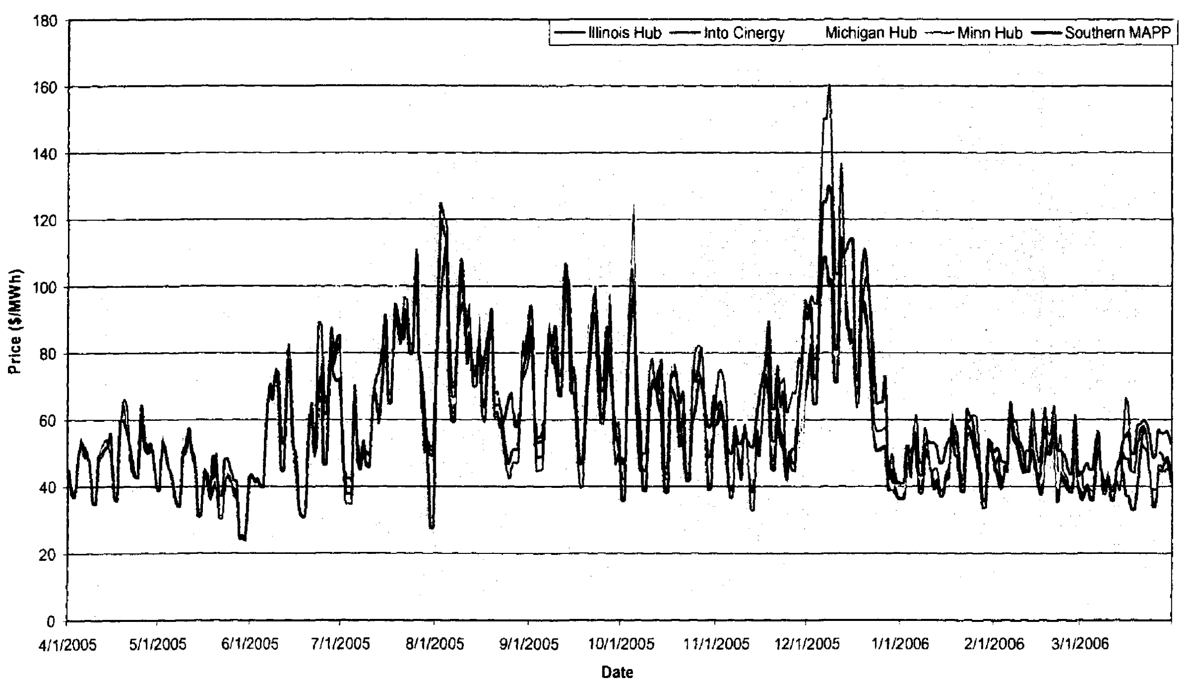


Data Source: Platt's *Megawatt Daily* for Zonal prices, NYISO for Day-ahead and Real-time prices.

MAPP South and Midwest ISO

Figure 40 shows daily average peak hour prices for the four new MISO trading hubs as well Southern MAPP. MISO introduced four standard trading hubs beginning April 1, 2005. The prices of the MISO hubs are highly correlated with one another, as well as correlated with Southern MAPP. Prices showed considerable volatility in MISO and Southern MAPP, particularly between June and December 2005. Prices generally ranged in the \$50/MWh to \$90/MWh range, but hit a low \$28/MWh (July 31, 2005, into Cinergy) and a high of \$160/MWh (December 8, 2005, Minnesota Hub). With the amount of price volatility in the region, the impacts of Hurricanes Katrina and Rita are not perceptible. Prices began to climb in all areas in late November, peaked in early December, and returned to prices in the \$40/MWh to \$60/MWh range which is similar to the prices seen at the beginning of the period examined. The price increase in December is likely due, at least in part, to high natural gas prices.

Figure 40. Daily Average Peak Hour Prices for Southern MAPP and MISO Hubs

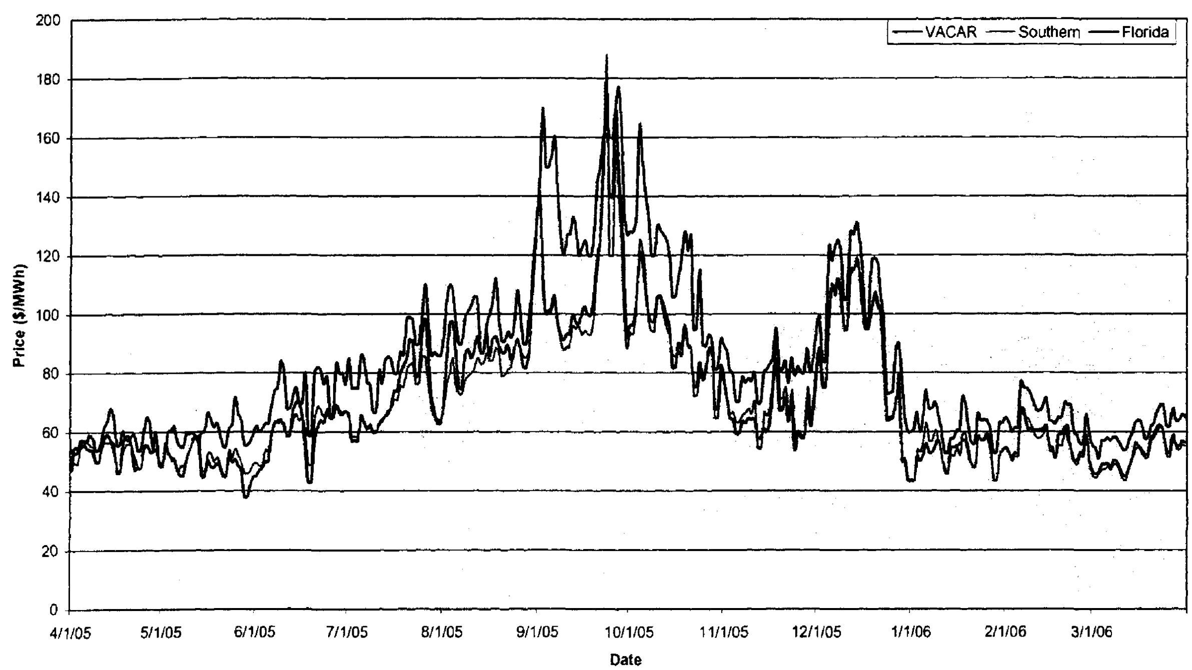


Data Source: Platt's *Megawatt Daily.*

VACAR, Southern, and Florida

Figure 41 shows the daily average peak hour prices for VACAR, Southern Co., and Florida. Florida generally showed the highest prices in any of the three areas shown in the figure. Though prices started in the $50/MWh to $60/MWh range in March 2005, prices rose steadily until September 2005. The two main spikes in 2005 were again likely in response to Hurricanes Katrina and Rita's impact on natural gas prices. All prices in this region tended to move together. After these spikes, prices began to decline until December 2006, where prices reached another brief spike before returning to a range of $60/MWh to $70/MWh. Florida saw prices in excess of $100/MWh from early September through mid October. The price spike in December is not fully explained by natural gas price increases -- since the monthly average natural gas price was lower in December than it was in November or January for Florida.[18]

Figure 41. Daily Average Peak Hour Prices for VACAR, Southern Co, and Florida



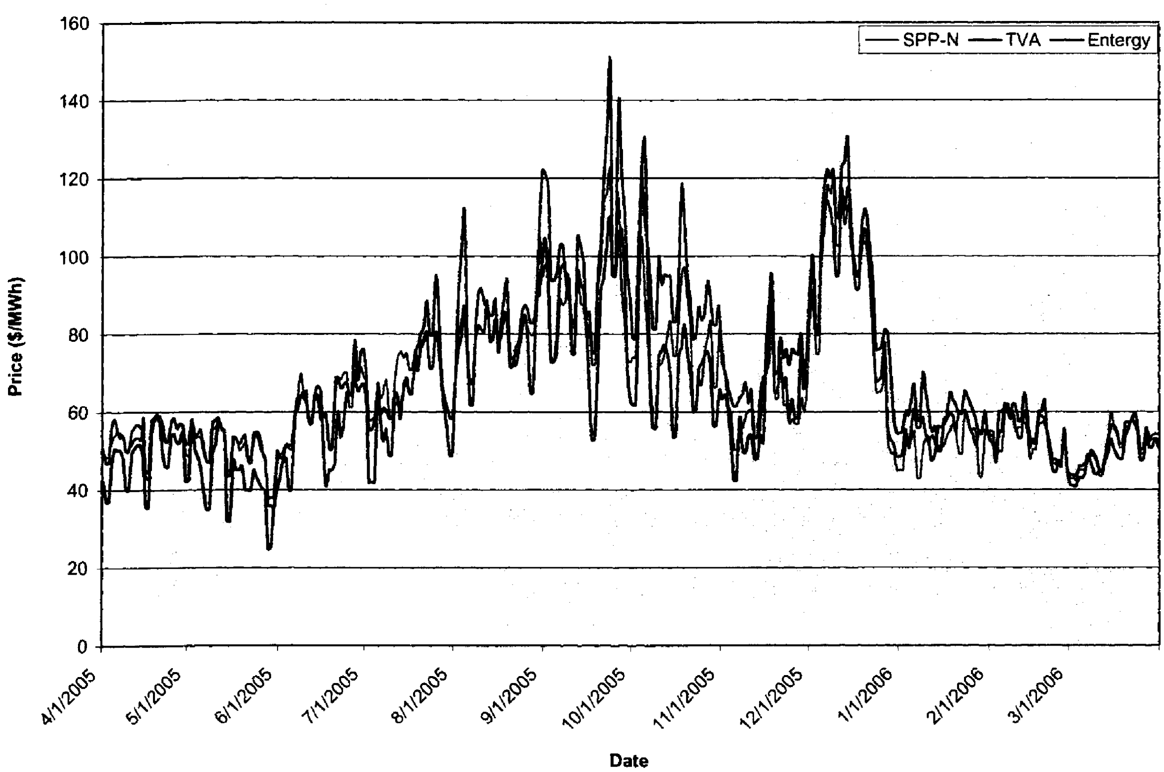
Data Source: Platt's *Megawatt Daily.*

[18] http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SFL_m.htm

TVA, Entergy, SPP North

Figure 42 shows the daily average peak hour prices for TVA, Entergy, and SPP North. Prices across the three regions tended to be correlated. Prices showed high volatility in the second half of 2005, ranging generally from $50/MWh to $100/MWh. Spikes in September and October can again be attributed to a response to Hurricanes Katrina and Rita. Natural gas prices were slightly higher in December and may account for some of the power price increase at that time. Prices stabilized in the first quarter 2006, staying in the $40/MWh to $60/MWh range.

Figure 42. Daily Average Peak Hour Prices for SPP North, TVA, and Entergy

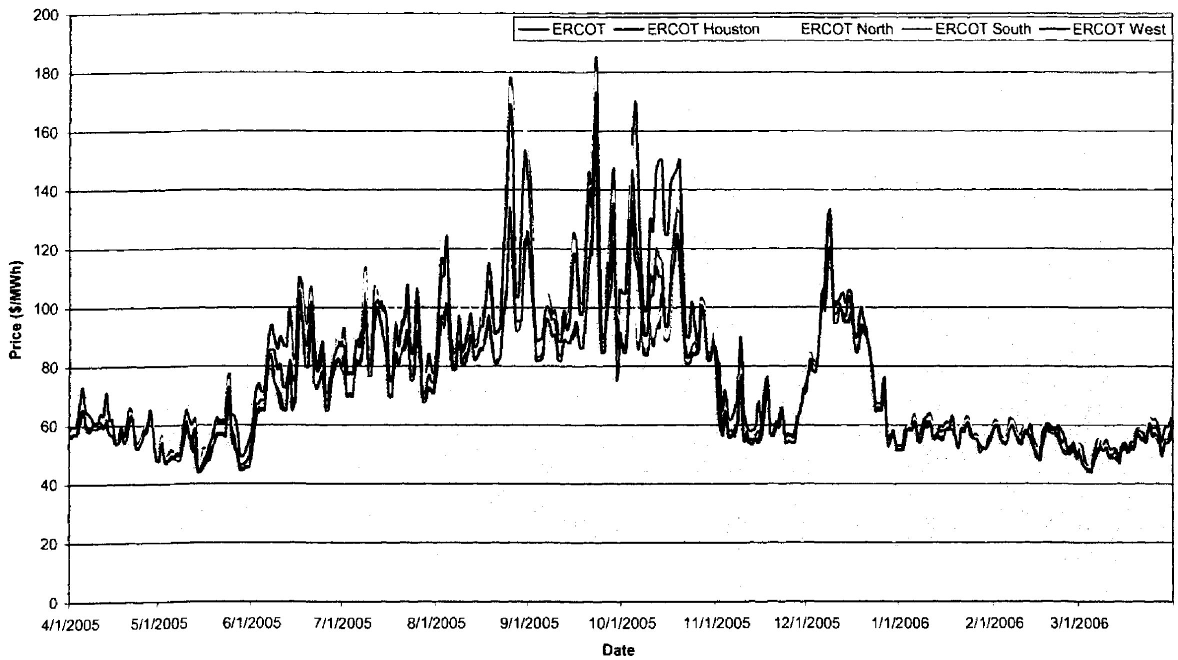


Data Source: Platt's *Megawatt Daily*.

Texas

Figure 43 shows the daily average peak hour prices for five ERCOT trading zones. The prices for all zones are correlated with one another and move in unison. Prices started in the \$60/MWh range for the second quarter of 2005, but increased to the \$80/MWh to \$100/MWh range in the third quarter. Prices increased again in the forth quarter as Texas dealt with a near miss from Hurricane Katrina and a direct hit from Hurricane Rita. The resulting power price spikes can be seen in late August and September. The spike in December can be explained, at least in part, by higher natural gas prices. Wholesale electricity prices stabilized in the first quarter of 2006, returning to the \$50/MWh to \$60/MWh range.

Figure 43. Daily Average Peak Hour Prices for ERCOT Trading Zones

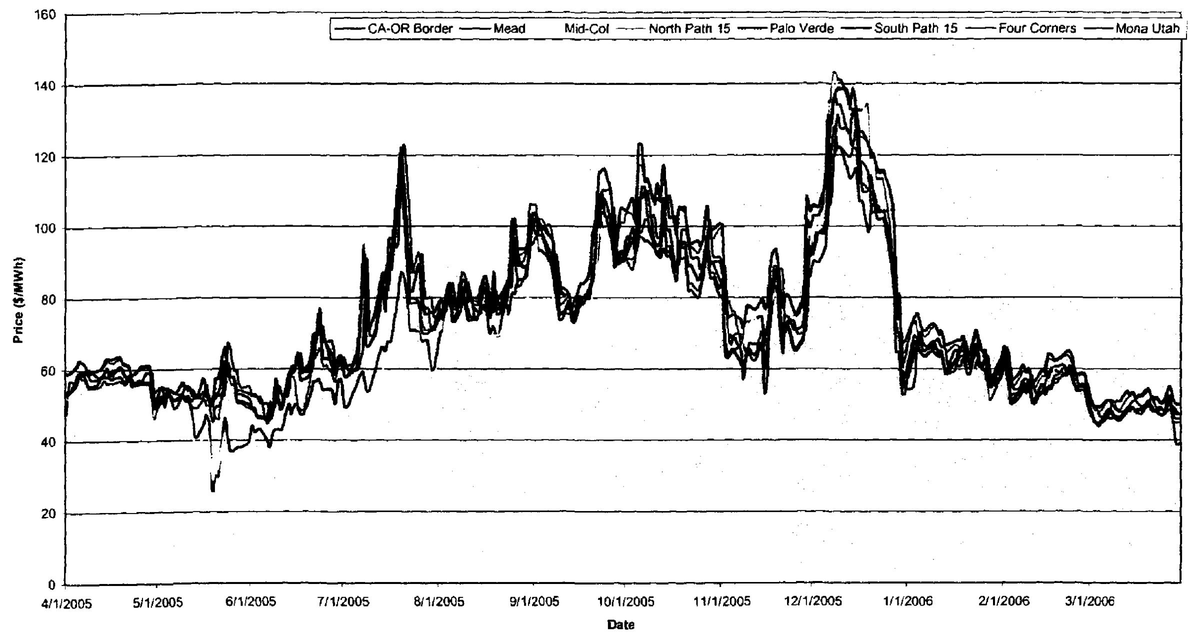


Data Source: Platt's *Megawatt Daily.*

West

Figure 44 shows the daily average peak hour prices for eight western substations. The prices are correlated with each other to a high degree, but not perfectly. Prices started slightly downward for the second quarter of 2005 before starting a steady ascent during the peak summer months. The second quarter of 2005 showed prices in the $40/MWh to $60/MWh range, with prices as low as $25/MWh. Prices in the third quarter stayed closer to $70/MWh to $80/MWh. There is a significant price spike in mid-July. The price spike in December is likely a result of natural gas price increases. California saw monthly average natural gas prices increase from $9.45 per thousand cubic feet in November to $11.65 in December. The West has seen prices stabilize and decrease in the first quarter of 2006 and prices have returned to the $40/MWh to $50/MWh range.

Figure 44. Daily Average Peak Hour Prices for Western Substations



Data Source: Platt's *Megawatt Daily*.

Summary

The impact of hot summer weather and the major hurricanes that hit the Gulf States in 2005 (and the subsequent impact on natural gas prices) resulted in the power price spikes that occurred nearly nationwide. The higher natural gas prices of December were also apparent in the country as a whole. In last year's Performance Review, wholesale power prices above $100/MWh were a rare occurrence. However, in the past year, wholesale electricity prices over $100/MWh were much more common. For example, as shown in Figure 36, at the Mass Hub, 28 percent of the hours from April 2005 through March 2006 saw wholesale prices greater than $100/MWh. This compares to less than two percent at those levels for the twelve months prior to April 2005. Regions such as the Midwest (MISO), and Southeast (Florida, Southern Co.) were seeing wholesale prices over $100/MWh for the first time in several years. However, most regions have seen prices stabilize back to ranges that coincide with the prices at the beginning of the period examined.[19]

[19] While this report is being completed, higher prices are again occurring from high summer temperatures in several regions of the country.

Part B

Retail Market Evaluation and Wholesale Market Conditions

Retail Market Evaluation

To further examine state retail markets, a comparison is made with the state bidding and auction price results and the wholesale market in the mid-Atlantic area. Also in this section, a comparison is made of the retail price trends in restructured and non-restructured states.

Figure 45 combines the mid-Atlantic bidding and auction results shown in the bar chart of Figure 8 with the PJM wholesale market prices in 2005 shown in Figure 31. The stair-step line is the monthly weighted-average PJM prices (real-time LMPs). The light-gray dashed line (constant at $44.34) is the weighted-average annual price in PJM for 2004 and the black dashed line (constant at $63.45) is the weighted-average annual price in PJM for 2005. The various color horizontal lines in the graph are the bidding and auction prices for 2004 and 2005. These are again the prices discussed above in the retail market section that were the results of the state bidding and auction procurement programs, as shown in Figure 8. In 2004, the lowest weighted-average bidding or auction price was in DC ($58.27) and the highest was in New Jersey ($65.84). There was a markup from the wholesale price in 2004 of 31 percent for the lowest bid/auction price and 48 percent for the highest 2004 bid/auction price. For 2005, the lowest weighted-average price was in Maryland ($98.65) and the highest were in DC and Pennsylvania[20] (both were $110.19). The markup ranged from 55 percent to 74 percent in 2005. Thus, not only was there a considerable increase in the bid/auction prices from 2004 to 2005, but also the proportional markup of the bid/auction prices above PJM wholesale prices was much greater. All the bidding/auction prices were higher than the highest monthly weighted-average prices of $86/MWh in August 2005. A possible contributing factor to this increased markup may be the increased volatility in the

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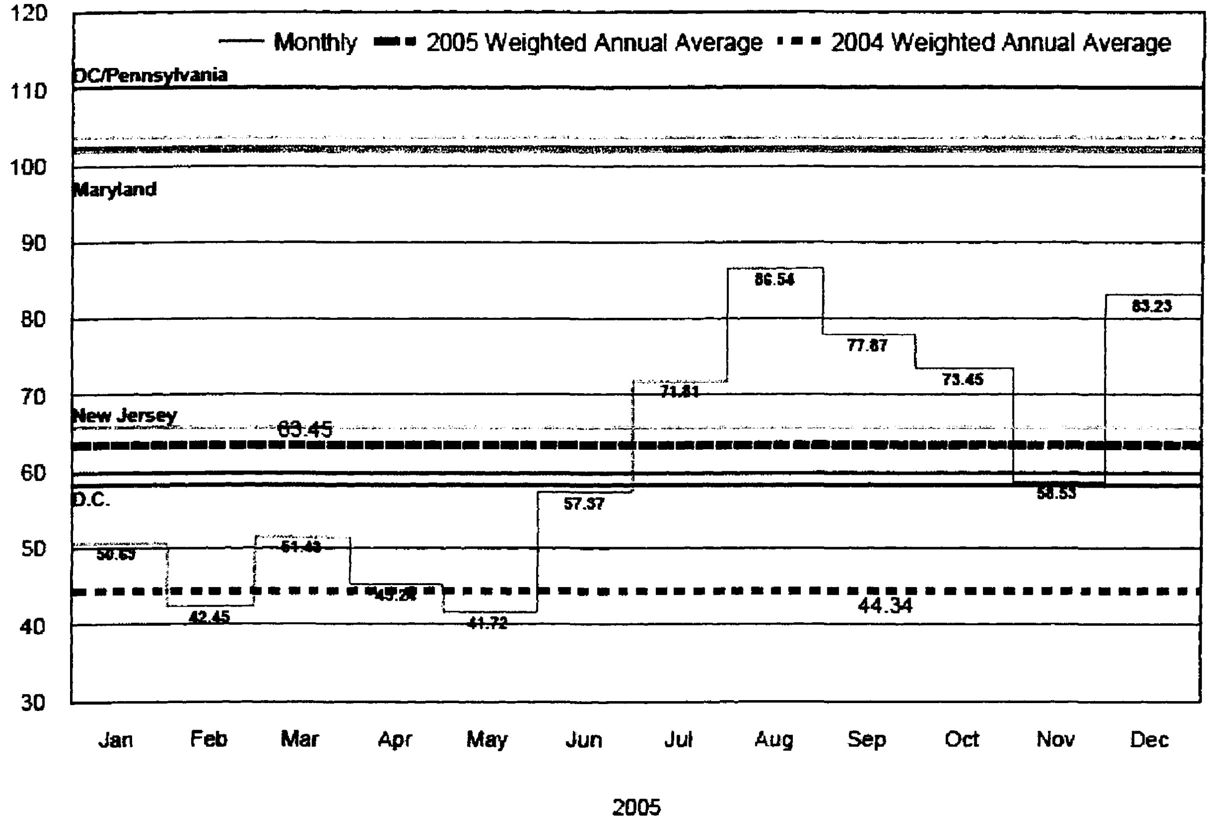
[20]Pike County Light & Power is in Pennsylvania, but is in the New York ISO wholesale market, not PJM. Prices generally are higher in the New York ISO than PJM (see the wholesale market section of this report).

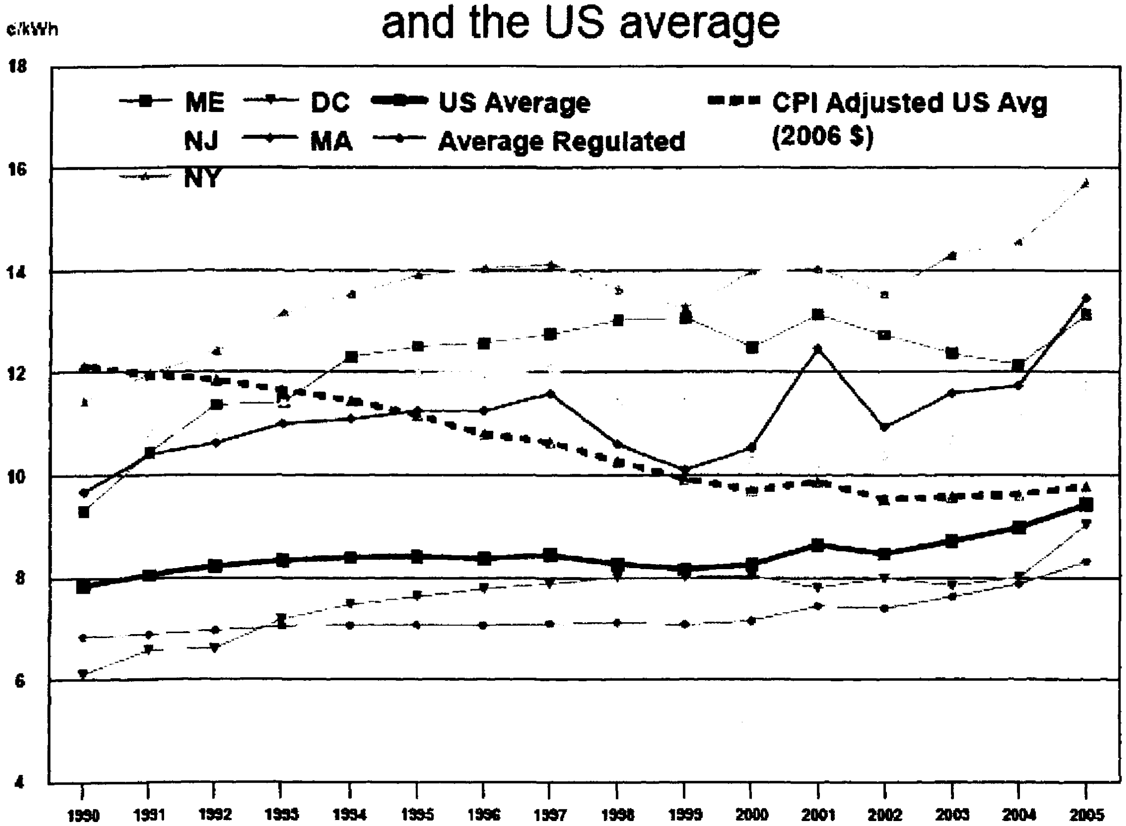
wholesale markets. The timing and extent of this variability was discussed in more detail in the wholesale market section of this report.

Figure 45. Auction/Bidding Results and PJM Market Prices



To compare states that restructured with those that did not, it first has to be decided which states to compare. States are at various stages of transition to retail access (see the Appendix to this report for details on the timing of retail access and the transition periods). Figure 46 shows the price trends for the states where the transition period has ended for most customers in the state by 2005 and where the price residential customers are paying is based on a market process (that is, procurement of power for most residential customers in the state is through bidding, auction, distribution company purchase in the wholesale market, or some other process that secures power for customers that have not selected a supplier). Four states, Massachusetts, Maine, New Jersey, and New York plus the District of Columbia fit that specification and are placed in the figure. These are the same prices that were shown and described above in the regional sections on retail markets. Also depicted is the U.S. average prices for residential customers and the U.S. average price adjusted to 2006 dollars using the Consumer Price Index (CPI).[21] Each of the individual state trends and comparison to the U.S. average price are discussed above. Added to Figure 46 also is a weighted-average price of the 30 states that remain regulated.[22]

Figure 46. Market-based and regulated states, and the US average



Averages are weighted by state residential sales. Data source: DOE/EIA.

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[21] The CPI is published by the U.S. Department of Labor, Bureau of Labor Statistics.

[22] These states are, Alabama, Arkansas, Colorado, Florida, Georgia, Iowa, Idaho, Indiana, Kansas, Kentucky, Louisiana, Minnesota, Missouri, Mississippi, North Carolina, North Dakota, Nebraska, New Mexico, Nevada (for residential), Oklahoma, Oregon (for residential), South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington,

Most of these trend lines show increasing prices in the last few years, except the U.S. average adjusted for inflation – which shows the price adjusted for inflation was falling through the 1990s and has been relatively flat since 2000. The regulated states' prices are moving at about the same rate as the U.S. average between 2002 and 2005. The national average price increased by 11.3 percent and the weighted-average price for regulated states increased by 12.3 percent and the slope of the linear regression line for that period is nearly identical, at 0.31 for the national average and 0.30 for the regulated state average. The individual restructured states shown in the figure, except for Maine, increased at a faster rate from 2002 to 2005 than the national average. New Jersey, New York and D.C. were only slightly higher than the national average at 13 percent, 16 percent, and 13 percent respectively. Massachusetts increased by 23 percent during that period.

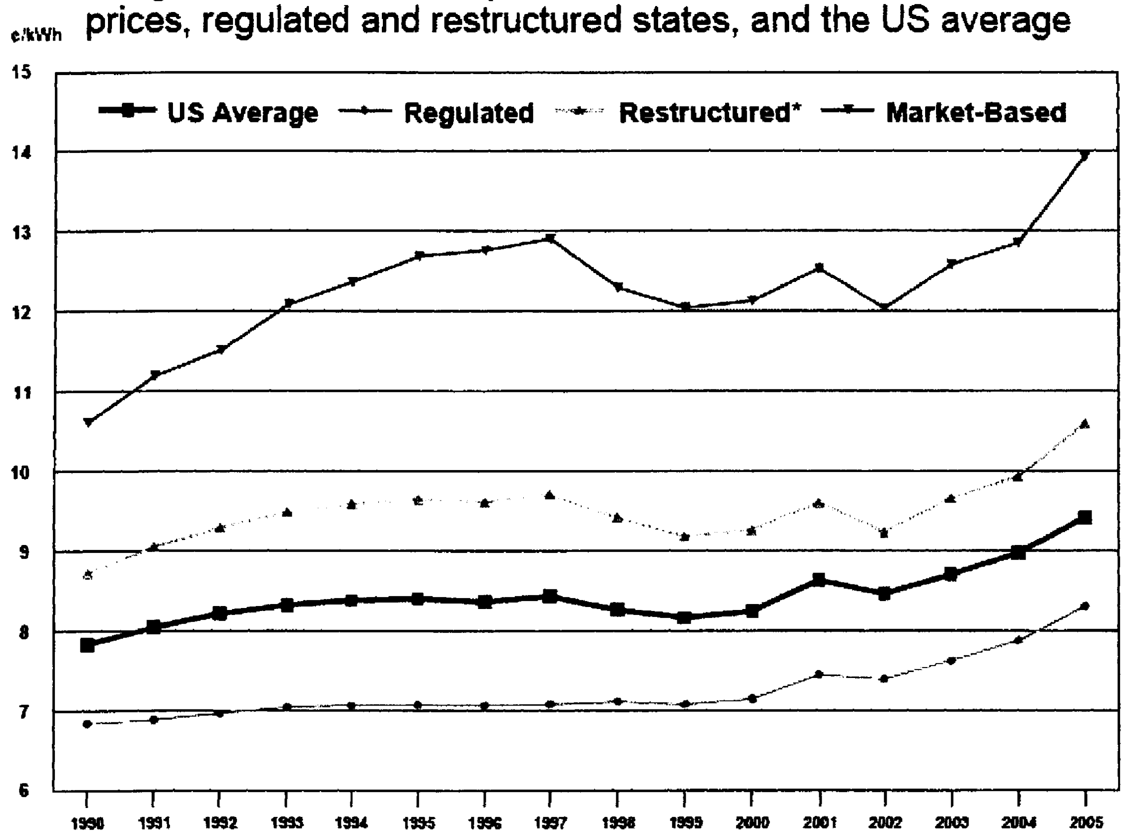
A combined weighted-average price was calculated for the individual restructured states shown in Figure 46 and a weighted-average of all states that restructured.[23] This is shown together with the U.S. average and the weighted-average of the regulated states in Figure 47. Both of the prices for the weighted-average restructured states and the weighted-average of the states where the residential customers are now paying market-determined prices increased more (at 14.9 percent and 15.8 percent, respectively) than the U.S. average and the weighted-average of the regulated states, again for the 2002 to 2005 timeframe. The slope of the linear regression line for that period is steeper at 0.44 for all restructured states and 0.60 for the states where the price caps expired. Since many of the states in the restructured group still have some form of price controls, the states where the price controls ended is a better indicator of residential customer pricing under the current restructuring arrangement in those states.

It should be noted that this analysis does not include the impact of the substantial price increases that occurred in 2006, as discussed in the retail market section.

Wisconsin, West Virginia, and Wyoming.

[23]The states included in this group of restructured states are, Connecticut, D.C., Delaware, Illinois, Massachusetts, Maryland, Maine, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Virginia. Excluded are California, which suspended its retail access, and Arizona and Michigan, which continue to control utility generation cost.

Figure 47. Residential prices for states with market-based prices, regulated and restructured states, and the US average



*Does not include Arizona, California, and Michigan. Averages are weighted by state residential sales. Data source: DOE/EIA.

In most restructured states, the electric utilities either transferred generation assets to an affiliate of the utility or the utility's assets were sold to an unaffiliated company. From DOE/EIA data,[24] in 1993, 34 states had over 90 percent of the electricity produced by utilities, while only one state had less than 50 percent of its generation produced from utility sources. As recently as 1997, only two states had less than 50 percent utility produced generation. By 2002, this picture had changed dramatically, when 14 states had less than 41 percent of electricity produced by utilities -- all of these states were states that restructured their electric utilities. Eight of these states had less than three percent of electricity produced by utilities. The utility share of state generation

[24]U.S. Department of Energy, Energy Information Administration, State Electricity Profiles 2002.

in 1993 and 2002 is shown in Table 2 for the states where the transition periods ended for most residential customers in 2006 or earlier.[25]

Table 2. Utility Share of Generation in States Where the Residential Price is Determined in the Market

	Utility Share of Generation - 1993*	Utility Share of Generation - 2002*
Delaware	92.1	2.8
District of Columbia	100.0	0.0
Maine	51.7	0.0
Maryland	96.7	0.1
Massachusetts	76.0	2.8
New Jersey	70.9	2.5
New York	85.6	31.1

*Electric utility share of total electricity generation in the state (MWh). Source: DOE/EIA.

While requiring or allowing utilities to sell or transfer generation assets may have appeared to be a good idea at the time it occurred,[26] in retrospect, this development greatly reduced state options for finding a solution to the current market developments, and makes a return to a traditional form of regulation nearly impossible in the short run.

In states where the transition period has ended and the generation portion of the customers' bills have been determined by the market, prices have increased faster than the national average and in states that did not restructure. Non-restructured states and some restructured states still in a transition period generally have increased about the

[25] This adds Delaware and Maryland that ended transition periods in 2006 for most customers to the five states examined above.

[26] Some believed that transferring the assets would reduce the chance that the utility would discriminate against and limit access for competing suppliers to reach retail customers.

same as the national average. It should be noted too that most non-restructured states remain at prices below the national average.

The evidence suggests that, at least so far, no discernable benefit can be seen for customers in restructured states once the rate caps have expired. Increasingly the evidence is beginning to now suggest that prices for customers in restructured states may actually be increasing faster than for customers in states that did not restructure.

The Wholesale Market

Figures 30 through 33 of the PJM real-time hourly prices in 2005 show the relative volatility in the hourly prices through the year, and in particular the second half of the year. The monthly weighted average prices were relatively flat through May, then began to climb in June. The increased volatility beginning in June was related to warmer weather and the resulting increased load. This increased volatility can be seen in nearly every region of the country, as the regional wholesale market prices in the figures in the wholesale section of this report also show.

A factor that is often mentioned as having a strong influence on electricity prices is the price for natural gas. The figures above also show that correlation. However, the hourly power prices and the price for natural gas are not always perfectly correlated. As can be seen in Figure 31, the volatility in PJM electricity prices began *before* the big jump in natural gas prices, which started in September and continued through the year. Also, the monthly weighted average price actually began to *fall* through November. This suggests that weather was more of a factor than natural gas prices during the early summer (when load increases) and fall (when load decreases). Natural gas prices impact electricity prices, but other factors are involved as well.

Clearly, one of those other factors is the frequency that the market price is being determined on the vertical portion of the supply curve. When the wholesale market price is set in this area, during peak hours, the price can climb quickly and to hundreds of dollars per MWh. The PJM market prices can be seen in the hourly price peaks in Figure 33. During peak hours, the demand for electricity increases to a point where the highest priced generation units may be needed to operate to meet the demand. For those hours, the price for all power is set by the highest priced marginal generation units, often units that use natural gas. The PJM Market Monitoring Unit's 2005 State of the Market Report, states that combustion turbine (CT) generation was the marginal unit 23 percent of the time during 2005. This figure 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. Therefore, for over 2,000 hours of the year CT units are determining the price. This has an impact on the overall wholesale price and eventually, on retail customers.

The price increases in the mid-Atlantic auctions have also been attributed to increasing natural gas prices. Since generation units that use natural gas are often on the margin, the bid price (not cost) for these units set the market price for that location. However, it should be noted that while natural gas units were 27.5 percent of PJM's installed capacity at the end of 2005, natural gas generated only 5.9 percent of the total generation in 2005 in PJM. *Over 90 percent of the generation during 2005 was from coal and nuclear units.* This underscores the impact of the marginal-bid price determining the market price and its impact on price that retail customers eventually pay.

The state auctions to secure supply for retail customers are interrelated with the wholesale market since suppliers and other market participants operate in or observe both the wholesale markets and the auctions for procuring retail supply. The prices that the consumers pay, therefore, is affected by the marginal price of power in the region and the frequency that the price is set in the vertical portion of the supply curve.[27] 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, the power industry is not like most competitive markets, since power supply typically has a long flat region of the supply curve that extends over most of the output range, and then turns upward and becomes nearly vertical as the maximum output is approached. This is sometimes described as a "hockey stick" shape, except, the way the supply curve is typically drawn, the handle and the head (the part that hits the puck) are about the same length. This is distinguished from the smooth upward

[27]In contrast, under traditional regulation, customers paid the average cost of power produced or purchased by their utility.

sloping supply curve usually found in economics textbooks. It is that vertical segment of the supply curve that is determining the price at many hours of the year. For consumers, this means that either an increase in demand or a decrease in supply will produce a disproportionately much larger increase in the market price.

Market Competitiveness

Electric market characteristics suggest that the market structure is not a robustly competitive one, as was hoped when restructuring began. Because of high supplier market concentration, the difficulty of entry from other firms to build new generation, limited entry from outside the area due to transmission access constraints, and existing market rules, the structure that is emerging more closely resembles that of an oligopoly, where there are only a few firms supplying all or most of the output, than a truly competitive marketplace. There is also an inelastic demand for electricity, particularly in the short-run, since customers have few practical substitutes. All these factors suggest the possibility that market conditions permit suppliers to exercise significant market power. These market structure issues were discussed at length in last year's Market Performance Review.

The frequency with which the price is determined in the vertical portion of the supply curve, as just described, also contributes to the suppliers' ability to influence the price and exercise market power. Specifically, by withholding some capacity, the supply curve is shifted to the left, meaning the vertical portion of the supply curve is reached at a lower quantity. Suppliers can also bid a very high price for a small portion of their capacity, so when demand is high and the higher priced capacity is selected for dispatch, it will set the price for all the capacity in the area. For consumers this means that higher prices are likely to result than what would occur with a more competitive structure, that is, a structure that permitted only limited ability to exercise market power.[28]

Coordinated interaction and tacit collusion among suppliers also could have particular relevance for electricity markets. The nearly continuous interaction that suppliers have in RTO markets can allow firms to excise market power and utilize anti-

[28]Market power is usually defined as the ability of a firm or group of firms to raise and maintain the product price significantly above a competitive level.

competitive bidding strategies. While transparency is important for markets to perform well, it can have the unintended result of creating markets that facilitate collusive supplier behavior. A lack of publicly available information impairs the ability to more fully assess market behavior.

There are academic papers that suggest that anti-competitive bidding strategies could happen and how it could (and perhaps actually does) happen in LMP markets like PJM.[29] While academics have been studying this issue for a few years, it is not purely an academic exercise. The 2000-2001 western power crisis demonstrated that it can and does happen. Given the fact that such strategies have been shown to be possible and successful, it is likely that suppliers are currently using strategic bidding techniques and withholding strategies to raise the price, strategies that would be less effective in a more competitive market. These strategies are particularly effective during periods of relatively high demand. In general, RTO market monitors and FERC do not examine markets for possible coordinated interaction and tacit collusion or the impact on market prices.

The price that retail customers receive, either directly from suppliers they choose or from a standard offer that is set by bidding or auction, will generally reflect what is occurring in the wholesale market. Any structural or market design flaw or significant supplier market power, will impact the resulting prices. The design and monitoring of the wholesale markets, however, is usually beyond state jurisdiction. Any required improvement in the market structure will have to be investigated and decided on by FERC.

As noted, the current wholesale market structure cannot be characterized as completely competitive. Suppliers can and do exercise an appreciable level of market power, particularly during periods of relatively high demand. This is a function of the existing market rules, supplier concentration, transmission access constraints, and other structural elements that were discussed above. Many of these can be changed through policy changes at the federal level. Others are structural and an intrinsic part of the

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[29]HyungSeon Oh, Robert J. Thomas, Bernard C. Leiseutre, Timothy D. Mount, "A Method for Classifying Offer Strategies Observed in an Electricity Market," Elsevier, July 2004.

electric supply industry. Barring a significant technological breakthrough, appropriate public policy has to be shaped to fit these structural characteristics, and not be based on what works in other industries or on notions of what should work in theory.

Appendix: Summary of State Restructuring Activity

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.		

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 ended 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 are determined by a competitive bidding (RFP) process and in the wholesale market. See details in text.		
District of Columbia	Potomac Electric Power (PEPCO)	Restructuring legislation passed 1999. Retail access began January 1, 2001.	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.		
Illinois	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. Illinois is currently planning to use an auction approach, similar to the New Jersey BGS auction, to procure power supply for customers beginning January 2007. The first auction is scheduled for September 2006.		
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%
	See details in text on Maine Standard Offer prices.		
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.
	See details in text on Maryland.		

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. 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 2003 for industrial customers, January 2005 for commercial customers, and January 2006 for residential customers.	5% rate reduction through the end of 2005 for every residential electric customer of Detroit Edison Company and Consumers Energy Company.
	In December 2005, the Michigan PSC unbundled Consumers Energy and Detroit Edison's rate schedules to make it easier for customers to compare full service and choice service options. The PSC also found that it is unlikely that there will be any new stranded costs in the future.		
Montana	Montana Dakota Utilities, Energy West Montana, and Northwestern Energy	Restructuring law passed in 1997. Retail access began 1998 (for large customers). Transition period extended to July 1, 2027 for residential customers.	2 year rate freeze began July 1998.
	A 2003 law amended the state's restructuring law by extended the transition period to July 1, 2027 for residential customers and requires NorthWestern Energy to continue to be the supplier for small customers in central and western Montana. Mid-size and large customers continue to have retail access. NorthWestern Energy owns no generation capacity. Until 2027, large customers (average monthly demand equal to or greater than 5,000 kilowatts) who are not currently being served by		

	default supply must purchase electricity from the market. Medium customers (average monthly demand equal to or greater than 50 kilowatts but less than 5,000 kilowatts) may be served by default supply or choose an alternative supplier.— but total average monthly billing demand of medium customers that choose an alternative supplier in each calendar year may not exceed 20,000 kilowatts. Small customers may be served by default supply or may be served through a commission-approved small customer electricity supply program. The total average monthly billing demand of small customers who choose to be served through a small customer electricity supply program in any calendar year may not exceed 10,000 kilowatts. As of now, there are no commission-approved small customer electricity supply programs. NorthWestern Energy agreed to a seven-year power purchase agreement with PPL Montana, the state's largest power generator, for default supply for NorthWestern's 310,000 customers (announced July 2006). Typical residential electric bills are projected to increase by approximately 7 percent beginning July 1, 2007. The contract begins July 1, 2007 when PPL's current five-year contract with NorthWestern expires. PPL's current contract provides about 55 percent of the electricity for NorthWestern customers in Montana. The new contract initially will provide about 37 percent (325 Megawatts) of the power needed to supply NorthWestern customers, and then decline gradually over the seven years. The price paid to PPL for generation will be a 40 percent increase at the beginning, and increases another 3.5 percent to 2 percent in each for the next five years. The projected increase next year for residential consumers is 7 percent because the price increase paid to PPL is only a portion of customers' overall bill. The 7 percent projected increase could be higher or lower, depending on fluctuations in the regional electricity market NorthWestern still must buy nearly one-third of its power for Montana customers on the open market. FERC ruled in May 2006 that PPL does not have "market power" in Montana, and therefore can charge market-based prices. (Sources: Montana PSC staff, NorthWestern Energy, and Gazette State Bureau, "NorthWestern Energy to pay PPL 40% more for power.")		
New Hampshire	Public Service Company of New Hampshire (PSNH), Granite State Electric Company (GSEC), Unitil Energy	Original restructuring law passed in 1996. Retail access implementation was delayed by litigation. GSEC began retail access August 1998, PSNH began	10% rate reduction for PSNH residential customers.

	Systems, Inc. (UES), and New Hampshire Electric Cooperative, Inc. (NHEC).	May 2001, and UES companies began May 1, 2003.	
	*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.
	See New Jersey summary in text for BGS auction results. FERC approved Exelon/PSEG merger in July 2005 – other agency decisions are still pending (including the NJBPU).		
New York	Central Hudson, Consolidated Edison, New York State Electric and Gas, Niagara Mohawk Power Company, Orange & Rockland Utilities, Rochester Gas and Electric	Restructuring implemented by Commission orders, no restructuring law passed. Retail access and transition periods differ by company. See below.	Discounts differed by company. See below.
	*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.		

From DOE "Status of State Electric Industry Restructuring Activity" 2003, NY State Public Service Commission, and Public Utility Law Project (PULP).[30]

Central Hudson Gas & Electric
Retail access began: September 1998
Rates frozen at 1993 levels until June 30, 2001
Full Retail Access - July 1, 2001
Sold power plants in 2000 and entered into long term buyback arrangements for most customer power needs, balance is purchased in the wholesale spot market. Major buyback contracts have expired and rates have risen.

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
The New York PSC in May 2000 adopted the Market Supply Charge/Market Adjustment Charge (MSC/MAC) methodology to flow through NYISO prices with a monthly adjustment taking into account purchased power costs including "legacy" contracts and hedges. Prices are high and volatile. Con Ed has the highest residential rates in NY, over 60% higher than the next highest rates (Orange & Rockland Utilities).[31] Con Ed testified in the last rate case it plans to buy more than 40% of energy in the NYISO spot markets.[32]

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 no longer subject to PSC rate regulation. Data on retail migration is not available. Rates that were the highest in NY state under LILCO were reduced in the transition to public ownership and have increased since the advent of the NYISO and higher natural gas prices, but not to the extent that Con Ed rates have risen.

New York State Electric & Gas
Retail access began: August 1, 1998
Rates capped until 2003, after 2003, energy rates were fixed for 2-

[30] E-mail correspondence with Gerald Norlander, Executive Director of PULP
[31] http://www.pulp.tc/Residential_Electric_Rates_7-94_-1-06_LILCO.pdf
[32] http://www.pulp.tc/CE_WholesaleElectricSupply5-5-04.pdf

year periods. 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

NYSEG rates were frozen through 2002 and since then they have set a fixed rate every two years. The energy price is based on forecast wholesale energy market prices plus a 35% adder to cover purchasing related costs (about 17.5%) and to give "headroom" for retail competitors. In the past plan (2002-2005) the company over-earned (partially as a result of the "headroom" for retail competition which did not capture significant additional market share) and more than $100 million was returnable to ratepayers as shared earnings. A rate case decision on the next plan is expected in August 2006. The company seeks to continue its fixed rate default service, the PSC Staff argues to abolish it. Even with the "headroom" (which may come back in part as shared earnings) residential customers have had stable rates in comparison with NY utilities that incorporated more NYISO spot market purchase costs in their rates.

Niagara Mohawk Power/National Grid
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. Rates were increased in a "reset" in 2005. The largest customers have prices linked to spot market prices, and gradually spot market prices will be introduced to smaller business customers.

Orange and Rockland Utilities
Retail access began May 1, 1998 O&R introduced a purchase of receivables program for competitive providers.
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 an 8.5% drop in 1997 for large industrial customers.
Full Retail Access - May 1, 1999 includes energy and

	capacity The New York PSC in May 2000 adopted the Market Supply Charge/Market Adjustment Charge (MSC/MAC) methodology to flow through NYISO prices with an adjustment for "legacy" contracts and hedges. O&R residential prices have increased and became volatile. **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 fixed annually based on wholesale energy market projections plus an adder to cover purchasing costs and "headroom" for retailers. Customers also have a variable rate option. Sold power plants and entered into long term buyback arrangements for most customer power needs, balance is purchased in the wholesale spot market. Comparatively unaffected by NYISO prices because legacy contracts still cover much of the capacity. **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	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

<table>
<tr><td></td><td>Edison, Monongahela Power Company</td><td></td><td>and lasting 3 years). AEP extended 3 years (through 2008), allowed 3% increase per year. FirstEnergy Rates are frozen until 2008 except fuel and tax adjustments.</td></tr>
<tr><td></td><td colspan="3">The Public Utilities Commission of Ohio (PUCO), fearing that a competitive base had not yet been established that would ensure consumer safety, developed Rate stabilization plans in 2003. American Electric Power (AEP), FirstEnergy, Duke Energy Ohio (formerly Cincinnati Gas & Electric Company), and Dayton Power & Light (DP&L) all filed rate stabilization plans (RSP). Rate Stabilization Plans filed are as follows:[33]

AEP:
Three years: Jan 1, 2006-Dec 31, 2008
Generation rates will increase 3% per year for Columbus Southern Power customers and by 7 percent for Ohio Power customers. Distribution rate remain fixed through 2008. $14 million to be used for low-income assistance and economic development. Allows AEP to request additional rate increases for environmental and security expenses as needed.

Duke Energy Ohio:
Three years: Jan 1, 2006-Dec 31, 2008 for residential. Jan 1, 2005-Dec 31, 2006 for non-residential.
Generation rates are allowed to increase. These increases can be avoided by 25% of residential consumers that shop for a competitive supplier. Distribution rates will increase by 4.4%.

DP&L:
Five years: Jan 1, 2006-Dec 31, 2010
Generation rate increase capped at 11% over the five year period. Residential customers will receive a 7.5 % discount on bills from 2006-2008. Distribution rates will remain fixed until 2008. If rates fall, PUCO can cancel RSP and order DP&L to use market based rates.</td></tr>
</table>

[33] This information was obtained from the OCC site for Electric Choice and can be found at http://www.pickocc.org/electric/echoice.shtml.

FirstEnergy:
Three years: Jan 1, 2006-Dec 31, 2008
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 and the RPS rates were then used. The PUCO will hold additional auctions in the future to continue to test the market for lower generation rates.

FirstEnergy also agreed to a Rate Certainty Plan with the OCC and cities of Akron, Cleveland, and Toledo to continue to stabilize prices through 2008.

A second auction in early 2006 to supply 9,000 MW of power in 2007 and 2008 to FirstEnergy's customers was cancelled after no competitive supplier submitted applications to participate.

Transmission rates for all companies may vary during each utility's respective rate stabilization periods.

The Ohio Consumers' Counsel (OCC) filed suit against the PUCO in the Supreme Court of Ohio, claiming that the Rate Stabilization Plans (RSP) of AEP, FirstEnergy, Duke (formerly CG&E), DP&L violated state law. The OCC won the suite against AEP and FirstEnergy.[34] The Supreme Court of Ohio agreed with the OCC's case against FirstEnergy and AEP, remanding the RSPs to the PUCO. The case against Duke is still open. The case against DP&L is open, and only in the briefing stage.

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. The PUCO approved the transfer of Monongahela Power's service territory to AEP on Nov. 9, 2005.

[34] http://www.pickocc.org/news/2006/07052006.shtml
[35] http://www.pickocc.org/news/2006/05102006.shtml

	The Supreme Court of Ohio also found that deferring transmission charges to a later date by FirstEnergy and DP&L was in violation of the rate cap.[35] *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.		
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.		

Sources: * indicates source as: http://www.eere.energy.gov/femp/program/utility/utilityman_staterestruc.cfm other information from corresponding state public utility commissions or others sources as indicated.

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 Regional Transmission Organizations ("RTO"), 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 a small portion of Dominion Virginia Power

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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

("Virginia Power" or "DVP") customers in northern Virginia with a limited renewable resource and another supplier recently acquired four large Delmarva customers. Staff is not aware of any other electricity supply offers.

Despite modifications to the Commission approved pilot programs of Virginia Power 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.

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energy.

[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 electricity consumers on January 1, 2004. Allegheny Power ("AP" or "APS")[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. One CSP is fully registered with Delmarva and has just recently enrolled its first customer.

Virginia Power's service area was fully opened to retail choice on January 1, 2003. To date, six CSPs and five 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 1,339 customers as of August 11, 2006. 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.

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-five electric and natural gas competitive service providers ("CSP") 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 local distribution company's ("LDC") 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.

Currently, six CSPs, Dominion Retail, Pepco Energy Services, Washington Gas Energy Services, Commerce Energy, ECONnergy Energy Company and WPS Energy Services are

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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

fully registered with DVP. Additionally, five aggregators are fully registered with DVP, American PowerNet Management, Independent Energy Consultants, Intel-Audits, WPS Energy Services, and the City of Fairfax.

One supplier, Washington Gas Energy Services ("WGES"), is fully registered with Delmarva. The other electric utilities do not have any registered suppliers at this time to serve customers in Virginia.

("VAEDT"). Further information may be found at http://www.vaedt.org .

Licensed Competitive Service Provider/Aggregator as of August 11, 2006

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
Hess Corporation	C, I	WG, SG	Electric, natural gas and aggregation (E&G)
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	R, C, I	WG, SG, CGV	Electric, natural gas and aggregation (E&G)
Utility Resource Solutions, LP	R, C, I		Natural gas
Old Mill Power Company	R, C, I		Electric, natural gas and aggregation (E&G)
Metromedia Energy, Inc.	C, I	WG	Natural gas
Stand Energy Corporation	C, I	WG	Natural gas
Intel-Audits, Inc.	C, I	DVP	Aggregation (E)
AOBA Alliance, Inc.	C		Aggregation (E&G)
UGI Energy Services, Inc.	C, I	WG	Natural gas
Constellation NewEnergy, Inc.	C,I	WG, SG	Electric, natural gas and aggregation (E&G)
City of Fairfax	R	DVP	Aggregation (E)
American PowerNet Management, LP	C,I	DVP	Aggregation (E&G)
JP Communications Group	R,C		Aggregation (E)
ECONnergy Energy Co., Inc.	R,C	DVP, WG	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 and natural gas
Delta Energy LLC	C,I		Natural gas and aggregation (G)
Renaissance Energy, LLC	C,I		Electric and natural gas aggregation
New Era Energy, Inc.	R, C, I		Aggregation (E)

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 1,339 residential and 19 commercial customers are enrolled with PES. No industrial customer has yet chosen a competitive electricity service provider.

Delmarva has recently experienced its first switching activity with WGES enrolling four large commercial customers in Virginia. This followed Delmarva's request to increase its fuel factor by almost 50% in 2006 for its Virginia customers on the Eastern Shore. However, the Commission Order of June 19, 2006 in Case PUE-2006-00033, permitted an increase of about 25%, still a significant increase to customers.

Customer Participation

Pepco Energy Services began serving retail access customers in January 2002 and is currently the only CSP serving residential customers. Out of approximately 3.2 million customers in Virginia who currently have the right to choose an alternative supplier of electric energy, about 1,339 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 August 11, 2006.

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	1,937,804	231,383	1,339	19
AEP-VA	432,136	70,358	0	0
AP	80,910	14,641	0	0
DPL	18,654	3,233	0	4
NOVEC	119,506	8,169	0	0
REC	85,765	4,558	0	0
SVEC	28,359	4,902	0	0
CEC	8,506	1,620	0	0
A&N	10,257	787	0	0
BARC	11,480	585	0	0
CVEC	28,784	2,828	0	0
CBEC	5,710	588	0	0
MEC	28,802	1,731	0	0
NNEC	16,176	1,052	0	0
PGEC	9,104	1,036	0	0
SSEC	48,854	2,171	0	0
TOTAL	2,870,807	349,642	1,339	23

* Customer numbers as of December 31, 2005

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.

Functional Unbundling

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 on an annual basis, but terminating on June 30, 2007. 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 original forward price method considered prices at two delivery or receipt points (Cinergy and PJM Western Hub) 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.

[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.

In 2005, the Commission further modified the forward price methodology by restricting consideration of forward prices to the PJM Western Hub delivery point.

Projected market prices for DVP during 2006 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 2006; therefore, wires charges are not applicable to any DVP customers that choose to take service from a CSP during 2006. On July 1, 2006, DVP submitted an application to potentially impose wires charges for the first half of 2007. 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.

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 2006, none of the Cooperatives are collecting wires charges.

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.

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 or cooperatives imposed a wires charge component within its prices-to-compare during 2006.

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[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

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 2006 price-to-compare values for the subject investor-owned utilities are:

Customer Class	DVP	APCo	PE	Delmarva
Residential	6.078¢/kWh	3.714¢/kWh	3.87¢/kWh	6.47¢/kWh
Small Commercial	5.699¢/kWh	3.535¢/kWh	3.96¢/kWh	7.00¢/kWh
Large Commercial	5.435¢/kWh	4.053¢/kWh	3.90¢/kWh	Not applicable
Small Industrial	4.629¢/kWh	3.430¢/kWh	3.55¢/kWh	6.73¢/kWh
Large Industrial	4.217¢/kWh	3.249¢/kWh	3.34¢/kWh	6.00¢/kWh
Churches	6.651¢/kWh	3.452¢/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 2007. 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

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Cooperative.

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.

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

CONSUMER EDUCATION

No significant changes to the Virginia Energy Choice ("VEC") consumer education program were implemented in the past year. Three years ago, the scope of the program was limited to maintaining a toll-free information line and website that give consumers basic facts on the restructured energy market in Virginia. For those persons needing more detailed explanations, they may request a call from the SCC staff or send their questions to a special VEC email address. The program distributed over 2,329 VEC consumer guides and other publications in the fiscal year ending June 30, 2006.

The VEC toll-free information line (1-877-YES-2004) is supported by an automated system that gives callers the choice of listening to a brief recording on restructure, leaving address information to receive consumer education materials, or leave a message for SCC staff. The information line received 5,312 calls in the last fiscal year. In an average month, 17 callers leave messages for SCC staff to respond to general questions about the status of retail choice in Virginia and energy-related topics.

The VEC website (www.vaenergychoice.org) received between 7,700 and 8,500 individual visits per month in the last fiscal year. Web visitors may read extensive information on the changes to the energy market in Virginia, print information sheets, or request consumer guides be mailed to them.

Rising electricity and natural gas prices in the past year caused a number of consumers to turn to VEC for information on competitive service providers offering energy supply service at a lower price than the incumbent utilities. Staff noted an increased number of calls and emails with a negative tone when consumers learned of the lack of electric choice and limited natural gas choice.

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.

Following several meetings and submission of comments, the proposed rules appeared acceptable and issues regarding the "reasonable margin" and "administrative costs" components of market-based costs clearly became the most controversial. A work group discussion to attempt to resolve the wide range of opinions among the parties regarding the two large outstanding issues was held on July 19, 2005. As parties could not agree on how to

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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 .

resolve the outstanding issues, and the result of zero wires charges for 2006, requests were submitted to defer ruling on the contested issues. On January 4, 2006, the Commission issued its Order Adopting Rules and Regulations regarding the Rules Governing Exemptions to Minimum Stay Requirements and Wires Charges as set forth in the Staff's Report. The Order also deferred any finding regarding the contested issues until such time the marketplace became conducive to implement these exemption programs. The Commission also submitted the Rules to the Registrar's Office to be codified in Chapter 313 (20 VAC 5-313-10 et seq.) of Title 20 of the Virginia Administrative Code.

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, seven additional aggregators have been licensed by the Commission, while four others chose not to renew their aggregator's license in 2006.

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. 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. Recently the Institute for Electrical and Electronic Engineers ("IEEE") has completed its work on establishing a national standard for distributed generation interconnections ("IEEE-1547").

On August 8, 2005, the U.S. Congress enacted the Energy Policy Act of 2005, P.L. 109-58, 119 Stat. 594 (the "Energy Policy Act"), to develop, among other things, a new federal PURPA standard that would, if adopted, require each electric utility to make available, upon request, interconnection service to any customer that the utility serves. Section 1254(a) of the Energy Policy Act amends § 111[19] (d) of PURPA, 16 U.S.C. § 2621(d), by adding the following standard for consideration:

> (15) INTERCONNECTION - (A) In this paragraph, the term 'interconnection service' means service to an electric consumer by which an on-site generating facility on the premises of the electric consumer is connected to the local distribution facilities.
> (B)(i) Each electric utility shall make available, on request, interconnection service to any electric consumer that the electric utility serves.

[19] Section 111 of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601et seq. ("PURPA"), requires each state regulatory authority, with respect to each electric utility for which it has ratemaking authority, to consider certain federal standards established by PURPA for electric utilities within its jurisdiction. Each such state regulatory authority is required to determine whether or not it is appropriate, to the extent consistent with otherwise applicable state law, to implement these standards.

> (ii) Interconnection services shall be made available under clause (i) based on the standards developed by the Institute of Electrical and Electronics Engineers entitled 'IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems' (or successor standards).
> (C)(i) Electric utilities shall establish agreements and procedures providing that the interconnection services made available under subparagraph (B) promote current best practices of interconnection for distributed generation, including practices stipulated in model codes adopted by associations of State regulatory agencies.
> (ii) Any agreements and procedures established under clause (i) shall be just and reasonable and not unduly discriminatory or preferential.

Section 1254(b) of the Energy Policy Act requires each state regulatory authority to consider whether or not the interconnection standard would be appropriate for implementation However, a state regulatory authority is not required to consider and determine whether or not such standard is appropriate to be implemented if, prior to the August 8,2005, enactment of the statute: (1) the state implemented the standard or a comparable one; (2) the state regulatory authority conducted a proceeding to consider implementation of the standard or a comparable one; or (3) the state legislature voted on the implementation of the standard or a comparable one.

By Order dated May 10, 2006, entered in Case No. PUE-2006-00064, the Commission is seeking comments with regard to what action, if any, it needs to take with regard to interconnection standards. This proceeding is ongoing at the time of this report.

Chapter 470 of the 2006 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. As amended, eligible customer-generator means a customer that owns and operates, or contracts with other persons to own, operate, or both, an electrical generating facility that: (i) has a capacity of not more than 10 kilowatts for residential customers and 500 kilowatts for nonresidential customers; (ii) uses as its total source of fuel renewable energy, as defined in § 56-576; (iii) is located on the customer's premises and is connected to the customer's wiring on the customer's side of its interconnection with the distributor; (iv) is interconnected and operated in parallel with an electric company's transmission and distribution facilities; and (v) is intended primarily to offset all or part of the customer's own electricity requirements.

In response to this statutory change, by Order dated June 23, 2006, the Commission initiated Case No. PUE-2006-00073. In its June 23, 2006 Order, the Commission noted that the current Net Energy Metering Rules[20] must be revised first to reflect an expansion of the definition of eligible customer-generator such that it will include not only a customer who owns and operates an electrical generating facility, but also one who contracts with other persons to own, operate, or both, the electrical generating facility. In addition the Commission noted that the Net Energy Metering Rules must also be revised to reflect the expansion of the types of permissible fuels for the electrical generating facility. In addition to previously permitted solar, wind, and hydro, energy from waste, wave motion, tides, and geothermal power are now permissible fuels. It is also now required that not only must the generator be located on the customer's premises, but must also be connected to the customer's wiring on the customer's side of its interconnection with the distributor.

Comments on the Commission's proposed amended Net Metering Rules are due by August 21, 2006.

Business Practices

[20] 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 .

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.[21] NAESB is accredited as a standards-setting body from the American National Standards Institute, charged by the Federal Energy Regulatory Commission ("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 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.[22] Approval of six additional facilities was granted by this Commission with capacities totaling 3,865 MW. One of those facilities with a capacity of 680 MW withdrew its certificate. The remaining five projects have not yet been developed. Currently, one application for a 39 MW wind turbine facility is pending before this

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

[22] 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.

Commission. The table at the end of this section provides further detail regarding the applications.

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 likely include physical construction and enhancement as well as contractual and financial alternatives. Additional discussion of such issues will be addressed in the following sections of this report regarding RTO Development and FERC Dockets.

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 was completed and energized on June 25, 2006. Certificates for two shorter transmission lines were granted in 2005 and four certificate applications are currently pending before the Commission. Additionally, several new natural gas pipelines are now in service or have been approved.

Although applications have not been filed with the Commission, several major generation and transmission projects by Virginia utilities have been proposed or are currently being evaluated. As a result of its Regional Transmission Expansion Planning process focusing on 2011 needs, PJM has approved two proposed transmission projects as the best solutions for addressing regional transmission reliability concerns (including Northern Virginia) by improving west-to-east power flows. These include an APS 500kV transmission line project from Pruntytown, West Virginia to Mt. Storm and a joint APS/DVP 100-mile 500 kV transmission line from Mt. Storm to Loudoun County in Virginia. The cost of these lines will be allocated to beneficiaries in neighboring states (Maryland, Pennsylvania, and Washington, D.C.) as well as to Virginia. PJM has also approved two DVP proposed projects, a 56-mile 500 kV Carson to Suffolk line and a 26-mile 230 kV Suffolk to Fentress line, to address reliability concerns in Eastern Virginia.

It should be noted that AEP recently proposed a new 765 kV transmission line stretching from West Virginia to New Jersey. AEP states that the proposed line is designed to relieve transmission congestion and enhance west-to-east power flows and reliability. However, PJM has not evaluated this proposal or its potential impacts with respect to the approved APS and DVP transmission projects discussed above.

Dominion Resources is studying the possible construction of up to two more nuclear generating units at DVP's North Anna Power Station. In 2003, the Company filed an application with the Nuclear Regulatory Commission ("NRC") for an early site permit. An NRC decision on the application is expected during 2007.

DVP is the lead entity of a consortium (including APCo, ODEC, Blue Ridge Power Agency, and the Virginia Municipal Electric Association Number 1) that is currently evaluating the construction of a 500 to 600 MW Circulating Fluidized Bed Coal Plant in Wise County, Virginia pursuant to § 56-585 G of the Restructuring Act.

In the Petition of Virginia Electric and Power Company for Certain Initial Determinations with Regard to Virginia Code § 56-585 G, Case No. PUE-2006-00075, Dominion Virginia Power has requested that the Commission make certain legal determinations relating to that company's possible construction of a coal-fired generation facility in the coalfield region of Virginia.[23] Significantly, the Petition before the Commission is not an application to construct and operate any such facility. Instead, the Petition seeks *preliminary* determinations relating to the interpretation and application of § 56-585 G of the Code of Virginia.

Specifically, Dominion Virginia Power has requested that the Commission issue an order that (1) approves a particular calculation and implementation of an Allowance for Funds Used During Construction rate for the period during the planning and construction of a Plant pursuant to Virginia Code § 56-585 G, (2) approves a "risk premium" during the commercial operation of the facility, and (3) grants exemptions from certain portions of the electric utility bidding rules found at 20 VAC 5-301-10 *et seq.* The Commission issued an Order for Notice and Hearing on July 13, 2006; a hearing on these issues is slated for October 17, 2006.

AEP is proceeding with plans to construct at least two 600 MW Integrated Gasification Combined Cycle clean-coal plants outside of Virginia (most likely in Ohio and/or West Virginia) with targeted in-service dates of 2010 and 2013. AEP has signed an agreement with

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[23] The Company states in its Petition that the preliminary site selected for the Coal Plant is in Virginia City, Virginia, just outside of St. Paul, Virginia, in Wise County. The Coal Plant's estimated output will be 500-600 MW, fuel supply for the Coal Plant will consist primarily of run-of-mine coal from various mines in the coalfield region of the Commonwealth, and the Plant, a described, will also allow the use of opportunity fuels such as coal waste and biomass (wood chips). The preliminary site is not within Dominion Virginia Power's service area

General Electric Energy and Bechtel Corporation to begin the front-end engineering and plant design process.

Summary of Construction Activity in Virginia
As of August 1, 2006

Company/Facility	*Size*	*Location*	*Docket*	*Fuel*	*C.O.D.**	*Hearing*	*Order*
New power plants in operation							
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						
Power plants granted SCC certificates							
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						
New power plants that have applied for an SCC certificate							
Highland New Wind Development	39 MW	Highland County	PUE-2005-00101	19-wind	fall 07	11/8/05	pending

*Commercial Operation Date

Company/Facility	*Size*	*Location*	*Docket*	*C.O.D.*	*Order*
Transmission lines					
APCo	765 kV-90 mi	Wyoming-Jackson's Ferry	PUE970766	6/06	Completed and energized 6/25/06
DVP	230 kV- 4 mi	Loudoun	PUE010154	5/06, 5/07	6/27/02 approved, under construction
DVP	500 kV-8 mi	Fauquier	PUE-2004-00062	5/07	7/15/05 approved, under construction
DVP	230kV – 11.8 mi	Chesterfield	PUE-2004-00041	11/06	9/28/04 approved, under construction
DVP	230kV – 8 mi	Loudoun	PUE-2002-00702	12/08	10/8/04 approved, under construction
DVP	230kV – 7 mi	Norfolk	PUE-2004-00139	5/07	8/29/05 approved, under construction
DVP	230kV- 16 mi	Loudoun	PUE-2005-00018	6/08	pending
DVP	230kV – 6 mi	Virginia Beach	PUE-2006-00040	12/06	pending
DVP	230kV – 16 mi	Fauquier & Prince William	PUE-2006-00048	5/09	pending
NNEC	230kV – tap	King George	PUE-2006-00071	9/06	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, implemented 3/1/02.
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, Withdrawal from MISO effective September 1, 2006.
AEP (PJM West)	PUE-2000-00550	Order of 8/30/04 approving transfer of operation of transmission facilities to PJM West, implemented 10/1/04.
DVP (PJM South)	PUE-2000-00551	Order of 11/10/04 approving transfer of operation of transmission facilities to PJM, implemented 5/1/05.

RTE Development and Competitive Conditions

Section 56-579 G of the Restructuring Act requires the Commission to report annually "its assessment of the success in the practices and policies of the RTE [regional transmission entities] facilitating the orderly development of competition in the Commonwealth." Earlier reports focused on the development of RTEs. In the 2005 report we noted that all of Virginia's investor-owned electric utilities had shifted management of their transmission facilities to an RTE. APCo, Allegheny Power, Delmarva and Dominion are participating in PJM[24] and Kentucky Utilities is currently participating in MISO.[25] This report will discuss further developments in RTE participation and the impacts of RTE operations on the development of competition.

Kentucky Utilities

Kentucky Utilities ("KU") doing business in Virginia as the Old Dominion Power Company transferred control of its transmission facilities to MISO on February 1, 2002. On October 7, 2005, KU filed an application with the FERC and the Kentucky Public Service Commission for approval of withdrawal from MISO. In its application, KU raised concerns regarding significant cost issues associated with its continued participation in MISO. Many of these concerns were associated with the design and operation of MISO's energy market. KU believed that participation in the MISO energy market had resulted in the suboptimal economic dispatch of its generating units, which had a detrimental impact on its fuel expenses. In short, KU argued that withdrawal from MISO would result in a significant net economic benefit for the company and its

[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

customers. On March 17, 2006, the FERC conditionally approved withdrawal of KU from MISO. The Kentucky Commission approved KU's withdrawal from MISO on May 31, 2006. Subject to a few ongoing non-controversial regulatory matters, KU is now scheduled to withdraw from MISO's energy market on September 1, 2006. At that same time, KU will contract with the Tennessee Valley Authority to act as its reliability coordinator and with the Southwest Power Pool to act as its open access transmission tariff administrator. It should be noted that §56-580 G relieves KU of any obligation to be in an RTO pursuant to Virginia law.

Competitive implications of PJM and the PJM markets

Virginia's largest electric utilities have now been integrated into PJM for at least one year. Consequently, the Commission Staff has now begun to gather and review data to facilitate a better understanding of the implications of PJM membership on the development of competition and to assess the competitiveness of the electric utility industry in the Commonwealth. This task is extremely difficult given the sheer volume of PJM's operating rules and the complexities associated with the transmission grid. In conjunction with this effort, the Staff collected certain information, reviewed post-RTE integration reports submitted by the utilities and PJM, and reviewed PJM's State of the Market Report. Additionally, the Staff is seeking Virginia specific information regarding certain indicators of market concentration and competitive conditions. The Staff has also sought additional information needed to assess the various bidding strategies of generators participating in the PJM energy markets. While the Staff has not yet obtained all the requested information it continues to pursue additional data from PJM.

KU's transmission facilities on February 1, 2002.

In the absence of that information, the Staff has begun to review other available information in conjunction with its assessment of the effectiveness of the PJM markets in Virginia. The following discussion represents some of the Staff's preliminary observations derived from that assessment.

Prices associated with PJM's energy markets are based on a system of locational marginal prices ("LMP"), where the price for a given time increment is based on the bid submitted by the last unit needed to operate during that time period, as selected through a competitive auction. All units selected during this time interval receive the same payment based on the last selected bid, i.e. the market clearing price. Since the various components of the transmission system have differing levels of capacity, PJM has to control flows across its system so that no single transmission element becomes overloaded. PJM controls transmission flows by dispatching generating units based on the bids of the units and physical conditions. The results of this dispatch are the basis for LMPs throughout the PJM region. LMPs within PJM are typically not uniform for each time interval since the PJM grid cannot always reliably accommodate a free flow of power throughout the entire PJM footprint.

During these constrained periods, market clearing prices begin to separate throughout PJM to reflect the accessibility of load to generation or conversely of generation to load. In effect, the LMP system recognizes that PJM's electricity market segments into smaller markets as the ability of the transmission grid to reliably accommodate economic transfers of power decreases. Unfortunately, transmission flows are a function of an ever-changing set of conditions that include but are not limited to generating unit availability and output, transmission configuration, and load levels. As such, the size of a particular electrical market is never static.

Generally, electrical markets separate and become smaller as the electrical system becomes more constrained. As markets grow smaller they become less competitive since the available universe of buyers and sellers shrink. During unconstrained periods there are many buyers and sellers. At the other extreme, when the system is very constrained, a relevant electrical market may consist of a single buyer or seller. In other words, the competitive playing field is often not level or balanced. The field typically becomes less balanced as the transmission system becomes more constrained. As such, the degree of separation in LMPs throughout PJM can provide insights with regard to the competitiveness of the electrical system for a given area.

While the degree of LMP price separation within PJM can provide insights as to the competitiveness of the segmented electrical markets, it should be noted that factors other than transmission constraints can contribute to the degree of price separation and that the degree of price separation is not an absolute indicator of competitiveness. The greatest difference in price between regions may not correspond with the time when the system is the most constrained due to other factors that may impact LMPs. For example, LMP price differences may be greater when the spread between fuel prices, i.e. between coal and gas prices, is higher even if dispatch and transmission flows are identical.

LMP prices can also be used as indicators of what competitive prices would be in the absence of regulation or price caps. The LMP market is in effect a spot market where the spot price of electricity is clearly defined. Once again, however, LMP prices should not be viewed as an absolute indicator of the market price of electricity. Competitive prices may also be derived through bilateral contracts or auctions. While not absolute, LMP is a good indicator of potential market prices since they may also form the basis for longer term pricing arrangements. Such arrangements will likely reflect expectations of LMPs over the terms of those arrangements as well as the risk premiums or discounts that may be required as a result of risk aversion.

Given the insights that can be obtained from LMPs, the Staff has collected LMP information and analyzed that information in a number of ways. The following table shows the simple average day-ahead LMPs for various Virginia utility zones and the entire PJM footprint for the twelve month period ending April 30, 2006:

AEP	$41.35 / MWh
APS	$59.97 / MWh
Delmarva Power	$67.97 / MWh
Dominion Power	$67.26 / MWh
PJM	$58.88 / MWh

As can be seen, the Delmarva and Dominion zones are the more expensive zones within Virginia. AEP is a less expensive zone. This simple comparison is consistent with other LMP comparisons, which consistently indicate that Dominion and Delmarva LMPs are typically among the highest in PJM.

The following table presents the load-weighted monthly average day-ahead LMPs for AEP, APS, Dominion Power, and the entire PJM footprint for the twelve months ending April, 30, 2006[26]. The load weighted LMP price is a better indicator of market prices in that the actual costs incurred to serve load will vary with the respective load and price for the varying time intervals. LMPs paid by loads vary hourly.

[26] PJM does not post the hourly loads for the Delmarva zone and the Staff could not calculate the load weighted LMP for that zone.

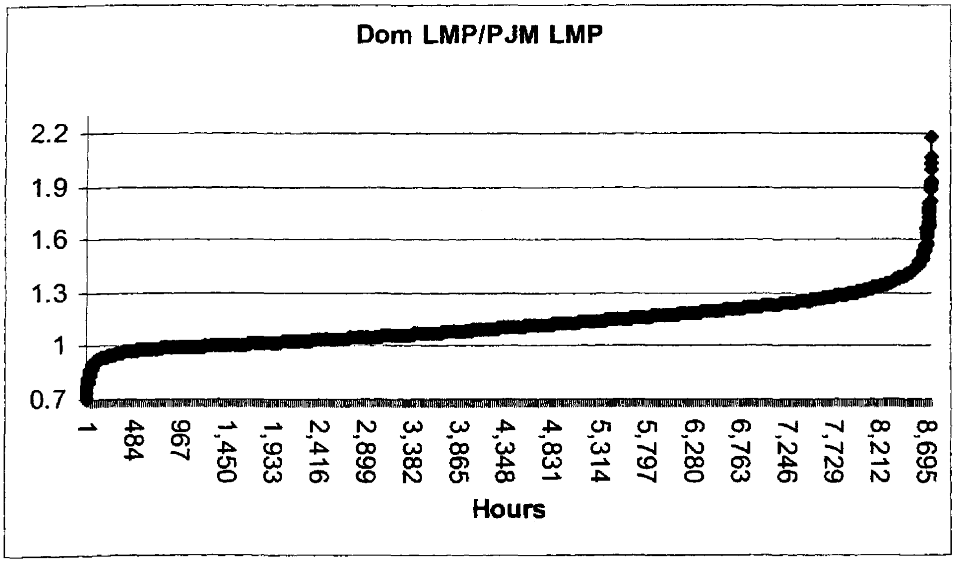
Average Monthly Load Weighted LMP

	AEP	APS	Dom	PJM
	/MWh	/MWh	/MWh	/MWh
May	$ 35.35	$ 40.75	$ 43.53	$ 40.87
Jun	$ 48.61	$ 55.88	$ 65.68	$ 59.16
Jul	$ 58.04	$ 69.89	$ 82.02	$ 71.78
Aug	$ 64.88	$ 81.56	$ 95.30	$ 82.97
Sep	$ 60.98	$ 78.51	$ 92.57	$ 79.73
Oct	$ 54.47	$ 70.42	$ 82.34	$ 71.89
Nov	$ 46.59	$ 59.68	$ 61.47	$ 57.61
Dec	$ 71.35	$ 90.70	$ 90.54	$ 83.89
Jan	$ 42.55	$ 50.14	$ 59.05	$ 51.94
Feb	$ 44.63	$ 52.45	$ 67.17	$ 54.57
Mar	$ 46.37	$ 55.99	$ 65.55	$ 55.24
Apr	$ 45.08	$ 49.58	$ 52.47	$ 48.62
12 Months	$ 52.10	$ 63.91	$ 73.01	$ 64.18

By way of comparison, anecdotal information indicates that the average total cost of AEP's and APS's generation is around $40 /MWh. These embedded costs are considerably below the weighted average LMPs for those zones. Additionally, those LMPs reflect only one component of generation costs required in conjunction with the PJM markets. It should be noted that the above figures do not reflect any offsets that may be associated with revenues received from transmission revenue rights that may have been received by load serving entities in the above zones. Revenue from such rights can be thought of as hedges against transmission congestion that may be contributing to higher LMPs. Such revenues would reduce the above figures. For example, the inclusion of these revenues for the Virginia portion of the Dominion zone would reduce the 12 month average LMP for the Dominion zone from $73.01 /MWh to $69.28 /MWH.

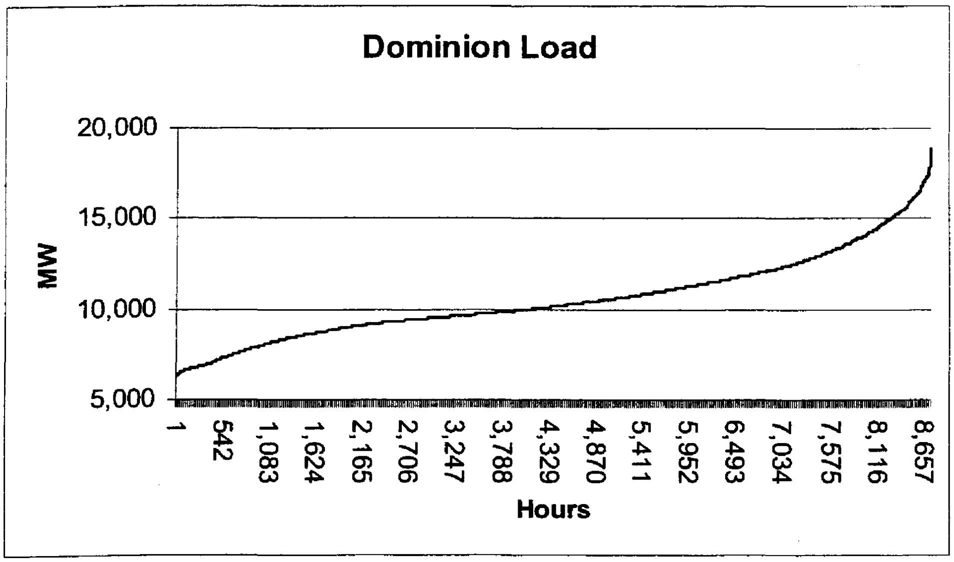
The Staff has also examined differences in hourly LMP prices for the Virginia Zones and PJM in attempt to gain insights as to the degree of market segmentation impacting competition in the Commonwealth. For the 12 month period ending April 30, 2006, prices were uniform throughout PJM during 58 hours, less than 1 percent of the time. In other words, PJM experienced transmission constraints to some degree or the other greater than 99 percent of the time. During these periods, prices will be higher or lower in the various zones depending on each zone's access to specific generating units. If a given zone has less access to low cost generation as a result of transmission congestion it will experienced higher LMPs. Conversely, zones that have lower cost generation that would otherwise be dispatched in the absence of transmission congestion would see lower LMPs when the system is congested. For example, the average hourly LMP for the AEP zone exceeded the PJM-wide LMP during 188 hours and was below the PJM-wide LMP during 8,513 hours during the twelve months ending April, 2006. On the other hand, LMPs in the Dominion zone were lower during only 1,304 hours and higher than the PJM-wide LMP during 7,396 hours for this same period. This indicates that the AEP zone generally has access to lower cost generation while the Dominion zone has far less access to cheaper generation.

The Staff has attempted to gain further insight as to the degree of market segmentation impacting the Dominion zone by dividing the hourly Dominion LMP by the corresponding PJM-wide LMP. While price difference is, as noted earlier, not an absolute indicator of the degree of market segmentation it does provide some limited insight. Dominion zone and PJM-wide prices are the same only where the blue line in the chart intersects the "1" line on the following graph. As the graph depicts, for thousands of hours the Dominion zonal price is higher, often much higher, than the PJM-wide price. Since a single entity (Dominion) owns or controls approximately 90 percent of the generation located within the Dominion zone, this appears to indicate that the Dominion Zone may be subject to uncompetitive conditions during many hours.



PJM's "2005 State of the Market Report" provides some further, albeit limited, insight into the degree of market segmentation within the Dominion zone. In the PJM report market concentration is expressed in terms of the HHI index. The PJM market monitor considers markets to be un-concentrated, moderately concentrated, and highly concentrated at HHIs below 1000, between 1000 and 1800, and above 1800 respectively. While the PJM report concludes that PJM's overall energy market was moderately concentrated in 2005, with HHIs varying from 855 to 1854, the report notes that the intermediate and peaking portions of supply are highly concentrated and the baseload portion is moderately concentrated. It is crucial to note that these concentration measures apply to the entire PJM footprint and that individual zones within PJM may have greater concentrations.

Given the highly concentrated nature of the intermediate and peaking portions of PJM's aggregate supply curve, the Staff developed the following load duration curve for the Dominion zone in an effort to further assess competitiveness of that zone.



The above curve is informative in that it can provide insights regarding the zone's reliance on intermediate and peaking units. There are approximately 9,600 of nuclear or coal fired capacity, i.e. baseload capacity, located within the Dominion zone. The load within the Dominion zone is less than or equal to the amount of baseload capacity during approximately 3,300 hours of the year. Conversely, the load exceeds the baseload capacity during approximately 5,460 hours or 62 percent of the time. During these hours, the Dominion zone's reliance on the highly concentrated portion of PJM's overall supply curve increases as total load increases. The concentrations associated with this supply segment become even greater as load grows and the PJM system becomes more constrained. Again, this would indicate that competitive conditions are less than optimal during a significant portion of the time.

Significant RTO-Related Dockets at FERC

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).

As reported in last year's report, the integration of Virginia's transmission-owning utilities into FERC-regulated RTOs is complete; nevertheless, the work of the Commission insofar as participation in FERC dockets continues. This segment of the report will furnish updates on dockets that were underway—and in which the Commission had intervened—as last year's report went to publication. Additionally, during this past year, the Commission has intervened in significant new FERC dockets that relate to the structure and operation of RTOs. These are discussed below, as well.

The Commission's Participation in New FERC Dockets:

Joint State/Federal Board examines economic dispatch.

Pursuant to the Energy Policy Act of 2005, FERC convened joint state/federal boards to study security constrained economic dispatch ("SCED") for various market regions of the country. The Commission nominated Howard M. Spinner, Director of its Division of Economics and Finance to serve a Virginia's official representative on the joint board studying SCED in the PJM/MISO region. All regional joint boards were convened in FERC Docket No. AD05-13-000 pursuant to initial order dated September 30, 2005.

Each joint board was authorized to:

- consider issues relevant to what constitutes "security constrained economic dispatch";
- consider how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned; and
- make recommendations to the Commission regarding such issues.

For purposes of this proceeding, FERC adopted the definition of economic dispatch provided in section 1234(b) of the Energy Policy Act of 2005 as the definition of security constrained economic dispatch, *i.e.*, "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."

The Joint Board for the PJM/MISO region submitted its final report to FERC on May 24, 2006. The report is available on the FERC website at http://elibrary.ferc.gov/idmws/search/results.asp. The final report's first section includes a summary of 17 recommendations. Key recommendations include:

- An ongoing demonstration of benefits from PJM and MISO managed SCED is important for sustaining market participant and state regulator confidence in the RTOs. The RTOs should establish a clear benchmark to assess the degree to which the reliability and least cost objectives of optimal SCED, as described in EPAct's SCED definition, are being captured.

- Because adequate transmission infrastructure is important for the achievement of SCED's least-cost and reliability objectives, the RTOs should devote adequate resources and substantial management attention to the transmission expansion planning process.

- The RTOs are encouraged to bring to the attention of state regulators any situations in which transmission facilities found to be needed in the RTO expansion plan are not getting implemented in a timely manner.

- RTO independence is critical for the RTOs' ongoing credibility. Accordingly, PJM and MISO are encouraged to continue to strive for independence as a bedrock principle. Both state and federal regulators have a role in the oversight of RTO independence.

- Some state regulators believe that they do not currently have sufficient access to the data needed to evaluate and oversee the RTOs' operation of market-based SCED. The RTOs' policies for limited state regulator access to data should be revisited.

FERC submitted its final report to Congress on Monday July 31, 2006. In that report, the FERC noted that "None of the joint boards recommends fundamental changes in the way security constrained economic dispatch is conducted in their respective regions" and that there were no recommendations for Congressional action.[27]

Electric Energy Market Competition Task Force.

The Energy Policy Act of 2005 established an inter-agency task force, known as the Electric Energy Market Competition Task Force ("Task Force"). This task force was charged with conducting a study and analysis of competition within the wholesale markets and retail markets for electric energy in the United States. The Task Force consisted of 5 members:

- one employee of the Department of Justice, appointed by the Attorney General of the United States.
- one employee of the Federal Energy Regulatory Commission, appointed by the Chairperson of that Commission.

[27] The full report can be viewed at: http://www.ferc.gov/industries/electric/indus-act/joint-boards/final-cong-rpt.pdf.

- one employee of the Federal Trade Commission, appointed by the Chairperson of that Commission .
- one employee of the Department of Energy, appointed by the Secretary of Energy, and
- one employee of the Rural Utilities Service, appointed by the Secretary of Agriculture.

In addition, as required by EPACT 2005, FERC opened a docket, No. AD05-17, by order of October 13, 2005. In that docket, FERC directed the Electric Energy Market Competition Task Force to study competition in wholesale and retail markets for electric energy in the United States. The Task Force is also charged with delivering a final report to Congress within one year of the effective date of the act. The purpose of this study was to analyze the critical elements for effective wholesale and retail competition, the status of each element, impediments to realizing each element, and suggestions for overcoming these impediments.

The Task Force was required to "consult with and solicit comments from any advisory entity of the task force, the States, representatives of the electric power industry, and the public." For both wholesale and retail competition for electric power, the Task Force was instructed to focus on the current state of competition and on factors that help support competition, or that otherwise may limit competition, among suppliers and buyers in regional wholesale markets and retail markets at the state level. In order to produce their report, the Task Force sought comments on a series of questions, some of which are set forth below:

- What are the critical elements or attributes of competition in wholesale electricity markets that the Task Force should examine?

- What are the critical elements or attributes of competition in retail electricity markets that the Task Force should examine?
- What benefits have occurred because of competition in wholesale and retail electricity markets? What additional benefits are expected? What benefits were forecasted and have not occurred? Why? What harms have occurred because of competition in wholesale and retail electricity markets?
- What are the major public policy concerns that the Task Force should examine in its review of competition in wholesale and retail electricity markets?
- In what significant ways do wholesale and retail electricity markets differ from other energy or commodity markets? What implications do their differences have for public policy?

The Virginia State Corporation Commission responded to the Task Force's request for comment on the state of competition for electric service by submitting the 2005 Report to the Commission on Electric Utility Restructuring of the Virginia General Assembly And the Governor of the Commonwealth of Virginia titled Status Report: The Development of a Competitive Retail Market for Electric Generation within the Commonwealth of Virginia.

On June 5, 2006, the Task Force produced a draft report. Comments have been received on the draft and a Final Report is to be delivered to Congress in August, 2006.

PJM Files its proposed Reliability Pricing Model.

On August 31, 2005, PJM filed under sections 205 and 206 of the Federal Power Act ("FPA") a proposal for a reliability pricing model ("RPM") to replace its currently existing capacity obligation rules. RPM is a proposal to fundamentally change the manner and dollar amount that generating units are compensated for making generating capacity available to participate in the PJM markets. PJM proposed RPM in a section 206 filing at FERC. This maneuver had PJM filing a complaint against its own existing capacity market construct, claiming that its existing capacity market did not produce outcomes that were just and reasonable.

PJM's RPM proposal addresses a key concern that competitive markets will not ensure adequate generating capacity at reasonable cost to consumers. Proposed RPM is, in part, an administrative mechanism that will set generator payments at the intersection of an auction-based supply curve and an administratively determined demand curve. The annual auctions would solicit capacity offers for a year four years into the future. The intersection of those points will occur at a point that yields an administratively determined level of capacity necessary to provide adequate reliability. This process is done separately for different sub-regions within PJM to take into account regional deliverability issues. The proposal also includes a reliability backstop feature that has PJM enter into long-term contracts for capacity if the capacity auction fails to produce a sufficient level of capacity necessary to meet PJM reliability requirements.

FERC docketed the matter as Nos. EL05-148 and ER05-1410. On April 20, 2006, FERC issued an "initial" order in this matter that found PJM's existing capacity construct is unjust and unreasonable. No evidentiary hearing had been conducted.

The April 20 order made certain rulings and provided guidance as to various issues raised with respect to establishing the just and reasonable replacement for PJM's existing capacity construct. The order also established further procedures, including a paper hearing and staff technical conference, for resolving the remaining issues. In the order the FERC encouraged the parties to continue to seek a negotiated resolution, and offered the FERC's settlement judge procedures or dispute resolution service ("DRS") to facilitate these discussions.

The Virginia State Corporation Commission's position can best be summarized by its June 1, 2006 comments in this matter. The commission stated that, like FERC, it is "well aware that there must be an adequate supply of generation for the near- and long-term future." The Commission expressed concern with PJM's proposed RPM since that, to date, there has been no showing that PJM's proposed capacity market redesign will, or can, provide additional generation at just and reasonable rates. The Commission advised FERC that RPM, as proposed, would increase the cost of generation to customers today and that proponents of RPM have not established that customers will receive more than an empty promise for their increased payments.

The Commission's position is that PJM has not established that a capacity construct based on proposed RPM will result in just and reasonable rates nor has PJM demonstrated that its proposal will resolve resource adequacy problems. In addition, the Commission's position is that PJM has not established that the proposed RPM will move its market closer towards transparency and competitiveness and that, in fact, RPM may make these goals more elusive. The Commission closed its June 1, 2006 comments by re-stating its position that FERC should reject PJM's RPM filing. This matter is currently in the FERC settlement process.

PJM files tariff changes regarding its market monitoring function.

On April 3, 2006, PJM filed under section 205 of the FPA to amend Attachment M of its tariff, which governs its market monitoring function. FERC opened Docket Nos. ER06-826-000 and ER06-826-001 to hear this matter. In an order dated July 14, 2006, FERC found that PJM's proposed changes generally conform with the general principles established by FERC's Policy on Market Monitoring ("Policy Statement"),[28] and that application of that policy to PJM is just and reasonable.

In its filing, PJM sought to revise the enforcement powers of its Market Monitoring Unit ("MMU") and to conform to FERC's Policy Statement. In supporting pleadings, PJM held that its proposals reflect the appropriate allocation of policing and enforcement authority between the market monitor and FERC. PJM proposed to eliminate the MMU's authority to issue demand letters or make requests that market participants "discontinue actions." PJM also held that its proposals authorized additional action by the MMU to respond to market design or market rule issues. These actions include filing tariff changes, reports or complaints with the approval of the PJM Board. PJM proposed that should PJM not agree with any MMU recommendation for market rule or market design changes, the MMU may make its views known to FERC staff and PJM members.

This docket saw heavy participation by state commissions, consumer advocates and transmission dependant utilities (municipals and cooperatives). Other stakeholders also intervened. A joint protest was filed by Old Dominion Electric Cooperative, the Borough of Chambersburg, Pennsylvania, Delaware Municipal Electric Corporations, Inc., and ElectriCities of North Carolina (Joint Protestors), and the City and Towns of Hagerstown, Thurmont and Williamsport, Maryland (Maryland Municipalities). Protests were also filed by the Joint Consumer Advocates (representing Pennsylvania, Maryland, Ohio, the District of Columbia, Illinois and Indiana), Mirant Energy Trading, LLC,

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28 Market Monitoring in Regional Transmission Organizations and Independent System Operators, Policy Statement on Market Monitoring Units, 111 FERC ¶ 61,267 (2005).

Mirant Chalk Point, LLC, Mirant Mid-Atlantic, LLC and Mirant Potomac River, LLC, (collectively, the Mirant Parties), the Organization of PJM States, Inc. ("OPSI"), the PJM Industrial Consumer Coalition ("PJM ICC"), the Public Service Commission of Maryland (Maryland Commission), jointly by the Public Utilities Commission of Ohio, the Virginia State Corporation Commission and the Delaware Public Service Commission (collectively, the Joint State Commissions) and by the Commonwealth of Pennsylvania (Pennsylvania Commission).

Motions to intervene were filed by the Public Utilities Commission of Ohio, the Maryland Commission, OPSI, Joint Protesters, American Municipal Power-Ohio, Inc., PJM ICC, Exelon Corporation, Blue Ridge Power Agency, North Carolina Electric Membership Corporation, Maryland Municipalities, Williams Power Company, Inc., NRG Companies (NRG Power Marketing Inc., Conemaugh Power LLC, Indian River Power LLC, Keystone Power LLC, NRG Energy Center Dover LLC, NRG Rockford LLC, NRG Rockford II LLC, and Vienna Power LLC), Dominion Resources Services, Inc., Constellation Energy Group Companies (Constellation Energy Commodities Group, Inc., Constellation Generation Group, LLC, Baltimore Gas & Electric Company, Constellation NewEnergy, Inc), PHI Companies (Potomac Electric Power Company, Delmarva Power & Light Company, Atlantic City Electric Company, and Conectiv Energy Supply, Inc.), North Carolina Utilities Commission, Illinois Commerce Commission, Virginia State Corporation Commission, Pennsylvania Public Utility Commission, and Delaware Public Service Commission. Motions to intervene out of time were filed by Coral Power LLC, American Electric Power Service Corporation, and PPL Companies (PPL Electric Utilities Corporation, PPL EnergyPlus, LLC, PPL Brunner

Island, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, PPL University Park, LLC, and Lower Mount Bethel Energy, LLC). On June 23, 2006, a joint response to OPSI's comments was filed by PHI Companies, PPL Companies, The Dayton Power and Light Company, The Williams Companies, Inc., and NRG Companies (hereinafter, the Pepco/PPL/NRG Parties).

The main issue for state commissions, including OPSI, as well as consumer representatives and transmission dependent utilities was the independence of PJM's market monitoring unit. Specifically, these parties --- including this Commission --- sought to use this docket to make important changes in the relationship between PJM management and the PJM MMU. The Virginia State Corporation Commission, along with these other numerous interveners, advocated greater structural separation between PJM management and the PJM MMU. Alternatives means to achieve this result were advanced by the parties. PJM did not propose any tariff revisions regarding the independence of the MMU and opposed any changes its current structure as it relates to market monitoring.

The Joint Protestors argued that the MMU must be independent of the PJM Board and management. They also contended that the MMU is only able to provide consistent and impartial evaluations of existing RTO rules and tariff provisions if the MMU is independent from the PJM Board, management and market participants. The Joint Consumer Advocates disputed the requirement that the MMU have permission from the PJM Board prior to making regulatory filings to address design flaws, structural problems, compliance, market power and to seek remedial measures or make recommendations. The Joint Consumer Advocates and OPSI argued that to maintain independence, the MMU must be able to bring its concerns directly to the FERC and the FERC staff, and must be able to file comments and testimony in proceedings without the prior approval of PJM management

OPSI protested this filing by offering a series of changes intended to provide the MMU with increased independence. OPSI's protest was supported by the Pennsylvania Commission and the Joint State Commissions. The Maryland Commission also endorsed greater independence for the MMU. To promote greater independence OPSI argued that the MMU's budget should be developed by the MMU subject to FERC approval. It also argued that the MMU staff should report exclusively to the Market Monitor. Further, OPSI contended that the Market Monitor should have substantial job security and should only be removed for "just cause." OPSI and the Maryland Commission requested that PJM's filing be modified to require the MMU to notify state commissions when the MMU identifies a market problem that may require state commission action. Similarly, the Maryland Commission would like a time frame established for the MMU to provide information to state commissions.

PJM and the Pepco/PPL/NRG Parties responded to these pleadings by contending that many protestors are seeking to greatly expand the role of the MMU beyond what is contemplated by PJM's tariff revisions or FERC's Policy Statement. PJM also argued that many protestors seek to bring about changes to PJM's internal structure that are outside the authority of the FERC.

FERC decided that Protestors who seek changes regarding the independence of the MMU and its reporting obligations are making recommendations that are not raised in this filing and are therefore beyond the scope of this proceeding. FERC stated that it saw "no reason to institute a section 206 proceeding to address matters that are more global than the issues properly before us." As such, absent reconsideration by FERC or any subsequent judicial intervention, the independence of the PJM market monitor from PJM management will not be enhanced as a result of this proceeding.

Updates on Dockets discussed in the 2005 Report

Transmission rate increase sought by AEP.

In last year's report, the Commission discussed FERC Docket ER05-751-000, in which the American Electric Power Company sought to substantially increase its FERC-regulated transmission rates.

The FERC entered an Order on December 7, 2005, approving a settlement stipulation, intended to resolve all of the issues set for hearing in that docket.[29] Specifically, the settlement agreement approved by the FERC authorizes a three-phase rate increase for AEP's East Zone. The approved settlement sets forth a stated unit rate of $1,081.06/MW-month for Firm Point-to-Point and Network Integration Transmission Service during Phase I (11/05 through 03/06); $1,621.40/MW-month during Phase II (04/06 through the commencement of Phase III); and $1,757.40/MW-month in Phase III. The third phase becomes effective on the later of August 1, 2006, or the first day of the month in which AEP's new Wyoming-Jackson's Ferry line becomes operational. The Phase III rate provides AEP an 11 percent return on equity with respect to this transmission line. Additionally, the approved settlement provides for the recovery (from ratepayers) of AEP's RTO start-up costs at the rate of approximately $2.3 million per year through May 2020.

[29] The SCC was an intervenor in this docket, but not a signatory to the settlement.

These FERC-approved transmission rate increases will be paid by transmission customers of AEP, including AEP's operating companies such as APCo, which provides service in western and southwestern Virginia. These operating companies, in turn, may seek to pass along these transmission rate increases to their retail customers.[30]

FERC looks at PJM's methods for mitigating market power in load pockets.

As noted in last year's report, in FERC Docket EL04-121-000, the FERC was reviewing PJM's then current methods for preventing generation owners from exercising "market power." Market power in this context means hiking up generation prices above reasonable levels for the output of 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 had raised in this investigation was 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 suggested that "scarcity pricing" may actually be needed in some instances to induce new generation construction. The SCC intervened in this proceeding.

[30] As also noted in last year's report, increased AEP transmission rates will, at a minimum, 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.

The FERC approved a stipulation of settlement reached in this docket by letter order dated January 27, 2006. In summary, the settlement modified PJM's tariffs concerning wholesale price capping of units in constrained areas. A significant provision of this FERC-approved settlement establishes within the PJM market, five "Scarcity Pricing Regions" that have the potential to develop limitations in imports due to constraints on Extra High Voltage ("EHV") transmission facilities. EHV transmission facilities are rated at 500 kV or higher.

According to the settlement stipulation, scarcity pricing would triggered within these regions when certain actions are taken by PJM operators to address emergencies, such as dispatching on-line generators into emergency output levels and dispatching off-line generators that have been designated to run only in emergencies. Other triggering conditions include emergency voltage reductions, emergency energy purchases, and manual load dump actions. Scarcity conditions will be terminated when demand and reserves can be fully satisfied with generation that is not designated Maximum Emergency. When an action triggers scarcity pricing, PJM will set the price on its entire system or in a Scarcity Pricing Region, as applicable, equal to the highest market-based offer price of all generating units operating under its direction to supply energy or reserves on a real-time dispatch basis. PJM will not cap offers from any generation in the region while scarcity pricing is in effect, although such generation will remain subject to PJM's overall cap of $1,000 per megawatt-hour.

Additional provisions of this FERC-approved settlement establish generally higher offer caps for frequently mitigated (or capped) generation units. The settlement further requires PJM and the PJM Market Monitoring Unit to review and evaluate the eligibility of generating units dispatched out of economic merit order for reliability to set locational marginal prices. Finally, an important provision of the settlement retains the "three pivotal supplier" market test for capping offer prices,[31] subject to certain modifications, including (i) the application of offer caps to generation suppliers rather than generating units, and (ii) the inclusion of price sensitive demand and virtual bids and offers in the day-ahead energy market. The SCC was not a party to this stipulation.

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. The Commission intervened in this docket.

Modification of PJM's rate design could ultimately result in a shifting of costs between PJM zones, or control areas. For example, a uniform, system-wide PJM rate

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[31] As discussed in the Initial Comments of the Commission [FERC] Trial Staff in Support of the Offer of Settlement in this docket dated December 6, 2005, "[T]he test suspends offer caps in any hour in which PJM has more than three jointly pivotal generator suppliers available for redispatch to relieve a transmission contraint. The FERC considers a supplier "pivotal " in a market if its capacity is required to meet peak market demand. Thus, PJM's test considers a market competitive, with no need to cap offer prices, when there are at least four generators available, each on a stand alone basis, to meet demand in a transmission-constrained area." Trial Staff Comments at 2.

could decrease costs to customers located in the AEP zone and increase costs to customers located in the Dominion zone. 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.

On July 13, 2006, FERC Administrative Law Judge ("ALJ") William Cowan, assigned to this docket issued an Initial Decision—an administrative determination on the merits of the case that awaits review and ultimate disposition by the members of the FERC. In sum, the ALJ's Initial Decision concluded that PJM's existing zonal "license plate" rate is unjust and unreasonable, and should be replaced with a "postage stamp" or regional rate design to be made effective April 1, 2006. The postage stamp rate design effectively allocates all of the revenue requirements throughout an RTO's footprint. Transmission customers then pay a fixed uniform charge for energy transmitted *within the region* regardless of distance. As indicated in the Initial Decision, advocates of the postage stamp approach (including the FERC's Trial Staff) contend that such a rate "reflects the widespread benefits provided by an integrated system like PJM's and allocates costs on a socialized basis to all beneficiaries." Initial Decision at 88. The ALJ's determinations, at this writing, await further action by the FERC. While the SCC has intervened in this docket, it has taken no position regarding proposed changes to PJM transmission rate design in this docket.

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

The Commission also discussed in last year's report appeals taken 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, by the Office of the Attorney General of Virginia and the Commission. At issue in this appeal is whether DVP will be authorized to recover from Virginia ratepayers after 2010 (when DVP's capped rates expire), 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. DVP has intervened in the appeal, filing a brief in support of the FERC's decision. The appeal is scheduled for oral argument before the Circuit Court on October 10, 2006.

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.

AEP and DVP, 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.

There are 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 developed and filed with the FERC a new Reliability Pricing Model proposal that, if approved, is expected to increase wholesale capacity prices. 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.

<u>Access to PJM Market Information</u>

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 that the SCC requires to monitor wholesale markets. Over the past year, the SCC and its staff sought to obtain data and information necessary to carry out the market monitoring that was envisioned by the General Assembly when the Act was first passed in 1999. To date, our staff's efforts to work with PJM have met with mixed results. While PJM has made efforts to meet with the Commission and staff regarding this issue and appears to have instituted internal procedures to better track data requests made by the SCC staff, there remains significant difficulty obtaining key data and information necessary to independently assess the functioning of the competitive wholesale markets administered by PJM. This difficulty leaves the Virginia State Corporation Commission unable to independently warrant that PJM's competitive wholesale electricity markets are effectively competitive. Our staff continues to work with PJM to attempt to obtain the data and information necessary to answer this important and complex question.

As noted in last year's report, 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 bidding behavior associated with certain plants or generating companies is hidden from public view. Over the past year our staff and other industry observers have noted questionable bidding patterns by certain generators. The inability to identify entities' and generating units' particular bids as well as the six-month lag in bid reporting make it very difficult for independent investigators to use this most readily available data to conclusively determine that PJM's markets are reasonably competitive. It should be noted that PJM's general procedure for the release of this crucial data has been approved by the FERC and any changes in reporting procedures must be approved by that federal agency as well.

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. Yet, it continues to be 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 three state commissions (Pennsylvania, Kentucky and Maryland) have taken the steps necessary to obtain information under this FERC sanctioned process. Several state commissions, including the SCC, have studied the implications of participating in this process and appear reluctant to sign the FERC protocol for obtaining such confidential information. Importantly, up until this point, our information and belief is that no data has been requested by or provided to the three states currently participating under the terms of the FERC approved protocol for the provision of confidential information. It should also be noted that the FERC has approved this protocol only as a supplement to, and not a replacement for, existing state judicial processes through which state regulators might gain access to such information. PJM has recognized this fact, yet its interpretation is that formal legal proceedings must be undertaken before it will comply with a state information request. This represents a marked departure from the regular, ongoing exchange of information, formal and informal, which most state regulatory agencies have enjoyed with their jurisdictional utilities over the years.

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 currently working with PJM on alternatives to the FERC approved protocol that may allow PJM to provide confidential information to this Commission subject applicable Virginia law, without resort to initiation of formal legal proceedings.

OTHER ACTIVITIES AND ISSUES

Default Service Investigation

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 the 2004, 2005, and 2006 proceedings (Case No. PUE-2004-00001, Case No. PUE-2005-00002, and Case No. PUE-2006-00001, 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, 2003 and 2004 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) Virginia jurisdictional return on common equity adjusted to a regulatory basis.

	2001	2002	2003	2004
Dominion Virginia Power	9.80%	23.31%	14.40%	15.52%
Appalachian Power	9.52%	12.79%	13.96%	6.53%
Potomac Edison	13.80%	15.12%	10.35%	14.09%
Delmarva	6.47%	1.96%	4.33%	7.02%
Kentucky Utilities	10.76%	14.19%	13.43%	10.34%[32]

[32] Staff did not review and adjust Kentucky Utilities reported Earnings Test results because the Company has no regulatory assets and the applicability of the Restructuring Act to Kentucky Utilities was suspended effective July 1, 2003.

Each of the above companies filed financial data for calendar year 2005 during the first half of 2006. Staff has not yet completed its review of the 2005 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.

	2005
Dominion Virginia Power	6.61%
Appalachian Power	5.04%
Potomac Edison	2.38%
Delmarva	11.07%
Kentucky Utilities	8.08%

Base Rate Case Activity

Appalachian Power Rate Applications

General Rate Case

On May 4, 2006, APCo filed an application for a general rate increase pursuant to Chapter 10 of Title 56 and § 56-582 of the Code, and the Commission's Rules Governing Rate Increase Applications and Annual Informational Filings. APCo requested an annual base revenue increase of $198.5 million to be effective June 3, 2006. Such proposed increase is based on a return on equity of 11.50%.

The Commission issued its Order for Notice and Hearing and Suspending Rates on May 30, 2006, which, among other things, assigned the application Case No. PUE-2006-00065, suspended the proposed rates through October 1, 2006, at which time they may go into effect on an interim basis subject to refund, assigned the case to a Hearing Examiner, prescribed notice, and established a procedural schedule. Such procedural schedule was subsequently modified by the Hearing Examiner. The original public hearing date of November 7, 2006 has been retained to receive testimony from public witnesses. The evidentiary haring will begin December 6, 2006 at the Commission's offices.

The Commission has received Notices of Participation from The Kroger Co., the Old Dominion Committee for Fair Utility Rates, the VML/VACo APCo Steering Committee, the Office of Attorney General's Division of Consumer Counsel, and Wal-Mart Stores East, LP. The Commission has also received public comments in opposition of the proposed increase.

Adjustment to Capped Rates for Environmental and Reliability Costs

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. This case is still pending before the Commission. The evidentiary hearing was held February 27 through March 1, 2006. Participants to the case filed briefs on April 11, 2006. The Hearing Examiner Report has not yet been issued.

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 Commission entered its Final Order which adopted the proposed stipulation on September 23, 2005.

Prince George Electric Cooperative

In April 2006, Prince George Electric Cooperative notified the Commission of its intent to file for a general rate increase to its base rates. The Cooperative expects to file its application on or before October 1, 2006.

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[33] 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.

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

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 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 assists the OAG by providing technical advice 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.

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".

2006 has proven to be a very positive year in rating trends for the U.S. utility sector. Standard & Poor's upgraded six companies and downgraded only three.[34] On the other hand, outlook changes went in the opposite direction with outlook revisions to

[34] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; April 21, 2006.

negative far outnumbering outlook revisions to positive. Ratings outlooks are an indicator of expected future rating trends. Stable ratings outlooks outnumber negative outlooks by 2 to 1, and only about 11% of outlooks are positive. Standard & Poor's remains skeptical of utilities' forays into nonregulated business pursuits outside of the companies' core competencies. Such activities include merchant generation and energy marketing and trading. Much of the industry continues to re-emphasize core competencies, where risks are certainly more familiar, but still daunting. These include major pending regulatory decisions, the need for substantial infrastructure expenditures, fuel cost recovery in a high-fuel-price environment, and still low, but gradually rising, interest rates.

This year, the ratings for Virginia's Old Dominion Electric Cooperative ("ODEC") and five investor-owned electric utilities remained unchanged. The current Senior Secured Debt Credit Ratings and Outlooks are listed below. Following the matrix is a brief discussion of the Standard & Poor'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	A-/Negative
Kentucky Utilities	A/Stable
ODEC	A/Stable
Potomac Edison	BBB-/Positive
Virginia Power	A-/Stable

Appalachian Power – The rating of BBB for Appalachian Power 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"). AEP has completed its transition to focus on its core utility operations rather than its former unregulated operations. AEP has improved its liquidity and balance sheet by refinancing billions in utility debt, extending the terms of bank credit facilities, and issuing significant amounts of common equity. 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. A large and complex environmental-compliance program looms as AEP's greatest credit-related issue. The company projects an environmental capital-expenditure program totaling $4.1 billion through 2010 to meet stricter air-quality standards.

Delmarva Power - The rating of A- for Delmarva Power ("DPL") has remained unchanged from the last report. S&P rates DPL 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 - The rating of A for Kentucky Utilities (KU) has remained unchanged from the last report. KU's rating is based partly on its direct parent, E.ON U.S. LLC (formerly, 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 its parent's implicit support to E.ON U.S. LLC and its affiliates and on a corporate strategy that maintains a primarily low-risk, utility-based business profile. 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 six 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 – The rating of BBB- for Potomac Edison has remained unchanged from the last report. S&P rates Potomac Edison based on the consolidated credit quality of its parent company, Allegheny Energy, Inc. Taken on its own, the credit profile for Potomac Edison is substantially stronger than that of its parent, Allegheny. The company's funds from operations ("FFO") interest coverage of over 5x, FFO to total debt of about 30%, and debt to total capital of about 52% are strong. On the downside, with recent legislative and regulatory hurdles faced by Baltimore Gas & Electric Co. in

Maryland, the potential for a rate shock in 2009 exposes the company to similar legislative and regulatory risks. The parent, Allegheny Energy, Inc., has heavy, albeit improving credit matrics, capped tariff rates, and exposure to coal and emission credits. The positive outlook reflects the expectation that Allegheny will continue to execute its plan to improve its operations and reduce interest expense.

Virginia Electric & Power – The rating of A- for Virginia Electric & Power ("Virginia Power") has remained unchanged from the last report. S&P rates Virginia Power based on the consolidated credit quality of its parent company, Dominion Resources, Inc. ("Dominion"). Reasons cited by S&P for the rating of A- for Virginia Power include Dominion's cash flow stability and a reasonably favorable regulatory environment. Countering these positives are Dominion's riskier exploration and production ("E&P") operations, growing portfolio of unregulated power generation, commodity price risk exposure, and weak financial profile. Despite Dominion's current weak financial measures, the stable outlook for Dominion reflects an expectation for improvement in 2007 and beyond.

Virginia Power has an average business risk profile relative to its integrated electric utility peers. Base rate price caps through 2010 provide cash flow stability, and more time to buy down its out of market, nonutility generator contracts. However, in exchange the company has agreed to freeze the fuel factor portion of rates, which is fixed through June, 2007. In 2004, fuel costs were frozen at what management believed to be prices at which fuel risk could be managed, but coal and gas prices since climbed to historically high levels. Subsidiary of Dominion, Consolidated Natural Gas Co., could only partially offset the utility's higher fuel costs in 2005 with its unhedged E&P

volumes. Recent lower-than-expected natural gas prices have mitigated fuel costs at Virginia Power and fuel related losses in 2006 will likely be lower than estimated.

Retail Access Pilot Programs

On September 10, 2003 the Commission approved three retail access pilot programs proposed by DVP, making approximately 500 MW of load and up to 65,000 customers available to Competitive Service Providers. 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[35] and one or more localities may aggregate residential and small commercial customers utilizing an opt-out[36] method for the purpose of soliciting bids from CSPs for electricity supply service; (ii) a Competitive Bid Supply Service Pilot,[37] 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 originally approved, DVP agreed to provide a 50 percent reduction in the wires charge to encourage CSP and customer participation. As a result of the failure of the pilots to attract CSP participation, DVP requested, and the Commission approved, numerous modifications to the pilots in an attempt to encourage participation. The most

[35] The opt-in method requires that a consumer affirmatively choose to participate.
[36] The opt-out method requires that a consumer affirmatively choose not to participate; absent such a decision the consumer will be included.
[37] 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.

significant revision was increasing the wires charge reduction to 100 percent. Despite the modifications, no CSPs have enrolled customers.

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.
- 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

SUMMARY OF NATURAL GAS RETAIL ACCESS PROGRAMS IN VIRGINIA

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 August 1, 2006, WGL's program had twelve CSPs serving 7,598 non-residential customers, and four active CSPs were serving 50,882 residential customers. Cumulatively, these accounts represent approximately 13.1 percent of the 447,508 natural gas customers in WGL's service territory. It is important to note, however, that WGL's unregulated affiliate, WGES, serves approximately 85 percent of the switched customers.

CGV's Retail Access Program

As of August 1, 2006, there were three CSPs providing service to 2,257 non-residential customers, and two CSPs were serving 6,837 residential customers. Cumulatively, these accounts represent approximately 4.0 percent of the 229,934 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.

PART III

RECOMMENDATIONS TO FACILITATE EFFECTIVE COMPETITION IN THE COMMONWEALTH

PART III

Recommendations to Facilitate Effective Competition in the Commonwealth

Part III of this report includes discussions of comments advanced by various stakeholders as means of facilitating effective competition in the Commonwealth along with the SCC's continued actions to implement the elements of the Restructuring Act as soon as practicable. Also included is the SCC's analysis of key industry events occurring since the issuance of last year's report.

To assist development of a comprehensive list of recommendations to foster effective competition, on April 7, 2006, the Staff sent a letter electronically to over 90 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 the following initial and reply comments, included as Appendix III-A to this Report:

- Comments of Mr. Urchie B. Ellis (Dated 05/01/06)
- Comments of Dominion Virginia Power (Dated 05/17/06)
- Comments of Constellation New Energy (Dated 05/22/06)
- Comments of VCFUR/ODCFUR (Dated 05/22/06)
- Comments of Dr. Irene E. Leech (Dated 05/23/06), on behalf of the Virginia Citizens Consumer Council.
- Comments of Old Dominion Electric Cooperative (Dated 05/25/06)
- VA, MD, & DE Association of Electric Cooperatives Reply Comments (Dated 06/12/06)
- VCFUR/ODCFUR Reply Comments (Dated 06/12/06)

In similar surveys conducted in 2005, 2004 and 2003, the SCC received six, 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 responses, we did receive input from 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. While respondents' recommendations do not provide new ideas as to ways to better facilitate retail competition in Virginia, some respondents have reiterated or called anew for a fundamental reconsideration of Virginia's overall approach to electric industry restructuring. Behind these second thoughts and calls for policy reassessment is the realization that while the expiration of price caps may facilitate electric service competition at retail, resulting prices paid by Virginia's families and businesses may be substantially higher than what would have prevailed in the absence of restructuring. A related question could probe potential changes in federal policy direction impacting wholesale electric markets that could reduce retail prices paid by consumers in restructured electric markets. In fact, much of the Commission's participation in policy debates over the past several years as well as this past year has been directed at attempting to influence electric industry policy at the federal level to allow for the best possible market outcomes for retail customers in this Commonwealth.

An example of a call for fundamental policy re-examination comes from the comments and reply comments of the Virginia, Maryland & Delaware Association of

Electric Cooperatives. In their reply comments dated June 12, 2006, the Association asks:

1. Without regard to whether Virginia should ever have made the choice to go down the path of deregulation of retail electric service, is it the right path now for Virginia's future?
2. If not, is it possible to return to cost of service regulation, and what challenges would we have to overcome to do so?
3. Are there other, more important objectives than economically efficient competition, such as transmission system development, that would be a better focus for industry stakeholder efforts?

The Commission and its staff have spent considerable effort on a variant of the first question. As alluded to above, that variant involves studying and advocating for potential federal policy changes relating to FERC regulated wholesale markets and RTOs believed to be in Virginia's best interests. The third question posed by the Association continues to receive much Commission and industry attention. Regarding electric industry restructuring, should the policy goal be competition for electric service for competition's sake or should the policy goal be the provision of safe, reliable service at the lowest possible cost to Virginia's consumers?

Our last report noted that most perspectives submitted for inclusion in the 2005 report indicated that a major milestone was reached in the spring of 2005 when DVP integrated its transmission and generation facilities into PJM. That action completed the transfer of operational control of transmission lines to an RTO for the investor-owned utilities as required by the Restructuring Act. It was also stated in the 2005 report that "... after only a few months of RTO operation, it is premature to determine if the anticipated benefits to customers will be realized." To follow up, we note that it is still premature to determine if anticipated benefits will ever materialize. What has materialized is a new proposed PJM capacity market along with other federal policy changes that may substantially alter anticipated cash flows from those that would otherwise prevail without these FERC determined market "enhancements." We also note that based on the difficulty of obtaining much of the data and information requested from PJM, this Commission remains unable to independently warrant that PJM's competitive wholesale electricity markets are effectively competitive. Our Staff continues to work with PJM to obtain the data and information necessary to answer this important and complex question.

Other major issues mentioned in the comments, both presently as well as over the past several years, include the now largely non-existent issue of wires charges and the degree to which the low capped rates of incumbent utilities providing default service at rates presumably below market prices inhibit or prevent the development of robust retail competition in the Commonwealth. These low capped rates of incumbent utilities currently thwart the development of effective retail competition in Virginia. However, overcoming this barrier could well have Virginians paying more for electricity with the ability to choose a supplier than they would pay in the absence of choice. For example, it may turn out that the 25% increase recently granted to Delmarva Power Company serving approximately 22,000 Virginia customers may lead to greater choice. Moreover, customer ability to choose to take service from a competitive service provider might even allow some customers to mitigate the recent rate hike to some degree. However, it seems generally clear from the many comments received during the Delmarva rate proceeding that customers would forgo the right to choose in order to obtain greater rate stability, even if that stability means taking electric service from a single provider.

In their comments this year, both DVP and Constellation note that relatively low capped rates do not allow for the development of retail competition. DVP states its comfort with Virginia's restructuring legislation, noting that the Commission on Electric Utility Restructuring will soon begin a two year review on the provision of default service after the scheduled expiration of price caps in 2011. Virginia Power further contends that restructuring in Virginia has and will continue to produce benefits for electricity consumers in the Commonwealth. DVP's and Constellation's overall message can be interpreted as one of "stay the course" on electric industry restructuring in Virginia. In contrast, responses representing consumer interests remain skeptical about the ability of industry restructuring to produce benefits for Virginia consumers. Mr. Ellis urges this Commission "to make a strong report calling on the General Assembly to cancel electric deregulation..." Dr. Leech, as well as large industrial customers representative Virginia/Old Dominion Committee for Fair Utility Rates, urges that the General Assembly undertake a comprehensive policy reassessment.

As they did last year, the large consumer group cites examples of competitive wholesale markets resulting in significantly higher retail prices in other jurisdictions. 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 well articulated, and they believe a better balance of risks and benefits among all stakeholders is needed, the VA/ODCFUR stop short of suggesting a stop or reversal to electric restructuring. Instead these large customer representatives urge comprehensive policy changes at the Virginia General Assembly to remedy what they claim to be fundamentally unfair provisions of the Virginia Electric Utility Restructuring Act. Dr. Leech and Mr. Ellis contend that deregulation is not working, will not work in the future, and urge 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 to materialize.

The above discussion illustrates what likely may be the only consensus feature of the current debate surrounding the appropriate policy direction for this industry in Virginia as well as the rest of the country: the only thing stakeholders could likely agree on is that the debate has become more polarized over the past year with vast differences among parties as to the appropriate policy path for this industry. That said, and since the Commission does not have any new policy recommendations to facilitate effective competition in the Commonwealth, the Commission will not offer policy advice to the General Assembly or Governor regarding broader policy issues raised by stakeholder comments and reply comments. In the next section we strive to deliver the facts and assess the current situation in Virginia as well as regionally. Of course, should the legislative or executive branch seek policy recommendations regarding the appropriate policy path for Virginia's electric utility industry from the Commission, we would provide such recommendations in a timely manner.

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 our 2004 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 two years since the issuance of the 2004 report, the SCC continues to perform its charge to provide regulatory certainty and put in place the necessary infrastructure to implement restructuring.

As noted in last year's report, 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. As we stated last year and repeat again here, while delay in PJM integration was thought by some stakeholders to be a major impediment to the spread of retail competition in the Commonwealth, after almost two years for APCo and 16 months for DVP, 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 2006 and are not expected to apply in 2007. 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, it remains true the PJM integrations are still relatively recent events and future wires charges expectations are just that; expectations that may turn out differently. The possibility of a return to wires charges in the first half of 2007 does indeed add some degree of risk 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 proved highly controversial and time consuming. By the time of our report last year, these changes had yet to be implemented. Market conditions that continue to have electricity market prices exceeding capped generation rates (including fuel costs) by a substantial amount render these changes moot; 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.

In our report last year we noted that the State Corporation Commission had been monitoring the transition to competitive electricity markets, both wholesale and retail, within and without Virginia. Last year's report discussed what were described as "some ominous new industry features and trends." Over the past year, those ominous industry features and trends continued. Below, we use this report to update the General Assembly and Governor on how those trends have progressed this past year and how industry restructuring in Virginia has been affected by those trends. Many of these trends are discussed in more detail in the body of this Report. The trends as stated in last year's report immediately follow. Updates and analysis are then set forth below for each identified feature or trend.

- Single Price Auction. 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.
- Historical Wholesale Prices. 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.
- Actual Impacts on Customers. Some Virginia electric utilities (Craig Botetourt Electric Cooperative, City of Danville Municipal, and 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.

- Industry Consolidation. 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.
- FERC Actions. 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.
- Market Monitoring. 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.

Single Price Auction

The single price auction is the energy market model employed by PJM. This market model attracted considerable controversy as wholesale market prices have increased over the past few years. The model's basic premise is that in order to send an accurate price signal about what and where generation, transmission or demand response is needed, all generators receive the price paid to the last, highest priced generator selected to operate during that time period at that location. There is currently much debate about the theoretical underpinnings of this market structure as well as how it operates in practice. What is clear is that, for better or worse, the single price auction requires that customers purchase <u>all</u> energy for the applicable time period at the energy cost of the <u>most</u> expensive unit selected to serve load for that time period. This means that if the last unit needed to serve load has a very high marginal cost due to high natural gas prices, market manipulation or some other reason, all generation --- including units with much lower short-run operating costs --- will receive that higher price. Customers paying that higher price will pay considerably more for electric energy during that time period than had they paid an amount equaling the sum of the costs of each generating unit --- some higher but some lower cost --- required to serve load during the period under consideration.

The overall, long-run impact of imposing this market structure on consumers depends on many complex, debatable and controversial factors including the price spread between various generating units, the inventory of generating units in a particular market at a particular time, the ability of customers, distribution utilities, suppliers and generators to react to price signals and the timing and strength of any such reaction. Also vital are fuel prices, the degree of market competition, market rules and the effectiveness of market power mitigation when generators could potentially impact market results.

One of the goals of this discussion is to provide relevant analysis of the substantial and highly contentious default price increases recently proposed and currently effective in Maryland and Delaware. Very importantly and unlike the situation in most of Virginia, restructuring in those states led to a legal and financial separation of generating units from the customers that formerly relied upon those generating units for electric service. This means that the distribution utility providing default service (the provider of last resort) must purchase full requirements service in PJM's wholesale electric market or from entities that trade power in that market. In effect, the market results in PJM's single price auction market greatly influence the cost that default service providers, narrowly defined, must incur to provide default service to retail customers. The prior sentence's "narrowly defined" qualification is to highlight that very often the default service providing utility resides in the same corporate family as a wholesale trading entity or generation entity that reaps the benefits of higher prices resulting from PJM's single price auction model. Finally, note that both the single price auction as well as any wholesale power sale to default service providers is under the exclusive jurisdiction of FERC.

As a result of the expiration of capped rates as required under Maryland and Delaware restructuring programs, default service providing utilities in these two states proposed historically large rate increases for retail default service. The factors described in the above paragraph --- legal separation of generation from load, transfer of jurisdiction to FERC, and business structures that have default service providers intending to compensate generation in the same corporate family at relatively high marginal cost for electricity produced by generating units paid for through time by the very same ratepayers now facing the large rate increases --- have made the proposed default service rate increases very controversial.

A debate currently rages as to the cause of these price increases. One side of the debate maintains that rates, frozen for several years as a result of state restructuring proceedings, necessarily must rise as they "thaw" in an era of much higher fuel costs. The other side of the debate condemns the move to a default pricing regime greatly influenced by the results of the single price auction as practiced in PJM as the cause of the proposed price increases. A more polarized restatement of the central issue in dispute is: "The proposed Maryland and Delaware price increases are appropriate and result from an artificially low starting point combined with higher fuel costs reflected in well functioning wholesale electric markets" versus "the proposed increases are inappropriate and result from industry restructuring gone awry." The short answer is that both sides of the debate are jointly correct and neither is exclusively correct.

The issue is important to Virginia. At some point this Commonwealth may face this question for the bulk of the state's electricity consumers. As explained below, for the 22,000 customers of Delmarva Power Company on Virginia's Eastern Shore this question is currently relevant. For DVP and APCo, at some point rate caps will expire and predictions of the impact of that expiration will likely be controversial. The actual impact will crucially depend on the legal and financial structural location of AEP and DVP generation that, supported by Virginia ratepayers, has served Virginia load for many years. In other words, the legal and financial relationship between customers and the generation that has historically served them and that those customers have supported in rates for years will be crucial.

In Maryland and Delaware defenders of the rate increase note that rates in Maryland, for example, had been frozen for quite some time and it is to be expected that a thawing of those rates should lead to large increases. It is implied that the frozen level of rates was somehow set artificially low and that, other things being equal, one should expect that electric rates should rise over time much like the general level of prices in the economy. Moreover, defenders of the rate increase maintain that the new rate level is the result of an effectively competitive PJM LMP market employing the single price auction structure and that the default service auctions --- where the default service providing distribution utility solicits offers from suppliers to supply all-requirements service for a year's time --- are also effectively competitive.

The Virginia SCC and its staff is --- to the extent procedurally allowed --- closely monitoring the debate surrounding the appropriateness of default service rates in Maryland, Delaware and other states. Any proposed percentage increase is an arithmetic function of the existing rate and the new, proposed rate. In Maryland, it is posited by defenders of the proposed increase that the existing frozen rates were set artificially low and the new proposed rates are appropriate. The adequacy and appropriateness of frozen rates through time is an empirical issue that can be studied. Likewise, the appropriateness of the new proposed rates depends on the structure and functioning of PJM's wholesale markets and the default suppliers' power procurement processes. These factors can be studied to inform claims that Maryland and Delaware percentage rate increases are or are not too high.

In Virginia, the Commission's Annual Information Filing reporting requirements allow for an empirical assessment of the adequacy and appropriateness of frozen rates as they change through time. Also, the new level of rates required to collect default service costs are dependent on both the structure and the functioning of the PJM single price auction energy market as well as the power procurement techniques of the default service provider. The Commission has and will continue to study, assess and participate in FERC, OPSI and PJM stakeholder processes that will in large part determine the level of rates required to fund default service when rate caps expire in Virginia under the Restructuring Act.

Finally, one could view the recent Delmarva Power Company-Virginia fuel factor proceeding before the SCC as an empirical test of the above discussed proposition. In that matter, the company proposed to collect from its 22,000 Virginia customers costs required to recover power costs set by a default service procurement process presumably based on PJM administered markets for energy, capacity and ancillary services. That rate level, if granted by the Commission, would have increased Delmarva's rates by 49.5% and could be considered to result from changing to a regime where prices are based on the single price auction as administered by PJM as well as other factors including the increase in fuel costs.

An alternative method of calculating an appropriate rate increase for Delmarva's Virginia customers in this circumstance arose from a settlement agreed to by the company and the Commission in the year 2000. The settlement allowed the company to divest generating units that had served its Virginia load. That settlement method calculates required revenues based on the average cost of electricity across a portfolio of generating sources that once served Delmarva-Virginia customers and is more akin to the way costs and rates were determined before industry restructuring. That method, while still sensitive to increases in fuel costs, does not directly or indirectly re-price all power consumed at the cost of the most expensive generating unit. This latter cost-based method produced a rate increase for Delmarva-Virginia customers of roughly 25%. The difference between the 49.5% requested rate increased based on the single price auction and secondary default service solicitation administered by Delmarva and the lower 25% increase that results from a calculation based on average costs could be considered at least the short-term impact of implementing a single price auction market structure. Thus, both fuel price increases as well as the implementation of a changing market structure would have significantly impacted Delmarva-Virginia's rates if the cost-based settlement method was not available. Even with the cost-based alternative, prices still increased by 25% indicating that increased fuel prices significantly impact rates throughout the region.

The key point of this somewhat lengthy discussion is that regardless of whether fuel prices or PJM's single price auction are driving rates higher, the ability of state policy makers to mitigate financially adverse impacts on consumers crucially depends on the corporate structural relationship between generation and consumers. Had generation legally resided in the same entity charged with providing default service to retail customers, Maryland and Delaware policymakers would have had more options to deal with the pressures serving to increase default rates --- whether those pressures come from increased fuel prices, the transfer of jurisdiction to FERC, or the implementation of the single price auction, with or without the inappropriate exercise of market power. On the Eastern Shore, even though customers and the generation historically serving them were separated six years ago, the settlement in that separation proceeding provided this Commission an option to employ to mitigate the impact of Delmarva's requested 49.5% rate hike. For the vast bulk of retail customers in Virginia, as long as AEP and DVP generation legally reside in the distribution utility, policymakers in Virginia still have those options should they be needed.

Historical Wholesale Prices.

Wholesale prices, as set forth in the body of this year's report continue their upward trend. PJM load-weighted energy prices increased 43.1% from full-year 2004 ($44.34 per MWh) to $63.46 per MWh for full-year 2005. Energy prices for the first six-months of 2006 appear about 5% higher than for the comparable period last year.

Last year we noted that "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." This statement is still true as has been demonstrated by sizable rate increases facing many customers as they transition from rate caps, are served by municipal utilities or cooperatives with expiring long-term contracts or otherwise must take service at prices influenced by the market.

Actual Impacts on Customers.

Virginia transmission dependent utilities – municipals and cooperatives – continue to deal with high wholesale prices. For example, as reported by the VA, MD, & DE Association of Electric Cooperatives in their reply comments, the Town of Front Royal reports a 76% increase in its wholesale power rates. Also, Craig-Botetourt Electric Cooperative's wholesale rates recently increased an average of 18%. We also note that the Eastalco aluminum smelter near Frederick, Maryland did indeed cease major operations. All but about 60 of its 600 workers have been let go. Local and state officials continue to work to try to find an electric power provision plan that would allow the plant to resume regular operations.

Industry Consolidation.

Last year's report anticipated that PUHCA repeal may allow further industry consolidation. The Energy Act of 2005 did indeed become law and PUHCA has been repealed.

Two big pending mergers in the PJM region have yet to close. The proposed deal between Constellation (parent of Baltimore Gas & Electric) and Florida Power & Light appears to have been slowed down by the turmoil in Maryland. The proposed merger of Exelon and Public Service Electric & Gas (New Jersey) has yet to receive final approval from the New Jersey Board of Public Utilities. Adjacent to the region, Cinergy (OH, IN, KY) and Duke Energy (NC, SC) did complete there merger earlier this year.

FERC Actions.

The Federal Energy Regulatory Commission continues to 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. During the past year, FERC relaxed market mitigation rules by allowing for higher prices during periods when demand and supply conditions suggest that "scarcity" price signals are appropriate. In addition, FERC continues to move towards a new capacity market construct for PJM. This process is now in settlement conference before a FERC settlement judge. As such, as of this writing, it is not clear how such a market will eventually function or what changes in cash flows will result from any outcome that may be reached.

The FERC apparently continues to believe that raising the generation sector's financial returns will lead to a more robust, competitive generation sector that will benefit consumers in the longer run. The logic may be that higher prices now will lead to lower prices later. This theory has been embraced by other supporters of restructuring as they urge policymakers to "stay the course" because, in the long run, restructuring will produce benefits for consumers. While restructuring may or may not produce long-run benefits that outweigh short-run costs for consumers, we note that this proposition too can be subject to rigorous, quantitative thinking if not analysis. The way to compare potential short-run costs with expected long-run benefits is through the use of present value analysis using appropriate risk adjusted discount rates.

From the consumers' perspective, if the potential short run-costs of restructuring are relatively large and certain while the expected benefits are small, far off in time and less certain, restructuring looks like a bad deal. If these conditions are reversed, then restructuring would look like a good deal for consumers. One thing is clear, however. Economic behavior indicates that consumers appear to have relatively high discount rates, meaning their tolerance for short-run costs is low even if those costs buy considerable and certain long-run benefits.

Market Monitoring.

The SCC continues to be troubled by both the enormity of the market monitoring task, the inability to get timely responses to data requests, the placement of the PJM

Market Monitoring Unit internal to PJM's organizational structure, and FERC's oversight of PJM market monitoring. We will continue to direct our staff to work with PJM, OPSI, PJM stakeholders and FERC to remedy this serious flaw in Virginia's participation in PJM. Based on PJM's current practices and policies, the SCC cannot represent to the General Assembly or Governor that PJM's wholesale market is transparent, competitive or in the public interest of Virginia ratepayers.

Based on activities observed during the past year since we issued our last report we reiterate here our closing paragraph from the 2005 report:

> 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 solely as a result of increasing electricity prices.

APPENDIX III-A

RESPONSES FROM STAKEHOLDERS

APPENDIX III-A
RESPONSES FROM STAKEHOLDERS
CONTENTS

COMMONWEALTH OF VIRGINIA

Howard M. Spinner
Director
Lawrence T. Oliver
Assistant Director, Finance
David R. Eichenlaub
Assistant Director, Economics

1300 E. Main St.
P.O. Box 1197
Richmond, VA 23218
Telephone: (804) 371-9050
Fax: (804) 371-9935
deichenlaub@scc.state.va.us

STATE CORPORATION COMMISSION
DIVISION OF ECONOMICS AND FINANCE

April 7, 2006

Dear Market Participant:

As directed by §56-596 B of the Virginia Electric Utility Restructuring Act, the State Corporation Commission is preparing its sixth annual report to the Commission on Electric Utility Restructuring ("CEUR") and the Governor, to be filed by September 1, 2006. 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.

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. Because of the current status of high market prices, recent auction results within neighboring states, some experience with PJM, and the continued lack of competitive activity in and around Virginia, consider the Commonwealth's statute and offer any thoughts or recommendations, whether positive or negative.

Please provide your comments to me by May 12, 2006. 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, 2006. 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

E-Mail Distribution List

CSPs

August, Kimberly	KimberlyAugust@wges.com
Brunson, Meg	meg@bollingerenergy.com
Burns, Mark	mburns@naturalgas-electric.com
Cusati, Tony	tcusati@commerceenergy.com
Disney, Jack	Jack.disney@cesource.com
Dosker, John	jdosker@stand-energy.com
Duggan, Martha	Martha.Duggan@constellation.com
Dutzman, Matthew	mdutzman@gasmark.com
Day, Brandi	bday@urslp.com
Francis, Frann	ffrancis@aoba-metro.org
Gewirtz, Jonathan	gewirtzj@econnergy.com
Hanks, Marc	Hanksma@selectenergy.com
Huddleston, Paul	huddleston@renenllc.com
Jablonski, Linda	lindaj@americanpowernet.com
Jaramillo, Gil	gjarami@novec.com
Jeffries, Gary	gjeffries@dom.com
King, Mitch	mitchking@oldmillpower.com
Kooper, Jay	jkooper@hess.com
Kozlowski, James S.	jkozurs@aol.com
Lund, Lynelle	llund@electric.com
Markle, Frank	marklef@ugicorp.com
Mason, Jack	Jack_Mason@energywindow.com
Middleton, Jeff	jm@jpcomgroup.com
Mussio, Alyssa	amussio@stand-energy.com
Pozza, Gordon	gpozza@mmenergy.com
Ringenback, Teresa	TRingen@wpsenergy.com
Rosenstein, Stephen	elecdereg@flash.net
Schlanert, Rebecca	Rschlanert@electric.com
Sekinger, Ronald	rsekinger@deltaenergyllc.com
Shaw, Laura	lshaw@wges.com
Simmons, Gregg	gsimmons@pepcoenergy.com
Sisson, Robert	robert.sisson@co.fairfax.va.us
Tackett, Sheri	stackett@deltaenergyllc.com
Walker, Teresa	twalker@tigernaturalgas.com
Ward, Mark	markward@hotmail.com
Warner, Jr., G. Harris	ghw@ghwplc.com
Wright, Joan	Joan_Wright@energywindow.com

Industry

Anderson, John	janderson@elcon.org
Axselle, Bill	baxselle@williamsmullen.com
Browder, Meade	mbrowder@oag.state.va.us

Brown, Scott	scott.brown@exeloncorp.com
Camp, Ward	WCamp@twacs.com
Dailey, Mike	mdailey@novec.com
Davenport, Ellen	edavenport@vaco.org
Delurey, Dan	dan.delurey@dramcoalition.org
Dick, Tom	TAD_govern@msn.com
Dunn, Jim	jim.dunn@grcc.com
Edwards, Michael	medwards@vml.org
Ellis, Urchie	UBEllis@worldnet.att.net
Gary, Richard	rgary@hunton.com
Goodman, Craig	cgoodman@energymarketers.com
Greene, Brian	bgreene@briangreenelaw.com
Greenhalgh, Jack	jack@neweraenergy.com
Hathaway, Alden	ahathaway@ert.net
Hurwitz, Ken	ken.hurwitz@haynesboone.com
King, Chris	chris.king@americanenergyinstitutes.org
Leech, Irene	ileech@vt.edu
Lowenthal, Peter	plowenth@seia.org
Minneman, Jim	jmminneman@pplweb.com
Monacell, Louis	lmonacell@cblaw.com
Myers, Steven	steve@vplc.org
Nicholson, Tom	tnicholson@macbur.com
Perrin, Preston	pperrin@retailmerchants.com
Petersen, Alan	apetersen@ingenco.com
Peterson, Laurie	vrma@virginiaretail.org
Petrini, Ed	epetrini@cblaw.com
Roussy, Matt	droussy@oag.state.va.us
Sewell, Ron	rsewell@viterrausa.com
Sinclair, Steve	Steve.sinclair@co.fairfax.va.us
Sobin, Rodney	rsobin@deq.virginia.gov
Thompson. Thomas	Thomas.thompson@dmme.virginia.gov
Wallmeyer, August	augie@wallmeyercommunications.com
Warren, John	john.warren@dmme.virginia.gov
Dailey, Mike	mdailey@novec.com

LDCs - Electric Cooperatives

Bowman, John	jbow@meckelec.org
Bradshaw, Dale	dbradshaw@pgec.coop
Brinkley, Vernon	vbrinkley@anec.com
Farmer, Kent	kfarmer@rappelec.com
Feuerberg, Stanley	sfeuerb@novec.com
Groseclose, Gerald	craigbot@direcway.com
King, Bruce	co-op@barcelectric.com
Layton, Salud	slayton@odec.com
Longshore, Larry	executive@sec.coop

Pirko, John	jpirko@leclairryan.com
Puryear, Erin	EPuryear@odec.com
Reynolds, James	jreynolds@comelec.coop
Rubin, Susan	srubin@odec.com
Scarboro, Howard	hscarboro@forcvec.com
White, Greg	gwhite@nnec.com
Wine, Douglas	cdwine@svec.coop

LDCs - Electric

Bell, Karen	Karen_Bell@dom.com
Bush, Howard	Howard.Bush@lgeenergy.com
Cohen, Gary	gary.cohen@conectiv.com
Gambardella, Tony	agambard@woodsrogers.com
Golden, Phillip	goldep@pjm.com
Koogler, David	david_koogler@dom.com
Kruft, Chuck	ckruft@alleghenyenergy.com
Thomas, Barry	blthomas@aep.com

Dominion Virginia Power

E. Paul Hilton
Senior Vice President

Dominion Virginia Power
120 Tredegar Street, Richmond, VA 23219

Mailing Address: P.O. Box 26532
Richmond, VA 23261

May 17, 2006

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

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 develop your annual report.

As we have stated in past years, Dominion believes the Virginia restructuring program has produced significant benefits for consumers and promoted efficiency in the electric industry. The Commonwealth's restructuring effort has shown it can successfully adapt to changing circumstances. This flexibility, based on close regulatory and legislative oversight, has helped Virginia avoid the problems that have occurred in some other states undertaking restructuring. Virginia's program has laid a strong foundation for retail competition. Interest in customer choice remains high among competitive suppliers and aggregators, and the restructuring movement took a major step forward this spring when the Commission licensed the City of Fairfax as Virginia's first municipal aggregator. A higher level of retail competition should not be expected to develop until market conditions improve (i.e., wholesale market prices fall below capped rates). This would provide competitive suppliers with increased opportunity to make favorable offers. This situation could occur at some time during the period from July 1, 2007 through December 31, 2010. During this period Dominion's capped rates will be adjusted annually to reflect actual fuel costs.

Restructuring Already Producing Significant Consumer Benefits

While the restructuring process has not been perfect in Virginia, it has produced significant benefits for the Commonwealth's consumers. This is due in large measure to the close regulatory and legislative oversight built into the process. This oversight mechanism, apparently lacking in some other restructured states, has allowed Virginia to make necessary midcourse corrections to protect customers and keep the process on track.

The freeze imposed on Dominion's fuel factor by the 2004 General Assembly has produced hundreds of millions of dollars in savings for the Company's customers. The freeze, extending through mid-2007, was implemented just as fuel prices began surging toward record levels. The Company recently estimated the freeze will produce savings of about $260 for the typical residential customer using 1,000 kWh per month during the two year period of 2005-2006.

The General Assembly in April took additional steps to ensure the accuracy of the reset of Dominion's fuel factor beginning in 2007 and protect customers from a dramatic price increase. The legislature approved Gov. Tim Kaine's amendment requiring that Dominion's fuel factor be adjusted annually from July 1, 2007 through July 1, 2010. The amendment eliminated the need for a long-term, 42-month projection of fuel expenses through the end of 2010. This would have presented the Commission with an extremely difficult, if not impossible, job. The amendment ensures that Dominion customers will pay no more for fuel than Dominion's actual costs and provides annual opportunities for correction. The amendment also allows the Commission to defer up to 40 percent of Dominion's 2007 fuel factor adjustment to subsequent years, blunting its impact on consumers and offering further price stability.

As we have noted in past comments, the capped rate provisions of the Virginia Electric Utility Restructuring Act have also produced substantial savings for customers. The 2004 Dominion-commissioned study by Chmura Economics & Analytics projected that capped base rates will save residential consumers served by the Company as much as $1.8 billion through 2010. Residential customers will see annual savings of up to $74 during the Restructuring Act's transition period due to capped rates, according to the study.

Restructuring savings are not confined to Virginia. An October 2005 report by Cambridge Energy Research Associates found restructuring, through 2003, had produced $34 billion in consumer savings nationwide. Another consultant, Global Energy Decisions, reported last year that customers enjoyed $15.1 billion in benefits through increased wholesale competition from 1999 through 2003. Both the Public Utility Commission of Texas and the New York Public Service Commission have found restructuring has generated significant savings for consumers in their states. In New York, the PSC estimated inflation-adjusted power prices for utilities' residential customers dropped an average of 16 percent between 1996 and 2004.

Rates Increasing in Non-Restructured States

Controversy over increases in states such as Maryland and Delaware with expiring rate caps has tended to obscure steady, and in some cases dramatic, rate increases in many non-restructured states. For example, Wisconsin Public Service rates for customers in the eastern part of the state have risen approximately 60 percent since 2001. If the company's latest petition is approved, the rate of increase would rise to approximately 81 percent. Florida Power and Light's monthly residential bill for 1,000 kWh has risen from $69.73 in 2000 to $108.61 this year, an increase of approximately 56 percent, largely resulting from increasing fuel expenses. Residential customers of Public Service Company of Oklahoma, an AEP affiliate, experienced a 32 percent increase in December 2005 due to higher fuel prices.

As these examples indicate, escalating fuel costs have been the primary reason for the higher electric rates many consumers have experienced in recent years in states maintaining traditional cost-of-service regulation, as well as in restructured states. In addition, higher costs for equipment, materials (such as steel, copper and aluminum), labor and other factors in the production and delivery of electricity are exerting significant upward pressure on base electric rates.

Virginia Restructuring: Default Service

Virginia consumers can take comfort in the Commonwealth's careful steps to prepare for the expiration of capped rates and the beginning of market-based default service on January 1, 2011. As the Staff noted in their April 28 default service report, the Commission on Electric Utility Restructuring will soon begin a two-year review of the provision of default electric supply service after the capped rates expire. The study will allow Virginia to evaluate the experiences of other states and develop workable plans for the future. The CEUR review will also furnish this Commission with much of the information it will need to implement post-rate-cap default service.

Virginia Restructuring: Retail Competition

Interest by competitive power suppliers (CSPs) and aggregators in Virginia's restructuring program remains strong. As of May 4, six competitive suppliers and six commercial aggregators were licensed by the SCC. Of these, all except one aggregator were registered with Dominion. Market conditions, however, have made it virtually impossible for CSPs and aggregators to make customer offers more favorable than capped rate service. Wholesale market prices for electricity have risen sharply in recent years, in large part due to the rapid increase in fuel prices. The freeze imposed on Dominion's fuel factor by action of the 2004 General Assembly has protected consumers from rising fuel costs. However, this has made it even harder for CSPs to make attractive offers. We expect retail competition to begin developing in the Commonwealth as market conditions improve and the Dominon fuel factor is adjusted to recover increased fuel costs later in the decade.

We also continue to believe that aggregation provides the most effective means for bringing the benefits of retail competition to smaller customers, including residential customers and small businesses. One of the best ways to form customer buying groups is through municipal aggregation, with the city or county government acting as the buying agent for customers within the locality's boundaries. Municipal aggregation allows the locality's residents to achieve the critical mass needed to attract competitive providers. This method of procurement has had some notable successes elsewhere, including northeastern Ohio and the Cape Cod area of Massachusetts.

Municipal aggregation took a significant step forward this spring with the SCC's April 18 issuance of an aggregation license for the City of Fairfax. The license allows the city government to provide competitive aggregation service to residential, commercial and industrial customers within the city limits. Fairfax became the first locality in the state to apply for an aggregation license on February 21. This application followed Fairfax City Council's October 11, 2005 vote to create a municipal aggregation program with opt-out participation. (Customers will automatically be included in the aggregation unless they notify the city that they do not wish to participate.) With its license, Fairfax is now ready to enter the electricity market when conditions improve.

Dominion will continue to support Fairfax's efforts to conduct a successful aggregation program. Additionally, we will continue to assist other municipalities as they explore aggregation programs.

Retail Competition: Trends Elsewhere

Low shopping rates among smaller customers, coupled with continued rate caps and freezes, have tended to obscure the fact that fairly vigorous retail competition is developing in some states. This is especially true among larger users, such as industries and large commercial establishments. Data from several states emphasize this fact.

The New York Public Service Commission recently reported that competitive suppliers served 72 percent of the large commercial and industrial-class load in February; almost 55 percent of the accounts in the rate class were buying from competitive providers. Competition was also strong among small and medium-sized commercial customers, according to the Public Service Commission. Competitive providers furnished more than 44 percent of the rate class's load; almost 19 percent of the accounts within the rate class were shopping.

In Massachusetts, the Department of Telecommunications and Energy reported that competitive marketers in February were serving more than 56 percent of the state's large commercial and industrial users and 17 percent of its medium-sized commercial and industrial customers.

The attention centered on the pending standard offer service increases for residential customers in Maryland has also largely hidden the growth of electric competition in the state. Earlier this month the Maryland Public Service Commission said competitive providers served more than 80 percent of the large commercial and industrial accounts during March. Marketers also provided electricity to more than 15 percent of medium-sized commercial and industrial accounts. And in Maine, Public Utilities Commission shopping statistics indicate marketers served 38 percent of the state's total demand for electricity as of April 1. The Public Utilities Commission reported that competitive providers were serving 91 percent of the large industrial load in Maine Public Service's territory and 87 percent of the large industrial load in Central Maine Power's territory.

Consumer interest in retail competition also remains strong. A recent survey of registered voters in Connecticut found 87 percent want the ability to shop for power. Sixty-eight percent said competition was the best way to lower prices for energy, according to the survey sponsored by the Retail Electric Supply Association.

Virginia's Restructuring Effort: A Sound Plan for the Future

Virginia's restructuring effort has produced real savings for consumers and introduced greater efficiency in the electric utility industry. The initiative has shifted the risk for billions of dollars in new costs and investments from utility customers to the companies themselves and their shareholders. The Commonwealth's program has greatly benefited from the ongoing regulatory and legislative oversight prescribed by the Restructuring Act. Virginia's ability to monitor and correct its restructuring program sets it apart from the initiatives underway in several other restructured states. The oversight has allowed Virginia to deal with changing circumstances and make the midcourse corrections needed to keep the restructuring program on track. The examination of the post-rate-cap situation by the Commission on Electric Utility Restructuring is another example of this close oversight. The study should greatly assist all parties in developing the terms for the default service that will be offered after the capped rates expire.

Although market forces have worked against retail competition in Virginia in recent years, the Commonwealth's restructuring program has laid a solid foundation for customer choice. Interest by suppliers and aggregators remains high. The SCC's recent approval of a municipal aggregation license for the city of Fairfax marks a first step toward cities and counties acting as buying agents for their citizens. Additionally, significant numbers of customers are shopping for power in other restructured states, including Maryland, following the expiration of rate caps. Electric customers in Virginia are well positioned to realize continued benefits from capped rates during the rest of the transition period and to take advantage of the competitive market for electricity after the capped rates expire.

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

Sincerely,

E. Paul Hilton

Old Dominion Electric Cooperative

May 25, 2006

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

Dear Mr. Eichenlaub:

This is in response to your letter dated April 7, 2006, soliciting informal written comments regarding Staff's review of methods to facilitate effective competition in Virginia. This is the first year Old Dominion Electric Cooperative ("Old Dominion") has offered comments for your annual report. Now that the entire Commonwealth is within the PJM footprint, we believe our experience in that wholesale arena could be helpful to you, especially with regard to the status of regional competitive markets. Old Dominion appreciates the opportunity to provide input, and looks forward to participating actively in any further discussions with Commission staff and with the Commission on Electric Utility Restructuring (CEUR).

Old Dominion is a not-for-profit power supply electric cooperative, organized and operating under the laws of Virginia and subject to the Federal Energy Regulatory Commission jurisdiction. Old Dominion supplies capacity and energy to its twelve electric distribution cooperative members, ten of which are regulated by the Virginia State Corporation Commission. Old Dominion is a network transmission customer of PJM, as well as a PJM Transmission Owner. As a generation-owning utility, Old Dominion is dependent upon use of the transmission facilities of PJM under its Open Access Transmission Tariff ("OATT") to deliver the output of Old Dominion's generation facilities located within PJM and to deliver periodic power purchases from third party sellers to the load of its member systems in PJM's footprint. Old Dominion has been an active participant in PJM's stakeholder process since 1997.

The April 7 letter encourages the submission of comments regarding "national, regional, or Virginia restructuring efforts, policies, activities, or events." Specifically, the Commission is interested in ideas to facilitate effective retail competition in Virginia. As will be discussed below, Old Dominion is of the opinion that a viable and competitive wholesale market is a necessary prerequisite to retail choice and that more must be done to achieve such a wholesale market. Pursuant to §56-596 B of the Virginia Electric Utility Restructuring Act, Old Dominion offers these comments so that the Commission can make its report to the CEUR and the Governor to include recommendations that are in the public interest.

1. Status of Development of Regional Competitive Markets

Old Dominion has relied upon three general forums to shape its thinking on this topic: individual industry assessments, proceedings before the Federal Energy Regulatory Commission (FERC) regarding PJM, and the comments of others relative to retail choice. The industry assessments and retail comments speak for themselves. The PJM FERC proceedings have given us first hand experience in the current debates on market efficacy within an RTO that has been generally accepted through the industry as having the most viable competitive wholesale market.

A. The Industry Assessment of Competitive Markets

A number of competing studies have been widely circulated that, depending on who commissioned them, attempt to either portray competitive markets as a resounding success or refute the pro-competitive studies by pointing out significant omissions or errors in approach. A summary of some of the more prominent studies and their counterpoints is presented below.

Although the study results differ, there is still tremendous value that can be derived from these conflicting views. First, it is useful to consider the many different metrics that can be used to assess performance and the drawbacks of each. Second, it is instructive to understand the positions of the study sponsors as one reviews a particular study's conclusions. Consistently, studies declaring victory are sponsored by independent generation and investor-owned utility groups while the counter studies are commissioned by load interests. It is of particular note that all studies purport to represent the view of consumers!

Most importantly, however, these competing studies remind us that we must do our own due diligence and seek to objectively assess success or failure. They point out the danger of relying on sound bites prepared by special interest groups that support pre-determined perspectives on an issue. Recent retail rate issues in Maryland and Delaware are also instructive as we evaluate success. As Dr. Roy Shanker pointed out in Richmond during PJM's April 26, 2006, meeting, economists are seeking economic efficiency and not lower prices. We must bear this caution in mind as the Virginia General Assembly assesses the next move to facilitate competitive markets in the Commonwealth.

These studies are also useful in that they affirm that, at this point, it is too soon to tell if competitive wholesale markets have been successful or not. The infrastructure of our current electric grid evolved from the PUCHA rules established in the 1930's. The current transmission grid was built by vertically integrated monopolists in a regulated cost-of-service environment where generation and transmission planning was harmonized and coordinated for the least cost result. Unbundling generation and transmission under FERC Orders 888 and 2000 represented a significant change in approach. Generation and transmission construction are no longer coordinated, and market participants are still working to develop wholesale market and planning rules to accommodate this huge paradigm shift. In PJM, the industry has been "experiencing" a uniform clearing price LMP market since 1998. The electric utility industry is still evolving and many additional changes will be required to achieve the anticipated benefits of a truly competitive wholesale market.

For all but the Cambridge Energy Research Associates ("CERA") "Crossroads" study[1], Old Dominion has attached the actual reports for those who wish to explore these in more detail. Study summaries follow[2]:

Studies

(i) CAEM Study -- Dr. Ron Sutherland, from the Center for the Advancement of Energy Markets ("CAEM"), prepared a study entitled "Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region" in 2003. The study found that the present discounted value of future savings to consumers in the PJM region as a result of then current restructuring efforts would be about $28.7 billion. The study broke down the savings into two components. The first $20.1 billion was derived using a comparison of retail electricity price changes in PJM between 1997 and 2002 to retail price changes in neighboring states and the United States average. The second $8.6 billion was attributed as a "post stranded cost recovery" benefit representing the savings that customers would enjoy when the stranded cost recovery period ends resulting in a decline in PJM prices in the year 2009. (See Attachment 1.)

(ii) Kirsch, Morey Response to CAEM Study -- On the other hand, in a report entitled "Erecting Sandcastles from Numbers: The CAEM Study of Restructuring Electricity Markets Or a Critique of Estimating the Benefits of Restructuring Electricity Market: An Application to the PJM Region," by Mathew Morey, Laurence D. Kirsch, Steven Braithwait, and Kelly Eakin, all of whom are associated with Laurits R. Christensen and Associates, the authors refute the CAEM report stating that the study represents a seriously flawed analysis of the economic effects of restructuring in the wholesale and retail electricity markets in the PJM region. Morey *et al* add that the CERA study cannot be relied on to identify the elements of restructuring in the wholesale and retail markets or to infer what, if anything, is good or bad. The study fails to conduct a proper benefit-cost analysis of restructuring, and has not provided any evidence that the reductions in retail prices in the PJM states from 1997 to 2002 were the effect of any efficiency gains resulting from restructuring either the wholesale or retail markets. They conclude their analysis by stating that while restructuring wholesale electricity markets may provide long-term benefits (and have achieved a certain level of success in some parts of the country), there are some key restructuring problems which have not been solved, partly because "policymakers underestimated the nature and magnitude of the technical and institutional challenges associated with successfully introducing competitive markets." (Christensen report, p. 21) (See Attachment 2.)

(iii) Cambridge Energy Research Associates ("CERA") Study -- The CERA study, entitled "Beyond the Crossroads: The Future Direction of Power Industry Restructuring," (2005) estimates that the average U.S. residential electric consumer paid about $34 billion less for electricity over the past seven years than they would have paid if traditional regulation had continued. They claim that the savings from deregulation reflect many of the expected gains from introducing more competitive pressures into the power business, introducing greater efficiency, more innovation, and cost discipline. The report also concludes that under a deregulated regime, the costs of new supply are shifted to investors who hold the market risk as opposed to going into ratebase, implying that deregulation reallocated the risk in the power industry.

(iv) Kirsch and Morey Response to the CERA Study -- Kirsch and Morey refute the CERA study in a report entitled, "Beyond Belief: A Critique of the Cambridge Energy research Associates' Special Report – 'Beyond the Crossroads: The Future Direction of Power Industry Restructuring.'" (See Attachment 3.) Kirsch and Morey argue that CERA's net benefit findings rely on

[1] The CERA study resulted from a solicitation by CERA among competitive market advocates and is available only to non-participants for a fee.
[2] The bibliography for each of the studies referenced here is included in Appendix A.

the assumptions that (1) markets in all four regions were "regulated" through 1997 and were "deregulated" after 1997, and (2) that CERA's statistical model provides reasonable estimates of what retail electricity prices would have been if deregulation had not occurred. These assumptions are erroneous and render the study "beyond belief" for the following reasons:

- The study is careless in its distinction between regulated and deregulated market periods;
- There is an ascription of the lion's share of deregulation benefits to the southern region to the tune of $24 billion dollars although this region has experienced little deregulation;
- There is a large share of the benefits attributed to the Midwest region even though that region had no functioning RTO until 2002;
- The study counted losses of generators during the recent "bust" portion of the business cycle as part of the deregulation benefits for residential consumers and these losses are not sustainable over the course of the business cycle;
- The study ignored the huge administrative costs of implementing restructuring which would offset any efficiencies that might be passed on to residential consumers;
- The empirical analysis focused solely on retail electricity prices when the direct effects of deregulation are primarily on wholesale prices, and additionally the continuing regulation at the state level of rates prevents a direct link between retail and wholesale prices; and
- The prediction equation miscalculates what "regulated" prices would have been after 1997.

(v) Global Energy Decision Study -- Global Energy Decision ("GED") prepared a study entitled "Putting Competitive Power Markets to the Test," Sacramento, July 2005, which concluded that over the 1999-2003 period, consumers in the "Eastern Interconnection have realized a $15.1 billion benefit due to wholesale competition over what they would have realized under the traditional regulated utility environment." (Report, p. 1-1) They also have determined that the industry as a whole has improved its operations and efficiencies largely due to competitive forces. (See Attachment 4.)

(vi) Kirsch and Morey Response to the GED Study[3] -- The GED report was reviewed and critiqued by Kirsch and Morey in their report titled "Putting Competitive Power Markets to the Test: An Alternative View of the Evidence." (See Attachment 5.) Kirsch and Morey conclude that the GED results are based on false assumptions that lead to grossly overestimated benefits. Their arguments against the report's assumptions are as follows:

- GED wrongly assumed that losses sustained by competitive suppliers during the 1999-2003 study period, which account for over half of the estimated benefits of competition in their report, can continue in perpetuity; such a sustained level of benefits is impossible. Kirsch and Morey argued that the losses are actually part of the business cycle. In order to accurately anticipate the benefits of competition, GED should have incorporated the "bust-boom" phenomenon of the electric utility industry's natural business cycle.

- The study wrongly assumed that traditional utilities will make generation investments that are inferior (less efficient) to those made by competing firms

[3] This study was also commissioned by the NRECA as a critique of the results of the GED Study.

both during the study period and on into the future. This assumption accounts for 1/3 of the calculated benefits. The assumption was wrong because the per MW capital cost for investments in new generation only counts for part of the overall cost of generation that consumers pay for power.

- Fuel cost was another component that is not addressed. As has been dramatically demonstrated since 2003, the cost of natural gas has sufficiently changed the price of delivered power. Furthermore, industry investment before 2003 in gas-fired technologies is currently greatly impacting the market. Neither of these parameters was addressed in the study report, thus skewing the conclusions.

- The report ignored the costs of RTO operations. The authors should have taken into account the estimated $1.6 billion on RTO operational costs for the 1999-2003 study period. If this cost were incorporated into the analysis, the benefits would have greatly decreased. In fact, Kirsch and Morey conclude that, after correcting for GED's most problematic assumptions, the consumer has actually experienced a net loss as a result of electric utilities competitive markets.

(vii) Spinner Response to CERA and GED Studies -- Virginia's very own Howard Spinner, Director, Division of Economics and Finance, of the Virginia State Corporation Commission, has provided his own views on two of the studies discussed above (the CERA and the GED Studies) in his paper titled "A Response To Two Recent Studies That Purport To Calculate Electric Utility Restructuring Benefits Captured by Consumers," (November 2005). (See Attachment 6.) Spinner outlined his thoughts of what he believed to be "conceptual flaws" in each of the studies in question. Spinner questioned the fundamental philosophy of both studies that conclude that "savings" to consumers resulted from losses realized by the competitive generator arena. The problem Spinner highlighted is that the methodologies used in these two studies to prove benefits of competition did not address "long-term impacts on capital formation, capital cost and operating expenses" which, if properly addressed, would lead the study's conclusions to different outcomes.

(viii) ESAI Study -- In October 2005, PJM released a commissioned study by Energy Security Analysis, Inc. ("ESAI"). The purpose of this study, written by Edward N. Krapels and Paul Fleming, was to review the impact of the expansion of PJM on the classic PJM area as well as the new service areas (Ohio, Kentucky, Virginia, West Virginia, Illinois, Indiana and Michigan). The study assessed the benefits of the increase in dispatch efficiency, improvements to market liquidity, changes in the transmission flows and the proposed Reliability Pricing Model. It concluded that over the past several years, wholesale electricity customers have saved more than $500 million a year as a result of the expansion of PJM into the Midwest and Southeast, resulting in a full RTO as one system, as compared with separate dispatch of disaggregated areas.

The study also found that PJM market integration has resulted in innovations that benefit the industry. Examples of such benefits included price transparency, rules for asset interconnection and open rights to use the transmission system. The study supported the Day 2 market mode, stating that this model allows buyers and sellers to hedge their risks effectively. The bid-ask spread is decreasing, which increases liquidity and helps reduce transaction costs for buyers and sellers. It also supported PJM's new capacity-market plan, the Reliability Pricing Model (RPM), which the authors concluded would stimulate investment in resources. It stated that market integrations have stimulated substantial growth in electricity trading. Increased diversity of supply has led to increases in import-export trading.

To that end, the study found that there is great value in a market where risks can be effectively hedged, bid-ask spreads are small, and where there is high diversity in the portfolio of power generating facilities. It concluded that the liquidity and diversity of the expanded PJM would yield savings to electricity consumers of $700 million to $1.4 billion per year. (See Attachment 7.)

Old Dominion is in the process of carefully reviewing the ESAI study. At this point, it appears ESAI's reliance on a heat rate analysis based on natural gas as the marginal unit to assess dispatch efficiency may not provide the most accurate assessment of efficiency as the marginal unit is often coal. Additionally, assuming that suppliers bid to recover their variable cost (as did ESAI) as opposed to maximizing profits will affect the results. The conclusions on efficiency based on FTR pricing and congestion revenue appear to be circular and the relationship between bid-ask spreads appears to be more relevant to assessing a lack of arbitrage opportunities rather than a lack of market inefficiencies.

(ix) <u>Synapse Studies</u> -- Addressing another very contentious market component, Synapse Energy Economics Inc. has prepared several reports after studying PJM's capacity market design. The market design has been called the Reliability Pricing Model (RPM). (See Section B for more details.) In the first report, which was prepared for the Pennsylvania Office of Consumer Advocate, the authors, Paul Peterson, David White, and Bruce Biewald, analyzed the revenues that existing, large base load generation units are receiving from the capacity market structure and what these same units would receive in the future under both the capacity market structure and the then proposed PJM RPM ("Capacity Revenues for Existing, Base Load Generation in the PJM Interconnection, A Pennsylvania Case Study," Synapse Energy Economics, June 10, 2005, Synapse.) (See Attachment 8.) The authors concluded that setting capacity prices under RPM significantly increased annual capacity revenues for these large generation units. They stated that these revenues are hard to justify, as they do not relate to financial hardship or enhanced services. They concluded by questioning how the RPM-type compensation mechanism can produce wholesale power rates that meet the "just and reasonable" standard under the Federal Power Act.

In the second report titled "An RPM Case Study: Higher Costs for Consumers, Windfall Profits for Exelon," Synapse Energy Economics, October 18, 2005, prepared for the Illinois Citizens Utility Board, these same authors looked specifically at the capacity revenues of nuclear generating facilities operated by Exelon Generation in northern Illinois. (See Attachment 9.) The authors highlighted that the RPM utilizes an administrative process to determine the market price of capacity resulting in higher prices than the current market would sustain. As a result of these higher prices, generators gain windfall benefits at the expense of ratepayers, with no guarantee that new capacity will be built. The authors conclude by questioning the efficiency of the RPM-type compensation mechanism.

The third study by these same authors (Ezra Hausman, Paul Peterson, David White, and Bruce Biewald, "RPM 2006: Windfall Profits for Existing Base Load Units in PJM. An Update of Two Case Studies," Synapse Energy Economics, February 2, 2006), also prepared for the Pennsylvania Office of Consumer Advocate, took a close look at the Reliability Pricing Model (RPM), filed at the Federal Energy Regulatory Commission in August 2005. (Ironically, a number of deficiencies PJM seeks to address reflect competitive market "successes" in some of the above reports.) The authors of this study continue to express concern that capacity prices as well as capacity revenues will rise significantly with the implementation of RPM. They concluded that RPM represents a major windfall for owners of base load generation at the expense of consumers, and find that "RPM is an inefficient and arbitrary price-setting scheme that will lead to windfall profits for generators, much higher costs for consumers, and no guarantee of increased reliability." (See Attachment 10.)

(x) Department of Energy Study -- The U.S. Department of Energy's Office of Electricity Delivery and Reliability sponsored a report prepared by Joseph H. Eto and Bernard C. Lesieutre of the Lawrence Berkley National Laboratory and Douglas R. Hale of the Energy Information Administration entitled "A Review of Recent RTO Benefit-Cost Studies: Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies," December 2005. (See Attachment 11.) This study evaluated 11 RTO benefit-cost analyses conducted between 2002 and 2004 and made recommendations to improve future studies. The document provides an excellent primer for some of the underlying economic theory behind proposed efficiency improvements. Of particular interest is the conclusion that "[t]aken as a whole, it is difficult to draw definitive conclusions from these studies because they have not examined potentially much larger benefits (and costs) resulting from the impacts of RTOs on reliability management, generation and transmission investment and operation, and wholesale electricity market operation." Among the studies evaluated are those in support of AEP and DVP's integration into PJM.

B. Proceedings Before the Federal Energy Regulatory Commission

A quick review of the number of proceedings currently before the Federal Energy Regulatory Commission ("FERC") addressing significant components of wholesale market design demonstrates we have not yet attained a workably competitive wholesale arena. Of the numerous proceedings currently before FERC that could significantly affect the viability of competitive wholesale markets of particular concern are:

- Reliability Pricing Model (EI05-148 and ER05-1410)
- Identification of beneficiaries, allocation of costs for transmission and long term regional rate design (EL02-111, ER05-6, ER05-6, ER06-456, EL06-50, EL06-54, ER06-954, ER06-880)
- Marginal losses (EL06-55)
- Market monitoring (ER06-826, AD06-7)
- NERC and ERO reliability Standards (RM06-1, RM06-16)
- Long term transmission rights (RM05-17)
- Revisions to the Open Access Transmission Tariff rules (RM05-25, RM05-17)

While all of the above have the potential to greatly influence the long-term viability of a competitive wholesale market, of particular concern is PJM's proposed Reliability Pricing Model (see Section A (ix) above). On August 31, 2005, PJM filed with FERC to modify its existing capacity rules to address "serious inadequacies." PJM notes in its filing that the current capacity adequacy rules have proven to be unjust and unreasonable because they (1) do not look far enough into the future to secure capacity in a timely fashion relative to reliability needs; (2) lack an important locational element; (3) are not providing sufficient financial incentives for supply additions, and (4) unchanged, will not ensure the future reliability of the region. In reality, PJM transmission infrastructure has not kept pace with load growth. Steps need to be taken to address those problems, including modifications to the Regional Transmission Expansion Plan ("RTEP"), and incorporating a methodology to evaluate a declining generation profile. Transmission planning needs to evolve to reflect the current competitive, non-integrated resource planning environment. The Commission issued an initial order on April 20, 2006, ruling on several issues and leaving others to a technical conference and paper hearing.

Old Dominion and a number of other entities representing load interests take serious issue with this proposal and the subsequent Commission order. As proposed, RPM has the potential to increase costs between $5 to $12 billion annually with no assurance that new generation will be attracted to build in constrained areas such as Washington, D.C. The order ignores significant information that contradict PJM assertions in support of this construct, as well as concurrent initiatives on local market power, transmission planning and rate design. As an example, based on PJM's December 2005, Regional Transmission Expansion Plan (RTEP), less than $300 million had been invested in transmission upgrades not associated with new generation interconnections since the RTEP process began. Assessing available Energy Information Administration ("EIA") data for new generation construction over that same time period indicates over $9.5 billion had been invested in new generation. The order ignores the severe locational aspect of PJM's perceived deficiencies as well as less onerous and broad alternatives to address legitimate local concerns. Additionally, as articulated in the October 19, 2005, comments of the Virginia Office of the Attorney General's Division of Consumer Counsel, implementation of such a construct will effectively negate anticipated benefits to Virginia of Dominion Virginia Power's ("DVP") integration into PJM by between $298 to $314 million, dependent on the low or high-end benefit case as submitted on June 25, 2004 by DVP. (See Comments of the Virginia Office of the Attorney General's Division of Consumer Counsel under ER05-148, dated October 19, 2005, pg. 4.)

Old Dominion adamantly opposes RPM as currently proposed and is actively involved in all available forums to achieve a more favorable resolution to this initial order.

C. Effect of Regulatory Changes in Other States

Recent rate increases in retail choice states to the north should be of interest to the Commission. As pointed out in an editorial printed in the Washington Post on April 16, 2006, by former SCC Chariman Hullihen W. Moore, residential customers of Baltimore Gas & Electric in Maryland have experienced an increase of 72%, and in Delaware residential customers will be hit with a 59% increase and industrial customers will see rates doubled. Additionally, Delmarva Power recently filed for an increase in rates to their customers on the Eastern Shore of Virginia to the tune of as much as 65% due to purchased power contracts from an affiliate in the PJM market.

In an editorial opinion published on May 14, 2006, in the Richmond Times Dispatch, the author cited a report on deregulation in The Christian Science Monitor stating that in addition to the increases in Delaware, Pennsylvania consumers are paying rates that are fifty percent higher than before deregulation, New York's retail rates have increased 16%, and other New England customers are paying around 15% more than before deregulation. The Christian Science Monitor report also noted that "thirty-four states have repealed, delayed, suspended, or are no longer considering deregulated electricity for retail customers." The utility-pricing consumer advocate in Pennsylvania, Irwin Popowsky, who at one time was a proponent of deregulation, is quoted to say that "[t]his isn't the way it was supposed to be," and added that competition has not transpired as promised and rates have skyrocketed.

It will be vital that the Commission and the legislators in Virginia be fully cognizant of not just the status of the energy industry in surrounding states, but also to stay in tune with the root causes of why or why not the effort by other states to develop an electric retail market has materialized in the fashion as originally intended.

2. Status of Competition in the Commonwealth

In its Fifth Annual Summary on the Status of Retail Electric Competition in the Commonwealth (dated September 1, 2005), the Commission reported its observation that, thus far, the integration of Virginia's two largest investor-owned electric utilities into PJM had not led to greater levels of retail competition. This is still true today. Even with the Competitive Transition Charge (CTC) set at zero for the majority of all rate classes of all the utilities, competitive service providers ("CSPs") still find little economic incentive to enter Virginia's retail market. There are 3.2 million electricity consumers in Virginia who have the right to choose an alternative supplier. There are twelve competitive service providers licensed in the Commonwealth, only six of which are registered with an incumbent utility; however, none is offering to sell energy that would allow those consumers to save money. Approximately 1,400 customers are purchasing electricity from one supplier offering a more environmentally-friendly source of electricity; however, that electricity is priced at a higher rate than the capped rate of the customers' incumbent utility.

This is by no means a reflection on the efforts exerted by the Commission. In the six years since the Restructuring Act was adopted and implemented, the Commission has endeavored to provide regulatory certainty and erect the infrastructure to enable restructuring. However, despite all its efforts, the competitive retail market is floundering due to constraints surrounding the wholesale market.

In the same status report referenced above, the Commission concluded that robust retail competition has yet to develop. Old Dominion agrees with the Commission's conclusion. It is clear that, at least at present, retail competition has not arrived in Virginia as witnessed by the simple fact that the incumbent utilities are still providing nearly all of the electric energy supply to customers throughout Virginia. Additionally, the problems that have impeded the development of retail competition in Virginia and other regional markets continue unabated.

Price is not the only component of a competitive retail market; choice is important as well. Perhaps one approach that should be revisited is an incremental rather than universal evolution of choice similar to the experience of the natural gas industry. The gas industry largely began offering choice incrementally – only to those customers that could easily handle choice and wanted it – transportation customers first and then gradually moved into other market areas as demand for the new "choice" offering increased. The natural gas industry within Virginia and across the country has created some level of "choice" for customers within its marketplace. Clearly, there are some areas within the gas industry model that can be readily improved upon, but there may also be some lessons to be learned.

Retail "choice" or "competitive retail markets," however they are constructed, need to be made available equitably so that no consumer and/or member is harmed by the election of another. This premise needs to be adhered to no matter the final policy, program or activity.

3. Recommendations to facilitate effective competition in the Commonwealth

The fate of retail competition in Virginia is tied not only to that which occurs in the Commonwealth, but what occurs regionally and nationally. As discussed above, the wholesale market needs more work. Additionally, we must assure that we have availed ourselves of all useful information and analyses. We then need to talk among ourselves.

Toward this end, Old Dominion recommends the Commonwealth strive for more local and regional transmission, become an active and vocal participant in the PJM and federal debate and initiate dialogue within the Commonwealth relative to retail markets.

A. Need for Local and Regional Transmission

With the integration of Virginia's two largest investor-owned utilities into the PJM footprint, there are many issues to be resolved to attain the robust wholesale market that is necessary to facilitate effective competition in the Commonwealth. Of primary concern is the general inadequacy of the transmission system to support a competitive market and the lack of recent expansion of the grid. PJM has even admitted that it has "the transmission system on life support as opposed to that robust system" that it wants. Additionally, PJM recognizes the failure of its planning process thus far to go beyond the shortsightedness of upgrades that incrementally address the next reliability violation, and to focus on the long-term needs of the transmission system for reliability and economics to support FERC's open-access and competitive goals. [Transcript of AD05-5 Technical Conference, April 22, 2005, Audrey Zibelman, at pp. 66, 71-73.]

In order to continue down the path toward competition, the transmission grid must be enhanced. To date, load serving entities have struggled with the dual problem of increased congestion costs experienced by load with the implementation of Locational Marginal Pricing ("LMP") within PJM and the inadequacy and insufficiency of Financial Transmission Rights ("FTRs") to hedge against increased and sometimes excessive congestion costs. Notwithstanding price signals arguably sent by LMP, there still remains insufficient transmission infrastructure to relieve congestion in many areas within PJM.

The evolution of the electric utility industry from a vertically-integrated monopoly into unbundled competing enterprises requires further progress toward "openness" of the process and the methodological approach to transmission planning in this new environment. The current PJM planning process must be improved in order to facilitate this progress. The process of selecting transmission projects to address reliability violations and congestion must be broadened to include meaningful input from affected stakeholders. These inputs fall across the broad spectrum to cover issues such as reliability, economics, operational performance, generation retirement scenarios, and regional planning. Following are recommendations Old Dominion believes would greatly improve grid expansion and reliability:

Reliability: PJM evaluates reliability of the transmission system based on Reliability Council, Transmission Owner ("TO"), and limited PJM criteria for the subset of transmission facilities turned over to PJM control (PJM Monitored Facilities). For all other facilities, each TO uses only its own set of criteria. There is a fine balance as to what is appropriately standardized among all TOs, as far as what may be turned over to an RTO, versus what may need to be different among TOs. Nonetheless, additional consistency would be valuable. Old Dominion recommends developing additional planning criteria for local facilities included in PJM's security-constrained economic dispatch (PJM Monitored Facilities) and that such facilities be excluded from that dispatch until such criteria is met and maintained. Old Dominion further recommends that TO planning criteria, which happens to be utilized for PJM monitored facilities, be more standardized and subject to modification from affected loads and PJM itself through PJM stakeholder processes. Each TO has determined what it will turn over to PJM. Although PJM has high-level criteria for facilities under its control, this "turn over" process could be greatly improved by adding consistency.

Economics: The current PJM economic transmission planning process has resulted in no discernable new transmission construction, predominantly due to the evaluation of only "unhedgeable" congestion. PJM staff is working hard to address the concerns of its various stakeholder groups as it develops its enhanced planning process. Old Dominion is highly supportive of their efforts. There are, however, a number of stakeholders who benefit from a continued dearth of transmission. As such, PJM needs the strong support of the Federal Energy Regulatory Commission, as well as the support of the Organization of PJM States, INC. (OPSI), to accomplish its mission.

Operational Issues: Operational issues need to be addressed in the process so projects that relieve the PJM operators' concerns can be constructed. These are projects that don't necessarily relieve a specific reliability problem but provide significant operational and economic benefit. Projects could be proposed by PJM's operations group and evaluated by the PJM Planning Committee on a case-by-case basis.

Generation Retirement: In most jurisdictions in PJM, generation is no longer a regulated asset. Therefore, there must be recognition of a higher level of uncertainty for specific generation assets in our transmission planning. PJM's transmission planning process has not evolved beyond that which was appropriate for vertically integrated monopolies, controlling both transmission and generation and trading them against each other. With generation as a competitive asset with no obligations to load, transmission planning must assume that certain generators may no longer be available. PJM has experienced transmission reliability problems caused by unforeseen generation retirements. Scenario analysis to address such a possibility needs to be included in PJM's planning process now, rather then later. To illustrate, suppose that a generator announces it will retire in 90 days. This near immediate retirement may require transmission upgrades that take years to get into place. In the meantime, the system would be operated unreliably and/or Reliability Must Run contracts may be used.

Regional Planning: PJM has exerted an admirable effort in developing a regional transmission plan. Old Dominion would propose that there are improvements and enhancements that would benefit all users. Projects planned via a modified PJM stakeholder process (more open and inclusive of all stakeholders), accounting for longer-term cost benefits based on gross congestion and accounting for generation retirements, should be part of the regional plan. Establishment of clear criteria, in conjunction with not only the traditional stakeholders but also OPSI, will be critical. The criteria should be broader than simply identifying beneficiaries of one peak hour of load flow and should assess the benefits of economic development as well as national energy independence. For example, load in the east of PJM will benefit from economic coal from the west. Load in the west will in turn benefit from increased production from existing and new capacity.

Additionally, evaluation of projects should also strongly consider enhancements and upgrades to existing infrastructure. Such a requirement will optimize solutions as well as provide guidance to siting new facilities based on upgrade opportunities. For long lead-time projects, PJM should develop an approach to relieve congestion until such time as that project goes into service.

<u>Long Term Regional Rate Design</u>: A key aspect to new transmission construction is resolving how it will be paid for. Old Dominion believes application of a highway-byway regional transmission rate represents a reasonable solution in harmony with the physical uses and flows of the grid. Some facilities are clearly local and resolve local issues; others provide inter-regional benefit.

PJM is beginning to make good progress moving toward a longer planning horizon and evaluating economic as well as reliability-based projects. PJM needs strong support, however, to complete this process as well as integrate generation retirement scenarios into its transmission planning function.

B. Active Participation In PJM and other Regional and National Forums

With the Commonwealth's integration into PJM, it is imperative to be a frequent and vocal participant in the PJM stakeholder process. Old Dominion, DVP, AEP and APS have been active participants. The Commonwealth's Office of the Attorney General's Division of Consumer Counsel has also been participating since 2005. As the representative of Virginia consumers, the AG's office needs adequate funding and staff to continue to be an effective participant in this forum. Additionally, the Virginia State Corporation Commission now has a forum via OPSI to make its views known to PJM. Active participation via this pathway will be required to protect the Commonwealth's interests. Finally, FERC is particularly receptive at this time to the views of the various states as it continues down the path to competitive markets and wrestles with federal and state jurisdictional issues. One-on-one dialogue with FERC provides another avenue to effectuate change. This type of interaction and frank exchange of views will be particularly important as the FERC resolves capacity market and market monitoring rules as well as revisions to its pro forma open access tariff.

C. Renew the Debate on the Type of Retail Energy Markets Needed Within the Commonwealth

Virginia and all of its stakeholders need to debate and decide the type of energy marketplace (whether it be a competitive "de-regulated" or a regulated market) best suited for the Commonwealth. This discussion would then shape a plan and timeframe to achieve that marketplace. A clear definition and understanding of the type of market desired by the citizenry is a necessary prerequisite. As a member-owned not-for-profit cooperative, Old Dominion believes that input from consumers of the Commonwealth is important and should be solicited. Discussion, debate, and most importantly, an answer to these questions will help guide Virginia, its energy industry, and its consumers into the future on this very important topic.

4. Conclusion

As shown in the discussion above regarding the competing studies, it is imperative that consumers and policy makers have an opportunity to get all the facts and the full story on issues of this vital import. And an effective way to achieve this awareness is to participate in the regional and federal processes and insist on logical and understandable answers. Significant points of awareness are:

- Economists are going for economic efficiency and not lower prices. We must bear this caution in mind as we assess our next moves to facilitate competitive markets in the Commonwealth.
- The electric utility industry, particularly the wholesale market, is still evolving, and many additional changes will be required in order to achieve the anticipated benefits of a truly competitive wholesale market.
- PJM's proposed RPM capacity construct has the potential to take an additional $5 to $12 billion annually from customers in PJM with no guarantee of improved reliability or economic efficiency.
- Transmission planning needs to evolve to reflect the current unbundled, non-integrated resource planning environment.

The journey to competitive markets is not complete. Throughout this process, Old Dominion is dedicated to working toward a broadly beneficial outcome for all Virginians. We caution that the environment must be developed appropriately for competitive markets to truly exist. A competitive retail market cannot develop if the wholesale market is not mature.

To date, from a retail standpoint, there has been no competition in Virginia, with the small exception of those consumers taking advantage of environmentally-friendly energy at higher rates. Old Dominion's member owner distribution cooperatives are generally and increasingly concerned with increasing power costs throughout the industry. They are also concerned of the possibility of achieving a "competitive" retail market that has consistently higher prices.

Renewed, healthy debate over the need for and type of retail energy markets required by the Commonwealth today and in the future is something we should commit ourselves to as an on-going demonstration of all stakeholders to the long-term best interests of the citizens of the Commonwealth.

It is imperative that the legislators and other stakeholders in the Commonwealth of Virginia dig beneath the headlines to fully comprehend the impact of competition at the wholesale level in order to assess the status of retail competition within Virginia. As such, it is prudent for the Commonwealth to continue assessing the successes, or lack thereof, of restructuring initiatives nationally, regionally, and at the state level; and to be prepared to make changes should they be necessary.

The Commonwealth must also take an active role in the regional and national debate on wholesale market development to assure that actions in that arena do not preclude our vision of the future.

Old Dominion appreciates the opportunity to participate in your assessment and stand ready to help you in any way we can.

Sincerely,

Edward D. Tatum, Jr.

Edward D. Tatum, Jr.
AVP Rates & Regulations
Old Dominion Electric Cooperative

Attachments

Please note the referenced attachments are voluminous and will not be duplicated here. They are available at: http://www.scc.virginia.gov/division/eaf/comments_comp.htm

Association of Electric Cooperatives

Virginia, Maryland & Delaware

June 12, 2006

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

Dear Mr. Eichenlaub:

The Virginia, Maryland & Delaware Association of Electric Cooperatives (the "Association") has reviewed with interest the comments filed in this proceeding by Dominion Virginia Power, Constellation New Energy, the Virginia Citizens Consumer Council, the Virginia Committee for Fair Utility Rates, Old Dominion Electric Cooperative (which serves many of our members and with which we are federated) and Mr. Urchie Ellis. We appreciate this opportunity to provide these comments in reply to those referenced above.

I. Introduction

Interest in the status of electric competition in Virginia, which has been so well articulated by all of the commentators, raises unquestionable concern that the stakes are enormously high for all Virginians, and also raises a number of questions. The first question these proceedings and the comments already filed herein bring to light is whether industry restructuring is still, or ever was, the right choice for Virginia.

There can be no serious doubt that our electric energy infrastructure is fundamental to every facet of our economy, and every sector of our society. The interests of consumers (both large and small), utilities (both for-profit and not-for-profit), investors, citizens and our legislators are important, as are the effects on the future of our commonwealth.

Virginia's electric cooperatives have a perspective that is unique among the stakeholders in this industry. As utilities, on the one hand, they have, along with investor-owned and municipal systems, the heavy responsibility and duty of a public utility. Their experience has taught them that the highest level of vigilance and care is continually required in order to reliably and safely deliver that most vital commodity – electricity – to every meter on their systems. They have undertaken the enormous capital commitments necessary to build, maintain and grow an electric utility system.

As cooperatives, on the other hand, they are unlike investor-owned utilities in that they serve a single interest – the consumer. Even municipal utilities, as government-owned enterprises, are subject to pressures and considerations that may sometimes differ from the cooperatives' sole cause and object – the safe, reliable delivery of electric energy at the lowest, possible cost. The members of a cooperative may struggle over what is the best way to achieve their mission, but the mission itself is never in doubt. It is vital for the cooperatives to put at the highest level of priority the best interest of the consumers who, as ratepayers and voters, bear the ultimate risk or enjoy the full benefits of a competitive environment.

The Association has long believed that the cooperatives' unique perspective, incorporating the experience of a utility with the undiluted motivation of consumer ownership and direction, aligns it, more closely than is possible for other stakeholders, with the ideal perspective for utility policy analysis. The cooperatives stand fully in both camps. They are fully utilities. They are fully electric consumer associations.

II. Reply to Comments

A. Deregulation has not brought significant benefits to consumers.

The proponents of deregulation sidestep the central issue of the status of competition by reciting a long list of purported benefits of deregulation to the consumers. In its comments to this proceeding, Dominion Virginia Power states that Virginia's restructuring program has "produced significant benefits for consumers," as well as promoted efficiency in the industry. They state that retail competition will come inevitably once wholesale prices dip below capped rates. Many of the purported benefits, however, are benefits, not of competition, but of the artificial shields, such as capped rates, that have been implemented to protect consumers during the intended transition to deregulation. Capped rates are not a function of competition; they are a function of legislation. And while competition could thrive if wholesale prices drop, it is not hard to see that in jurisdictions where it has "succeeded" so far, it is not because of low wholesale prices, but because of very high retail prices.

Indeed, recent developments in Virginia demonstrate unequivocally that wholesale prices, far from dropping, are increasing dramatically. The Town of Front Royal reports a 76% increase in its wholesale power rates.[4] Craig-Botetourt Electric Cooperative's wholesale rates recently increased an average of 18%. Conectiv is currently seeking a 49.5% increase for its ratepayers on Virginia's Eastern Shore. The experience in neighboring states appears to be even more severe. As such, what we are experiencing is an increase in Virginia's electric utility bills as the price gravitates towards market based rates. While Virginia once had lower than average electric utility rates under a regulated cost-based environment, deregulation will inevitably increase our electric rates to meet market based prices.

Dominion Virginia Power also states that interests in retail competition is still strong, citing that there are currently six competitive service providers and six aggregators licensed by the SCC. However, none of those have approached the cooperatives for certification to provide offers to their consumers. With the exception of the one supplier providing "environmentally-friendly" energy, it is our understanding that no offers are even available to consumers of the investor-owned utilities. As has been pointed out in a number of the comments, the wholesale market is not ripe to produce an effective retail market.

Dominion Virginia Power concludes their comments by stating that Virginia's restructuring initiative has shifted the risk for "billions of dollars in new cost and investments from utility customers to the companies and their shareholders." While that may present itself as a benefit to their consumers, the cooperative's customers are its shareholders, and thus the ultimate risk bearer.

It is important to note that from the outset, there has never been a political outcry from the mass market (ratepayers/voters) for deregulation. Restructuring developed based on an expectation of lower cost to consumers as a result of competition and the associated opportunity for choice. In fact, competition never materialized. Industry groups that once supported deregulation based on the expectation of competition

[4] "Town Ironing Out New Budget," *Northern Virginia Daily*, June 5, 2006.

and the associated lower electric utility bills are now facing much higher electric rates once the restructuring transition period expires on December 31, 2010. In fact, in their comments to this proceeding, the Virginia Committee for Fair Utility Rates (CFUR) urges the State Corporation Commission to consider the fact that "[e]lectric restructuring has not worked so far in Virginia, and recent developments do not bode well for its future success" as it develops recommendations for their report to the Commission on Electric Restructuring.

Deleted:

B. The Retail Market Cannot be Effective without a Successful Wholesale Market.

The comments submitted by Old Dominion Electric Cooperative provided a series of studies demonstrating that the jury is still out on whether or not wholesale competition is successful. It is difficult to make any argument with this sizable body of evidence that competition at the retail level can be implemented in any effective manner until such time that there is an effective wholesale market. The transmission and generation constraints, the price models used to determine market rates, along with a host of other issues (e.g., fuel costs volatility,) that arise in the wholesale arena provide no assurance that there will be true wholesale competition at any point in time in the near future. Without an effective wholesale market, competition in the retail sector cannot develop.

III. Conclusion:

In examining the status of competition in Virginia, it is best to separate competition from deregulation. We need to be perfectly clear that the cooperatives are not opposed to competition. We recognize that the prospect of an effective competitive market that produces maximum value from capital investment and offers customers a wide variety of choices (including lower prices) is enticing. The objective of restructuring electricity markets is to achieve more efficient allocation of resources with lower prices as a desired result. However, the model implemented in the Commonwealth is not working and the facts do not refute that. As stated above, deregulation was embraced with the expectation of lower cost as a result of competition. In reality, it meant a shift to a market based reality, and in a market such as this prices gravitate towards the average. Those with prices below the average will see an increase. Since consumers in Virginia had long enjoyed a cost of electricity below the national average prior to the restructuring, it seems to reason that a promise of lower prices will go unrealized. And this brings the discussion back to the question posed early on in this response to comments, "Is industry restructuring still, or was it ever, the right choice for Virginia?"

Despite enormous cost and effort, there is no meaningful, effective retail electric competition in Virginia. As a consequence, the Association wishes now to pose these additional questions:

1. Without regard to whether Virginia should ever have made the choice to go down the path of deregulation of retail electric service, is it the right path now for Virginia's future?
2. If not, is it possible to return to cost of service regulation, and what challenges would we have to overcome to do so?
3. Are there other, more important objectives than economically efficient competition, such as transmission system development, that would be a better focus for industry stakeholder efforts?

The Association asks that these questions be included in the Commission's report to the General Assembly on the status of competition in Virginia.

As a final note, I would cite the comments on Wholesale and Retail Electricity Competition, submitted by The Alliance of State Leaders Protecting Electricity Consumers to the United States of America electric Energy; Market Competition Interagency Task Force and the Federal Energy Regulatory Commission (Docket No. AD05-17-000). While these comments are specific to national policy, I would argue their relevance to Virginia:

"The ultimate test for evaluating any approach to the delivery of electric service should be its effect on consumers. [National] policy should seek to ensure that electric power is delivered to end users at a reasonable cost and with adequate reliability. If that result is best achieved through competition, then electricity policy should favor competition. If that result is best-achieved through reliance on regulated monopoly, then electricity policy should focus on regulation. If that result is best achieved through a hybrid policy that mixes competition and regulation, then a hybrid approach should be taken. The determination of which approach is most appropriate should be based on an analysis of relevant facts rather than on economic theory."

Again, we appreciate the opportunity to respond to comments to these proceedings. Please contact me at (804) 968-4084 should you have any questions.

Sincerely,

Susan Rubin
Assistant Vice President – Governmental Affairs

cc: CEOs, Virginia Member Systems

May 22, 2006

Mr. David R. Eichenlaub
Assistant Director, Economics
Division of Economics and Finance
Commonwealth of Virginia
State Corporation Commission
1300 East Main St.
Richmond, VA 23218

Re: ***The Commission's Sixth Annual Report to the Commission on Electric Utility Restructuring and the Governor***

Dear Mr. Eichenlaub:

Constellation NewEnergy, Inc. ("Constellation NewEnergy") appreciates the opportunity to offer ideas to assist the Commission in developing effective competition in the Commonwealth. As you are aware Constellation NewEnergy is a licensed Competitive Service Provider in the Commonwealth.

In addition, Constellation NewEnergy is licensed or certified to act as an alternative retail electric supplier to serve customers located in more than 20 states and provinces throughout the United States and Canada. Constellation NewEnergy has over 15,500 MW of load under contract with over 10,000 retail customers. In the PJM region, Constellation NewEnergy serves approximately 1,200 MW of industrial and commercial load. Our customers include universities, manufacturers, schools, hospitals, hotels, retail stores, and office buildings.

The Status of Competition in the Commonwealth

Retail competition continues to evade the Commonwealth, and will likely continue to do so during the period when utility rates are capped below market prices. While the promise of competition is in the development of products and services that meet customer needs, markets develop first based on price competition. Given the persistence of rate caps in the Commonwealth, it is not surprising to find a lack of interested competitive suppliers providing customers with competitive offerings. Until such time as those rate caps expire, this situation is unlikely to change. In the meantime, we urge the Commonwealth to begin an examination of the utilities' rate designs to ensure that distribution and transmission service costs are properly allocated and do not in any way subsidize generation service. Transparency of costs and ability to compare rates with prices will be a critical element in the development of competitive markets.

As we noted in our comments in the Commission's Default Service investigation, the Commission and the Commonwealth would be well served by the initiation of a Working Group to explore the design of default service after the expiration of rate caps in the Commonwealth.[5] Lessons learned in the PJM retail markets, as well as other U.S. markets, could prove very useful in shaping the future of Virginia's retail electric market. The Commission Staff has a long and successful history of effectively facilitating Working Groups and we urge the Commission to initiate a Default Service Working Group that would report to this Commission, the Commission on Electric Utility Restructuring ("EURC") and the Governor.

1. The Status of the Development of Regional Competitive Markets

a. Wholesale

An important step in Virginia's transition to competitive markets occurred on May 1, 2005 when Dominion Virginia Power became a member of PJM. The integration was by all accounts successful. While membership in PJM in and of itself is not

[5] *See* Comments of Constellation NewEnergy, Inc., Case No. PUE-2006-00001, March 24, 2006.

sufficient to develop retail choice, we note that success in retail markets is more immediate and comprehensive where there is an organized and vibrant wholesale market. PJM is by no means perfect but in our experience is among the best of the organized markets. Members of PJM benefit from the improved system reliability, increase in available resources during peak periods and access to economic power supplies. In addition, PJM continues to address issues of importance to the market participants via the stakeholder process. We are encouraged by the development and growth of the Organization of PJM States ("OPSI") as a mechanism for the Commission (and other Commissions) to voice their views to PJM and the stakeholders. OPSI provides the Commission a means to work with other Commissions within PJM on issues of mutual interest. This involves the Commission early on in the stakeholder process allowing for valuable input and comment as the stakeholders work toward consensus.

b. <u>Retail</u>

Within the PJM footprint, retail markets continue to develop and PJM continues to develop new products, such as PJM's integration of load response into their ancillary service markets. While the expiration of residential rate caps that froze rates to their 1993 level in the BGE territory has recently generated significant political interest, commercial and industrial customers have displayed a willingness to participate in the competitive market and that desire has led to the development of a competitive market for those rate classes.

Within the classic PJM region, the number of commercial and industrial customers choosing alternate energy suppliers continues to demonstrate a high degree of switching activity. In Maryland, the switching statistics for commercial and industrial customers show that 58.8% of the commercial and industrial customers have switched to competitive suppliers.[6] The March 2006 switching rates for commercial and industrial customers in other classic PJM regions were as follows also demonstrate a high degree of switching among commercial and industrial customers. In the Duquesne Light Company service territory in Pennsylvania, 59.2% of industrial and commercial customers have switched to a competitive electric supplier.[7] In the Pepco service territory in the District of Columbia, 44.6% of industrial and commercial customers have switched to a competitive electric supplier.[8] While switching statistics are not the only metric on which to judge the success or development of retail markets, they are one important factor.

Another indicator of retail market development in the commercial and industrial sector is the number of retail competitors vying for the commercial and industrial business, putting downward pressure on prices and creating new products and services. In Maryland, there are nineteen (19) electric suppliers serving large commercial and industrial customers.[9] There are also a significant number of retail competitors participating in the DC and Delaware markets as well as in the market behind the one utility in Pennsylvania whose rate caps have expired.[10]

Clearly, the high degree of switching activity demonstrates that customers have shown the willingness to participate in the marketplace and take electric service from companies that provide products and services that best meet their needs. In turn, the

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[6] *See* http://www.psc.state.md.us/psc/Electric/electricRestructuring.htm.

[7] *See* http://www.oca.state.pa.us/cinfo/instat.htm.

[8] *See* http://www.dcpsc.org/customerchoice/whatis/electric/electric.shtm.

[9] *See infra* Footnote 2.

[10] *See infra* Footnotes 2, 3, and 4. *See also* http://www.state.de.us/delpsc/electric/elecsupplierinfo.com.

participation by a large number of suppliers in the marketplace demonstrates that if the market rules are fairly and properly constructed, competitive retail electric suppliers will invest in the market and vie for the opportunity to provide service to customers.

Thank you for the opportunity to submit comments to the Commission as it prepares its report to the EURC and the Governor. Please do not hesitate to contact me should you have any questions or concerns.

Very truly yours,

Martha A. Duggan
Vice President, Business Development
Constellation NewEnergy, Inc.
111 Market Place, Suite 700
Baltimore, MD 21202
Phone: (703) 243-2535
Fax: (703) 243-6869
Email: Martha.Duggan@Constellation.com

URCHIE B. ELLIS
Attorney at Law Va. State Bar No. 5422
7900 Marilea Road
Richmond, Va. 23225 804-272-5923

May 1, 2006

Re: 6th Annual Report to the CEUR

To the Staff of the State Corporation Commission:

Current developments in connection with electric deregulation make it even clearer that the general public is at great risk and has all to lose if deregulation is allowed to continue. I renew the comments in my letter printed in the SCC Report of Sept. 5, 2005 (correct the typo in para. 4 where it should read "August 2002"). Virginia has had over 100 years of good electric service, at comparatively low rates, pursuant to SCC regulation, and it should not be lost.

We now see very serious problems close to home in Maryland, on the Eastern Shore, and in Western Virginia, and we do not see any prospect of any competition providing lower rates than we have long had from Dominion Virginia Power and other suppliers in Virginia. Recent news items from other parts of the U.S. also reflect the failure of electric deregulation.

Factors making it even more unlikely that we will ever get the lower rates that CEUR, and Dominion, and others, have predicted, are the natural gas and petroleum price increases and shortages. Nearly all of the predicted lower rates were to come from generating plants using those fuels.

The joining of PJM by several major Virginia power companies does not appear to offer any benefit to Virginia general public homeowner electricity users.

It is of concern to me that meetings are being held to discuss important aspects of this subject, and decisions on statutory changes are made, such as the recent change of fuel rate increase procedures, and the recent meeting involving PJM, with little of no input or participation from the few voices of the general public. I also remain concerned about the large political contributions being made by the vested interests, which adversely affect the general public voices and interests.

I again urge the Commission to make a strong report calling on the General Assembly to cancel electric deregulation and restore regulation to the SCC as fully as can be done in the present circumstances.The General Assembly and the Governor should call upon Congress tomodify the Federal Energy laws as necessary to permit complete restoration of SCC authority. This is a complicated subject and needs the expertise of the SCC Staff. The SCC has a Constutional and statutory duty to protect the public.

Respectfully yours,

Urchie B. Ellis

Status of Electric Restructuring in Virginia
2006 Assessment of the Virginia Citizens Consumer Council

Seven years after the passage of Virginia's Electric Restructuring legislation, it is the view of the Virginia Citizens Consumer Council (VCCC) that neither Virginia nor the nation is anywhere close to having an effective, fair, competitive retail market. For consumers, electricity is a basic necessity of daily life. Depending on where we live, the season of the year, and our specific needs, we depend on it to operate the heating or cooling systems that protect us from the weather, to pump our water, to cool and cook our food, and to run our life-sustaining medical equipment. Our communities depend on our traditionally low cost electricity for economic development and to help keep our tax payer provided school operation costs low. Electricity is not, for us, an investment. We want stability and guarantees for our electric supply, not a risk-reward relationship, especially when the system makes consumers responsible for most of the risk and guarantees us none of the reward.

Since the beginning of this venture, there have been pervasive structural problems that remain unresolved, so it is not surprising that the competitive market has not developed. All of the actions that have been undertaken to change the legislation to promote competition have, like the original legislation, been largely designed around the needs and desires of the industry, primarily, the investor owned sector.

1. Consumers are still not receiving competitive offers for electricity and there is no sign of impending choice. Until Virginia's average price for electricity increases sufficiently above the average in PJM, no competitor will find it economically possible to enter our market, especially since significant marketing and customer care dollars will have to be spent to gain notice above the incumbent utilities. It is not in the consumer interest for our prices to rise to this high level. When this occurs, consumers, businesses, and government will experience substantial problems paying the bill and the ramifications will be negative for all but the utility industry.

   Craig-Botetourt Electric Cooperative, and Radford and Salem's public power systems just signed a new long-term contract with AEP that they hope will help contain their costs. Last year those entities faced increases of 40-80%. After a one year contract (with AEP), this contract replaces one between Craig-Botetourt and AEP that had lasted 20 years. Since the market now drives costs, Craig-Botetourt customers are now paying more at the wholesale level than is an AEP customer located about a mile away pays at the retail level. Salem has informed it's customers that the new contract will help hold costs down in the long run, but that they still face increased rates after July 1.

   The fact that even in a "competitive" environment AEP has the market power to be able to win the contracts back, shows that Virginia consumers are not benefiting from the competitive market. AEP is benefiting from a situation that allows it to increase its revenue from these entities while still keeping the business.

Last year Craig-Botetourt, Salem, and Radford did not pass the entire cost increase to their customers, but in the future customers will have to pay the entire cost. These entities have no choice. Their only source of income is their customers and to continue to provide power, they musts charge consumers the real cost. Anyone curious about what the future holds for AEP and Dominion customers when the rate caps come off should study the current experiences of these entities.

2. Investor owned utilities are still not prepared to accept the risk – lows as well as highs – of a truly competitive market. Every action that has been taken in Virginia's electric restructuring has provided protection for the incumbents, especially actions that have been touted as being consumer benefits.

   Dominion repeatedly points to its calculated savings per consumer of $61-$74 per year during the capped rate period. However, because Dominion refused to allow a leveling rate case before rates were capped, at a time that energy rates were low and to address the fact that it was widely known that within several years of its last rate case it would be over-collecting costs, it is unfair for Dominion to claim such large savings. Further, few segments of the economy increase at a rate equal to or above the inflation rate every year, so it is unfair to assume that electric prices would absolutely have done so. Virginia's generation costs are still documented as being lower than those in most other states. It is more prudent to assume that they would have continued to be lower had rate-of-return regulation been kept in place.

   Virginia's legislation allows our utilities to be protected from large fuel price increases and increases in several other areas. However, from the outset, there was no parallel guarantee of prices dropping if utility costs dropped. Consumers have seen customer service decline as the primary cuts by utilities have occurred on the consumer's side of the ledger sheet.

   Consumers, even those not directly served by Dominion, have complained in recent years about waiting too long to have disrupted service restored. Craig Botetourt Electric Cooperative members found service disruptions to last longer and be more frequent since experienced Dominion staff retired and were replaced by workers based over an hour farther away from the substation that serves the Cooperative. Often disruptions that were once typically handled during the night wait until morning or for days, for example, and it generally takes the less experienced workers longer to complete repairs. The cooperative has been forced to take the extremely expensive option of buying back-up power from AEP, essentially buying power twice, to protect affected customers.

The commonwealth's electricity restructuring legislation also protected the incumbent utilities from taking any risk from stranded costs, even though the restructuring was something they requested. Our incumbent utilities refused to actually calculate stranded costs, instead convincing the Attorney General to use a current market price value to get the issue off the table. While stranded costs were expected to be recouped, Dominion earned enough that it made several significant investments to increase its ability to serve the market outside of Virginia and their executive compensation and stock returns remained comparatively outstanding. On the other hand, unlike Maryland consumers, Virginia consumers got no compensation for stranded benefits.

While Dominion tells customers and everyone else how much money customers have saved from capped rates, it is the company that has benefited the most. When the capped rates were extended, Wall Street approved, giving Dominion advantages due to the benefit of having guaranteed minimum income for longer than before.

Dominion asked the legislature to extend the capped rates as a means of defeating consumer legislation that would have stopped the restructuring process. It even volunteered to forgo annual fuel increases and to limit its requests for a fuel increase to one during the remainder of the capped rate period. It had just received what may have been the largest fuel rate increase in history when it took this action. The agreement did not hold since it recently convinced the Governor to send the General Assembly a provision to the Veto Session for it to revert to annual increases. This strategy meant that it did not have to go through full public consideration of the change that broke the agreement that kept restructuring in place.

In 2004, Dominion broke apart the broad coalition working for the legislation to stop restructuring, finding ways to resolve concerns of large electric users through contracts and adding opportunities to increase rates for AEP. In 2004, the State Corporation Commission Staff projected that Dominion's customers were paying $400 million per year more than they would have under rate-of-return regulation. This is equivalent to a 9-cent increase in the gasoline tax. While legislators are rejecting such an increase to improve transportation, a public good, they approved it when the money went to Dominion, an investor owned private business.

At the same time, Dominion asked the Federal Energy Regulatory Commission (FERC) to allow it to retroactively recoup the fuel costs accumulated under the capped rates from Virginia consumers after the capped rate period ends. This is not action that shows that the company is ready to accept the bad along with the good in a competitive market.

AEP's extraordinary earnings last year were attributed in the media to "favorable regulatory decisions." While AEP is no longer based in Virginia and its territory in Virginia is not significant enough to drive the earnings of the entire company, the increased rates approved for Virginia customers last year certainly contributed to that outstanding outcome for the company and its investors. Again, this shows that the company is dependent upon traditional regulation, not that it is adjusting to the inherent risk of a truly competitive market.

3. There remains no competitive solution for the need to entice building of new infrastructure, especially generation. The coal-fired plant that the legislature approved is not a competitive solution. The electric consumers of Virginia are on the hook to pay whatever the cost of that electricity for the life of the plant. That isn't competition! The default service customers who will have to pay for that electricity are likely to predominantly be the ones in difficult economic situations who can least afford to pay a premium for this basic life necessity. If these consumers cannot pay the entire cost, we can be assured that others will be forced to do it.

   If by some miracle the plant produces electricity at lower than market prices, consumers have no means of being guaranteed to benefit. In that case, the utilities will be free to sell the power to the highest bidder – not forced to sell it at its true cost, plus a reasonable investment return, to the citizens who are actually taking the risk for this project.

   The project now involves a broad coalition of electric utilities, but for the consumer, it remains a likely white elephant, whose price is still unknown. More than two years after passage of the legislation approving this facility, it is extremely disturbing to consumers that the cost and price estimates that our legislature and administration should have demanded before approval are still unknown. While the desperately needed employment that the project will provide to far southwest Virginia is important, it appears that the cost to all Virginians will not be worth the expenditure.

   All work on the project should cease until a reasonably based cost-benefit estimate, conducted by a reputable unbiased entity completely unconnected with and not directed or influenced in any way by our utilities, **proves** that it is worth pursing. Unless the risk level of this project is proven to be such that typical investors would put their money forward for it, Virginia consumers' legislatively approved commitment to pay for it should be rescinded. Legislators outside of the far southwestern area should realize that the voters they represent are going to be very unhappy when they are forced to pay significantly higher electricity bills to pay for this plant.

4. Since incumbent utilities have purchased most of the merchant power built in the state in recent years, there is again very little diversity in the ownership of generation. Again, this is not a condition conducive to a competitive market.

5. For the competitive market to operate as anticipated, more transmission will be needed. While the new AEP line in southwest Virginia is operational, clearly,

across the state and the region significantly more transmission is needed for competition to work. The PJM system of rewarding those who own transmission by keeping competition for its use tight, means that there is no incentive for anyone to build more than the bare minimum transmission. This means that operation costs will always be higher than optimal for consumers and that construction will never take a forward looking approach to keep long-term costs down.

6. PJM's system of making the largest bid the price paid by all buyers at a given time rather than adding up the cost of all bids as was done in the past, automatically makes our market prices high. This is a systemic design that hurts consumers. It should be changed.

7. To counter concerns about Virginia's lack of influence over the operation of transmission once our utilities transferred control to PJM, PJM pointed out that the state had an ex-officio position on the Reliability, Electric Markets, and Member's Committees. (December 10, 2004 presentation to the CEUR Consumer Advisory Board). So far, Virginia has declined to place an individual in a position of regularly following and participating in proceedings at PJM, preferring to pay for consultants if there are major issues. This means that Virginia depends upon PJM and our utility members of PJM to notify us if there are issues. It means that there is no party with the public interest, as well as no party with a consumer interest, regularly following and participating in PJM decisions. Virginia should have at least a public interest, if not a funded consumer interest, individual regularly participating in PJM every available way. To date, we have essentially totally given up any influence there to balance the industry interest.

8. Currently, Virginia's investor owned utilities have extremely strong influence over our elected officials at all levels and over the Commission. We have found that decision makers are extremely hesitant to take action that would displease Dominion, in particular. It means that they are unable to impartially represent the public interest. Consumer voices are few and are habitually allowed extremely limited opportunities to participate in the discussion or the decision making process whether in the legislative realm or in other meetings. For example, none of the typical consumer participants were even invited to the recent PJM Virginia Summit. Some view the situation as being not unlike that of the railroads a century ago. The Commission may not be in a position to fully evaluate the situation, but the commonwealth is in an extremely unbalanced posture.

9. There has been no public or widespread discussion of how this restructuring affects the security of Virginia's electric power in our post 9-11 world. It seems that the more highly interconnected system will be more vulnerable to damage by terrorists. This is an issue that should be addressed.

10. There should be a cost-benefit study of the restructured system with the traditional rate-of-return system. Today the restructured electric market has new or higher costs for a Regional Transmission Organization (PJM), trading power, tools like hedging, and growing transmission costs. Instead of spending money on lawyers and experts for proceedings before the State Corporation Commission, utilities spend increasing sums donating to and lobbying legislators and others. It appears that there are more new and increased costs than savings in the restructured system.

11. The legislature should investigate further restructuring of the electric market so that a more reasonable balance exists between the industry and consumers. The public interest is not being served by the current situation. Only utilities are benefiting. Consumers and communities are being harmed.

    Since Virginia is now one of only three states with electric rates traditionally below the national average still involved in "deregulation" of the electric market, and since we have only given away control of our transmission system, it is time to actively investigate other alternatives for restructuring. Of our geographic neighbors, only DC and Maryland have restructured their electric markets. Under rate-of-return regulation, our neighboring states provide businesses and consumers that locate in their states better options than those currently available in Virginia. The future economic stability and sustainability of our families and our communities depends upon a more balanced solution than the current one. VCCC would welcome the opportunity to participate in a process to design and implement such a solution.

Irene E. Leech, Ph.D.
President
Virginia Citizens Consumer Council
4220 North Fork Road
Elliston, VA 24087
540 230 5373 (cell)
ileech@vt.edu

Louis R. Monacell, Esq.
Phone: 804-697-4120
804.697.4135
Fax: 804-697-6120
E-mail: lmonacell@cblaw.com

Edward L. Petrini, Esq.
Phone:

Fax: 804.697.6395
E-mail: epetrini@cblaw.com

May 22, 2006

David M. Eichenlaub
Division of Economics and Finance
State Corporation Commission
1300 East Main Street
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 April 7, 2006, 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 ("Virginia Power") and Appalachian Power Company ("Appalachian Power"), respectively.

I. Report Card

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. It reveals low or failing grades on the degree of retail competition and 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 plants are worth more or less than book value), and the entry of independent power producers. We are unaware of reliability problems, so we have given transmission and distribution reliability our only "A" grade. The only "B" grade is utility earnings. Functioning of a regional transmission entity earned a "C" grade after Virginia Power and Appalachian Power finally joined the PJM Interconnection LLC, four years after the original statutory deadline.

II. Committees' Concerns with Electric Restructuring

[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.

Electric restructuring in Virginia, raises serious concerns, which can be summarized as follows:

- Customers of both Virginia Power and Appalachian Power will soon face significant, unwarranted rate increases based on an unfair, lopsided process.

- Commencing after 2010, when so-called "capped rates" end, customers of both utilities may face *extraordinary* rate increases, of perhaps 100% or more, that would unfairly enrich both utilities with no corresponding benefit to consumers. After 2010, customers of both utilities are scheduled to pay "market prices" for electricity supply. States north of Virginia, and, indeed, portions of Virginia itself now are grappling with crushing rate burdens resulting from going to "market" prices for electric supplies.

We discuss these concerns in greater detail below. In connection with the near term increases, we first discuss those related to Virginia Power and then those related to Appalachian Power. The concerns regarding near-term increases arise primarily from fundamentally unfair provisions in the Restructuring Act that (i) prohibit the Commission from initiating base rate decreases even if utilities' costs and revenues would warrant such decreases, and (ii) require the Commission to grant rate increases but ignore utilities' costs and revenues that would mitigate or eliminate the need for such increases. We discuss these concerns below in connection with both Virginia Power's and Appalachian's near term rate increases. We also discuss below the exorbitant future rate increases that may result from imposition of market prices on customers of both utilities upon the expiration of "capped rates."

A. Virginia Power's Near Term Rate Increase

Virginia Power's current "base" (or non-fuel) rates were established in a rate case decided by the Commission in 1998. The Restructuring Act, enacted on July 1, 1999, essentially "froze" those base rates.

The Restructuring Act permits utilities to recover certain "stranded costs" through their rates. With customers given the opportunity to choose a supplier other than their local utility, it was claimed at the time of enactment that utilities might be unable to recover costs incurred under the pre-existing regulatory regime.

The Commission Staff's most recent review of Virginia Power's level of profits and rates shows that Virginia Power accumulated more than $1.2 billion "available for stranded cost" recovery from 1998 through 2003.[12] Only a miniscule number of Virginia Power's customers, however, have elected to obtain service from a supplier other than Virginia Power. Thus, while it has not experienced its first dollar of "stranded cost," Virginia Power accumulated more than a billion dollars toward "stranded cost" recovery as of the time of completion of the most recent Commission Staff review of its finances. Further, the same Commission Staff report shows that Virginia Power's base, or non-fuel, rates are excessive by about $400 million per year, or about 10% of total rates.[13]

While Virginia Power accumulated such significant amounts for what turned out to be non-existent "stranded costs," its fuel factor rose steadily. From 1998 through 2003, Virginia Power's fuel factor increased from 1.152 cents/kWh to 1.613 cents/kWh.[14] Because charges imposed by Virginia Power through its fuel factor account for a disproportionately large portion of the total bill of its large industrial customers, significant increases in the fuel factor adversely affected large industrial customers. (Virginia Power's current fuel factor accounts for approximately 40% of the total bills of its large industrial customers.)

In December 2003, the Commission issued an order establishing a new fuel factor of 1.891 cents/kWh for Virginia Power to take effect on January 1, 2004. A few months later, in the 2004 Session, the General Assembly amended the fuel factor provisions of the Virginia Code, among other things, by freezing that fuel factor through June 30, 2007. The General Assembly's amendment further required that, prior to that date, the Commission would establish another fuel factor tariff to take effect on July 1, 2007 and remain in effect through December 31, 2010. (The 2004 amendment to the fuel factor provisions of the Code prohibited the Commission from increasing Virginia Power's fuel factor to permit collection of fuel costs not recovered through the current fuel factor or decreasing the fuel factor to credit customers for any over-recovery of fuel costs through the current fuel factor. In the 2006 Session, the General Assembly adopted an amendment to the fuel factor provisions of the Virginia Code that requires the Commission to set annual fuel factors, commencing July 1, 2007, and requires such fuel factors to be

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[12] The Commission Staff reviews annual financial data filed by Virginia Power and other electric utilities. The Staff completed its most recent report concerning Virginia Power's financial data on October 15, 2005. That report covers data for the year 2003.

[13] Virginia Power has filed its Annual Informational Filings for 2004 and 2005; however, the Commission Staff has not yet completed its review of those filings.

[14] Virginia Power's fuel factor was 1.050 cents/kWh from May 1998 to December 1998; 1.152 cents/kWh from December 1998 through January 2000; 1.339 cents/kWh from February 2000 through December 2000; and 1.613 cents/kWh from January 1, 2001 through December 31, 2003.

'trued up' for under- or over- recoveries incurred by Virginia Power subsequent to that date. Thus, the fuel factor that takes effect on July 1, 2007, will remain in effect for one year and be subject to adjustment, starting July 1, 2008, for under- or over-recovery of fuel costs from July 1, 2007.)

Since 2004, Virginia Power's fuel costs have risen substantially, and its current fuel factor has not produced sufficient revenues to recover such costs. However, the over-recovery of its non-fuel costs in its base rates, discussed above, will likely offset the under-recovery of its fuel costs.

Virginia Power's customers now face a potentially *significant* fuel rate increase on July 1, 2007. Because projected fuel costs are higher than the level of such costs included in the calculation of its current fuel factor, Virginia Power may request an increase in its fuel factor of as much as 50% or more, which could increase customers' bills by as much as 20% or more. While the 2006 amendment to the fuel factor provisions of the Code, § 56-249.6, permit the Commission to defer for later recovery up to 40% of such increase, thereby smoothing the effect of any rate "shock" that otherwise might occur on that date, deferral of the recovery of such costs in the fuel factor merely means paying them later.

Any such increase in fuel costs, moreover, cannot, under current law, be offset by a corresponding decrease in Virginia Power's non-fuel, or base, rates because the Restructuring Act essentially freezes its base rates. Thus, even though its base rates remain essentially frozen by law at an excessive level (according to the Commission Staff's most recent analysis), Virginia Power may be able to increase its fuel factor significantly and continue to collect deferred amounts through 2010. It can continue to enjoy the benefit of the excess revenues collected through its base rates while also increasing its fuel factor to collect increases in its fuel costs. Large industrial customers, whose bills are significantly affected by changes in the fuel factor, will be especially disadvantaged. Their fuel factor may increase significantly with no offsetting decrease in base rates.

In sum, Virginia Power's customers, including its large industrial customers, face a potentially significant, unnecessary, and unwarranted rate increase on July 1, 2007.

B. Appalachian Power's Near Term Rate Increases

Appalachian Power's current base rates were established in a rate case decided in 1999. Since that time, Appalachian's base rates have not produced excess revenues to the extent of those produced by Virginia Power's base rates. In fact, the Commission Staff's most recent report on Appalachian Power's level of profits and rates, dated April 27, 2005, shows that, based on 2004 data, Appalachian's current rates under-collect its costs by more than $49 million per year. (This contrasts with the Commission Staff's report for the prior year, 2003, which found a revenue excess of $9.7 million per year.)

The Restructuring Act prohibits the Commission, whether on its own initiative or in response to a complaint by customers or any customer representatives, such as the Division of Consumer Counsel of the Attorney General's Office, from reducing Appalachian's base rates, so the Commission was not able, as a result of the findings in the Staff's report for 2003, to initiate a proceeding to determine whether Appalachian's rates should be reduced. This prohibition contrasts with the provision in the Restructuring Act permitting the Commission to "adjust" Appalachian's "capped rates" to reflect changes in the cost of fuel. Pursuant to that provision, the Commission recently increased Appalachian's fuel factor by 3.65 mills/kWh, effective January 1, 2006. This increase in the fuel factor resulted in an increase in the bills of Appalachian's large industrial customers of more than 10%; however, due to the prohibition in the Act against Commission-initiated base rate changes, the Commission could not even consider changes in Appalachian's base rates that might have been warranted and that might have had the effect of offsetting the fuel factor increase.

The prohibition against Commission-initiated base rate changes also contrasts with the requirement for the Commission to "adjust" Appalachian's base rates for certain specified categories of costs *known to be increasing*, regardless of whether all of its other costs and revenues warrant any change in rates. One of the 2004 amendments to the Restructuring Act *requires* the Commission to "adjust" Appalachian's so-called "capped rates" not more frequently than once every 12 months for incremental environmental compliance and transmission and distribution reliability costs ("E&R" costs) prudently incurred on and after July 1, 2004. Thus, pursuant to the Restructuring Act, the Commission must "adjust" Appalachian's "base," or non-fuel, rates, for E&R costs, which are known to be increasing, but the Commission is prohibited from considering all of Appalachian's non-fuel costs and revenues and modifying Appalachian's rates accordingly. On July 1, 2005, Appalachian Power filed an application with the Commission to increase its "capped rates" for E&R costs. As modified by Appalachian during the case, the application seeks an average annual increase of 3.06%. The request is currently pending before the Commission.

Moreover, unlike the provisions in the Restructuring Act applicable to Virginia Power, the Act's provisions relating to Appalachian permit it to seek, prior to July 1, 2007, a change in its base rates based on a traditional rate case in which all of its costs and revenues are considered. Appalachian recently has filed with the Commission an application for an average annual increase of about 25%. Thus, due to the prohibition against Commission-initiated rate changes, the Commission has not been able to order any rate reduction that otherwise might have resulted from excess base rates, but now Appalachian's customers may face a significant base rate *increase*, instituted by Appalachian, and any such increase may be over and above both the recent (and any future) fuel rate increases and any annual E&R base rate increases resulting from currently pending, and subsequent, E&R rate cases.

In sum, the Restructuring Act causes unfair and unreasonable rates that disadvantage Appalachian's customers. The Act prohibits the Commission from initiating a case to reduce Appalachian's rates when they produce excess revenues, but it has permitted rate increases. Appalachian has increased its fuel factor, and now it is poised to increase its base rates, both in its recently filed general rate case and in its pending and future "E&R" cases.

C. Future Exorbitant Rate Increases from Market Prices for Customers of Virginia Power and Appalachian Power

Beyond the Committees' concerns about the unfair and lopsided law that permits selective rate increases (but not rate decreases) for Virginia Power and Appalachian Power, the Committees are deeply concerned about the prospect of extraordinarily large rate increases resulting from market-based pricing after expiration of the current, "capped rates."

Pursuant to the Restructuring Act, "capped rates" are scheduled to expire on December 31, 2010. Rates for generation and related services will be based on the Commission's determination of market prices after that date. While no one can predict with certainty prevailing market prices for such services at that time, the current difference between market prices and the "capped rates" of Virginia Power and Appalachian Power suggests that going to market-based prices could be devastating for consumers, including large industrial consumers. Presently, large industrial customers of Virginia Power pay about 4.5 cents/kWh, on average, while large industrial customers of Appalachian pay about 3.5 cents/kWh. In contrast, market prices in the PJM region have caused utilities' retail rates to customers in Maryland and Delaware, where capped rates have ended, or are about to end, to exceed 10¢/kWh. This would represent an increase of 100% to almost 200% in bills to some industrial customers of Virginia's two largest utilities.

Moreover, as the Commission's most recent annual report to the Commission on Electric Utility Restructuring ("Restructuring Commission") has emphasized, the poorly functioning wholesale market -- which, after December 31, 2010, would drive prices for Virginia Power's and Appalachian's retail customers – does not bode well for customers of those utilities. Trends and features in the wholesale market, as stated in that report, include the following:

- the so-called "single price auction" (where the price in wholesale spot market is set by the offer price of the last unit required to meet load, not by the average cost of power from a diverse fleet of generating resources, as is the case under cost of service regulation by the Commission);
- an increasing tendency toward oligopoly as a result of mergers in the power generation sector;
- new capacity pricing constructs, or relaxed market mitigation, which may result in additional cash flow to the generation sector; and
- challenges related to market monitoring and related concerns about the exercise of market power.

In sum, the expiration of so-called "capped rates" in 2011 could result in massive rate increases for customers of Virginia Power and Appalachian Power, and in related adverse impacts on Virginia's homes, businesses and economic development, as compared to other states, such as North Carolina, which have not restructured their electric industry.

The Restructuring Commission is, of course, launching a two-year study of the impact of the expiration of the "capped rates," but it need look no farther than to states north of Virginia to glimpse the future. Here are only a couple examples:

- In Maryland, in the face of the ending of capped rates and being forced to market prices, Alcoa shut down an aluminum smelter with 600 jobs lost. That state's largest utility, Baltimore Gas and Electric ("BG&E"), will go to market rates in July. The Maryland Public Service Commission, which has estimated that a typical residential customer would be hit with rate increases of 72%, has proposed to "phase in" the rate increase, thus reducing the impact of the increase in July. Participants in the "phase-in" plan, however, still would be required to pay BG&E the entire amount of the increase that is deferred for later payment. Merely "phasing in" massive rate increases mitigates their immediate impact but, because customers ultimately must pay the massive, deferred costs, obviously does not represent a solution to the increase itself.

- In Delaware, Delmarva Power announced in February that it would raise its residential rates by approximately 59% on May 1, when rate caps expired in that state. Delmarva Power's rates for large commercial and industrial customers were to increase even more. The General Assembly enacted a "phase-in" plan to help customers defer, but not avoid, the rate increases unless customers elected to "opt-out" of the plan, in which case they would pay the entire increase commencing May 1.

Beyond such current experiences in nearby states, the Restructuring Commission need not look beyond Virginia's own borders to appreciate the impact of going to market prices. Delmarva has filed an application with the Commission seeking an average rate increase of 50% in its Virginia territory (as much as 65.3% for certain large commercial and industrial customers) as a result of going to market-based rates, and the Commission's annual report to the Restructuring Commission, cited above, describes the "rate shock" of customers of some Virginia electric utilities (Craig Botetourt Electric Cooperative, City of Danville Municipal, City of Bristol Municipal) resulting from large price increases necessitated by exposure to current and expected future wholesale market conditions.

Conclusion

We hope you will take the Committees' concerns into account as you continue to study and assess public policy in this area, and we appreciate the opportunity to share those concerns with you. 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 recent developments do not bode well for its future success.

Sincerely,

Louis R. Monacell　　　　Edward L. Petrini

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	F	Present market prices and trends suggest that retail customers of Appalachian Power Company ("APCo") and Dominion Virginia Power ("DVP") have few or no prospects for savings from retail competition in view of the fact that market prices now greatly exceed the regulated generation costs of APCo and DVP.
Customers rates during the transition to competition	D	The State Corporation Commission ("SCC") Staff's most recent report on DVP's earnings and indicates that its rates are excessive by 10% and would be reduced by approximately $400 million per year if reset based on cost of service. DVP's rates have soared since the Act passed in 1999 due to rate "adjustments" to reflect increased fuel costs. Legislation enacted in 2004 froze DVP's 2004 fuel factor through June 2007. As a result, customers now are paying a lower fuel factor than otherwise would have been the case. DVP's fuel factor is likely to rise again significantly on July 1, 2007, when the SCC re-sets it. The SCC, however, still cannot offset the increase by considering DVP's base (non-fuel) rates. The SCC most recent report on APCo's earnings indicates an annual "revenue deficiency" of about 5.2%. This month, APCo applied to the SCC for a general base rate increase. It stated that the increase, if granted, would increase rates approximately $198 million, or about 25% on average. Based on SCC Staff's most recent financial review and the rate application, it appears that APCo's rates are collecting revenues below its costs. The 2004 amendments to the Act, on the other hand, encourage unfair, single-issue rate increases for APCo without permitting the SCC to review the total cost of service to determine whether cost reductions or revenue increases would offset such increases.

Utility earnings	B	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 2004 or 2005 annual informational filings ("AIFs"); however, the 13.26% rate of return exceeds the 9.10% to 10.10% rate of return found reasonable in the SCC Staff's review of DVP's 2003 annual report, the most recent AIF reviewed by the SCC Staff. While APCo's Virginia electric business appears to have produced modest over-earnings during 2003, APCo's earnings -- as indicated in the recent SCC Staff report on its 2004 AIF and in APCo's most recent general base rate increase application, discussed above -- appear to be falling below a reasonable range.
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.
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.
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	A	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 was completed and no serious deficiencies were shown. We are not aware of an independent, in-depth review of transmission and distribution reliability. In the absence of such a review, we must assume that normal measures of performance are being met. We remain cautious, nevertheless, about the effect of restructuring on transmission and distribution reliability in view of the factors cited by the SCC Staff as well as the significant reductions in employees reported by DVP to the SCC Staff during its post-Isabel audit. Employees in the "transmission" category declined by 61%, for example, during the period 2000 through 2004, while employees in the "distribution" category declined 23.34%.

Louis R. Monacell, Esq.
Phone: 804-697-4120
804.697.4135
Fax: 804-697-6120
E-mail: lmonacell@cblaw.com

Edward L. Petrini, Esq.
Phone:

Fax: 804.697.6395
E-mail: epetrini@cblaw.com

CHRISTIAN | BARTON, LLP
Attorneys At Law

June 12, 2006

David M. Eichenlaub
Division of Economics and Finance
State Corporation Commission
1300 East Main Street
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 the opportunity to offer the following comments in response to those of other interested persons. 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 ("Virginia Power") and Appalachian Power Company ("Appalachian Power"), respectively.

The Committees' initial comments expressed serious concerns about electric restructuring in Virginia. Such concerns include the fact that customers of both Virginia Power and Appalachian Power will soon face significant, unwarranted rate increases based on an unfair, lopsided process; and, commencing after 2010, when so-called "capped rates" end, customers of both utilities may face extraordinary rate increases, of perhaps 100% or more, that would unfairly enrich both utilities with no corresponding benefit to consumers. The Committees' comments emphasized that states north of Virginia, and, indeed, portions of Virginia itself now are grappling with crushing rate burdens resulting from going to "market" prices for electric supplies. Virginia Power filed comments that largely ignored these concerns, but they address other matters that warrant this brief response.

Claimed Customer Benefits

Virginia Power asserts that restructuring "has produced significant benefits for the Commonwealth's customers." Virginia Power cites "hundreds of millions of dollars" in customer savings resulting from the fuel factor freeze enacted by the General Assembly in 2004. Virginia Power's comments, however, ignore the "hundreds of millions of dollars" in excess revenues that the base, or non-fuel, portion of its "capped rates" has generated and may continue to generate through 2010. As indicated in the Committees' initial comments, Virginia Power had accumulated, according to the Commission Staff's most recent report concerning Virginia Power's earnings (for the year 2003), more than \$1.2 billion in earnings available for stranded cost recovery during the 1998 – 2003 period. Virginia Power, however, has yet to incur its first dollar of "stranded costs." The excessive base rates that have produced such excess earnings – rates estimated to be excessive by about \$400 million per year for the most recent periods (2002 and 2003) analyzed by the Staff -- are scheduled to remain in effect through 2010. Thus, while the fuel factor freeze, considered alone, has produced since 2004

some customer savings, the Restructuring Act's non-fuel (base) rate provisions have produced significantly excessive non-fuel rates. The adverse impact of the excess base rates on customers may exceed, by a substantial margin, the savings from the fuel rate freeze. Moreover, as Virginia Power's comments acknowledge, the fuel factor freeze is scheduled to end on July 1, 2007, when its fuel factor will be re-set, so any customer savings resulting from the freeze will terminate as of that date. Virginia Power's base rates, however, will not change on that date. Customers, therefore, are scheduled to continue to pay the same base rates that have produced such excessive earnings through 2010.

Virginia Power also claims that consumers have benefited from the "capped rates" on the basis of a study performed in 2002, and later updated in 2004, by Chmura Economics & Analytics ("Chmura"), a Richmond economic consulting firm. Virginia Power hired Chmura to study the impact of "capped rates" on residential utility consumers during the period in which "capped rates" will be in effect. Virginia Power states in its comments that the 2004 study projects residential customer savings of "as much as $1.8 billion through 2010" and "annual savings" for a typical residential customer of "up to $74" during the "capped rate" period.

The Chmura study, however, is based on a macro-economic forecasting model, not Virginia Power's costs. Thus, it ignores the most basic fact of ratemaking: that the Commission sets rates to cover operating costs plus a reasonable return on the utility's investment in assets that provide customers with service. While Virginia Power's cost data during the "capped rate" period, both actual and projected, presumably could have been made available to its own consultant, its consultant proceeded without it. Instead of analyzing Virginia Power's costs in order to determine what its rates would have been if the General Assembly had not enacted the "capped rates," the study estimates what Virginia Power's rates would have been on the basis of factors, such as national employment rates and short-term national interest rates, that have never been the basis for setting Virginia Power's regulated revenue requirement.

The Chmura study's findings, moreover, have been contradicted by detailed annual analyses of Virginia Power's costs and revenues conducted by the Commission Staff. As indicated above, the most recent of those analyses available, which follow the approach used by the Commission in setting rates, show that Virginia Power's "capped rates" have produced revenues significantly in excess of its costs – that is, significantly in excess of the costs that would have been used for ratemaking purposes if its "capped rates" had not been in effect.

Finally, Virginia Power asserts that restructuring "savings" have not been confined to Virginia, and it cites, in particular, studies by two consulting firms, Cambridge Energy Research Associates ("CERA") and Global Energy Decisions, which purport to show significant customers savings nationwide and in the Eastern Interconnect, respectively. As the comments of the Old Dominion Electric Cooperative detail, however, **both** ***studies contain significant flaws. For example, most of the claimed $34 billion in consumer savings found by the CERA study are ascribed to the southern states, which have experienced little restructuring.***

Rate Increases in Non-Restructured States

Virginia Power also contends that rates have increased in non-restructured states, and it cites as examples significant rate increases for utilities in Wisconsin, Oklahoma, and Florida. The Commission and the General Assembly, however, should not be misled by such cases. No one suggests that traditional, cost-based regulation "immune[izes]" customers from legitimate, cost-based rate increases related to a utility's specific circumstances. Thus, customers served

by a utility that is heavily dependent upon natural gas, like Public Service Company of Oklahoma (Generation owned by that utility is 74% gas-fired.), will doubtless experience significant rate increases if natural gas prices triple; customers of a utility like Florida Power and Light, which also is heavily dependent upon natural gas-fired generation and which just experienced significant damage due to several massive hurricanes, can expect significant, cost-based rate increases; and customers of utilities in the midst of constructing base load generation (and experiencing increases in fuel and other costs), such as the customers of Wisconsin Public Service Corporation, can expect significant rate increases. Virginia Power's generation fleet, however, is not heavily dependent upon natural gas; its service territory has not experienced anything approaching the level of hurricane-inflicted damage visited upon Florida's utilities; and it is not constructing any new base load generation.

While Virginia Power refers to utilities different from it in important respects as examples of utilities experiencing significant rate increases under traditional regulation, it might have elected to cite an example of such regulation closer to home. North Carolina has not restructured. Virginia Power's North Carolina operations, therefore, are subject to traditional rate regulation in that state. Thus, under North Carolina law, the North Carolina Utilities Commission ("NCUC") may initiate a rate case and, if it finds that a utility's rates are excessive, order a rate reduction. Last year, following such an NCUC-initiated investigation, Virginia Power agreed to a base rate **reduction** ***of $12 million per year for its North Carolina operations. In contrast, as the Committees' initial comments point out, Virginia's Restructuring Act prohibits the Commission from reducing Virginia Power's base rates.***

Increased "Shopping" Elsewhere

Virginia Power cites "fairly vigorous" shopping in several other jurisdictions, especially among larger industrial and commercial users. For example, Virginia Power cites March 2006 data from the Maryland Public Service Commission indicating that competitive providers served 80% of large commercial and industrial accounts. The comments of Constellation Energy make a similar point about high shopping rates among such customers in Maryland.

No one doubts that the expiration of "price caps" in other jurisdictions, and the implementation of market-based rates for large customers, has resulted in increased shopping by large commercial and industrial customers. Obviously, where large users are forced to face significant rate increases (ranging up to 118% in Delaware, for example), as a result of going to market-based default service rates, many large users can be expected to shop to take service from alternative suppliers.

The Committees are concerned, however, about the potentially *extraordinary* rate increases that may result from going to market rates in Virginia and the resulting *windfalls* for Appalachian Power and Virginia Power at their customers' expense. Such "shopping" does not deliver customer benefits if market-based rates are greatly in excess of cost-based, regulated rates for Appalachian Power and Virginia Power. On the contrary, it merely produces unfair and unnecessarily negative economic consequences for millions of customers, including large industrial and commercial customers. The potential for such consequences does not bode well for Virginia's economic future, including the future of jobs in Virginia's manufacturing sector.

Conclusion

We appreciate the opportunity to comment on restructuring issues, and, again, we hope you will take the Committees' concerns into account as you continue to study and assess public policy in this area

Sincerely,

Louis R. Monacell

Edward L. Petrini

#764885