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, 2004

COMMONWEALTH OF VIRGINIA

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STATE CORPORATION COMMISSION
DIVISION OF ECONOMICS AND FINANCE

August 31, 2004

Dear Reader:

As directed by §56-596 B of the Virginia Electric Utility Restructuring Act, the State Corporation Commission will issue its fourth annual report to the Governor and the Commission on Electric Utility Restructuring ("EURC") on September 1, 2004.

Subsequent to the printing of this report to meet the September 1, 2004 deadline, the State Corporation Commission issued its Order Granting Approval to AEP-VA to transfer functional and operational control of its transmission facilities to PJM in Case No. PUE-2000-00550. The Order was issued on August 30, 2004.

This information thus updates the discussion regarding Case No. PUE-2000-00550 on page 40 of Part II of the SCC's annual report. Additional details concerning the referenced Order may be found on the Commission's web site at: http://docket.scc.state.va.us:8080/vaprod/main.asp .

Sincerely,

David R. Eichenlaub
for Howard M. Spinner

THEODORE V. MORRISON, JR.
CHAIRMAN

CLINTON MILLER
COMMISSIONER

MARK C. CHRISTIE
COMMISSIONER

COMMONWEALTH OF VIRGINIA

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

STATE CORPORATION COMMISSION

September 1, 2004

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

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

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

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

Respectfully submitted,

Theodore V. Morrison, Jr.
Commission Chairman

Clinton Miller
Commissioner

Mark C. Christie
Commissioner

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Executive Summary and Overview

It has been over five years since the Virginia General Assembly passed the Virginia Electric Utility Restructuring Act[1] ("the Act"); less than three years remain until the mid-2007 end of the transition period set forth in the Act. Section 56-596 of the Act requires the Virginia State Corporation Commission ("SCC") to report to the Commission on Electric Utility Restructuring ("CEUR") and the Governor by September 1 of each year on the status of competition in the Commonwealth, the status of the development of regional competitive markets and the SCC's recommendations to facilitate effective competition in the Commonwealth as soon as practicable. This section of the statute also requires the SCC to report any recommendations of actions to be taken by the General Assembly, electric utilities, suppliers, generators, distributors, and regional transmission entities that the SCC considers to be in the public interest.

The SCC offers this Report pursuant to the requirements of the Act consisting of three parts. Part I is a description of evolving regional retail and wholesale markets prepared by Dr. Kenneth Rose, Senior Fellow, Institute of Public Utilities at Michigan State University. Part II reports on the status of retail access and competition in the Commonwealth. Part III presents and discusses recommendations to facilitate effective competition in Virginia that were raised by stakeholders responding to an annual SCC solicitation of potential recommendations and actions by the SCC.

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

Dr. Rose's Part I also provides extensive descriptions of retail markets on a state-by-state basis. He reports that 16 states and the District of Columbia continue to allow retail access. Several states have decided to delay retail access, restrict retail access to only larger customers or otherwise curtailed their retail access efforts. Of the 17 jurisdictions that allow retail access, there is little, if any, effective retail competition for electric service in the residential and small commercial market.

On the basis of the extensive information submitted by Dr. Rose in Part I of this Report, the SCC concludes that, while retail access is widely available in many jurisdictions, vigorous retail competition has yet to develop. This national result, when combined with results obtained here in the Commonwealth as detailed in Part II of this Report, still causes serious concern regarding the ability of retail electric competition to

[1] Title 56, Chapter 23 of the Code of Virginia.

provide, at the present time, lower prices for Virginians than would have been charged under the traditional regulation of the industry.

Part II of the Report focuses on activities in Virginia related to retail access and resulting competition in the electricity market over the past year. It also reviews the SCC's efforts to develop a proper infrastructure to accommodate competition and to prepare Virginians for consumer choice for generation, as directed by the Act.

During the past year the SCC has continued to implement the Restructuring Act. At the present time, about 3.1 million electricity customers in Virginia have the right to choose an alternative supplier of electricity. Approximately 29,400 customers in the southwestern part of the Commonwealth exempted from the Act by legislation enacted by the General Assembly in 2003 and approximately 7,600 customers served by Powell Valley Electric Cooperative.

As we reported last year, the right to choose has not yet evolved into the ability to choose. While it is clear that the SCC, the utilities and the various stakeholders have effectively enabled almost universal retail access in Virginia, there is 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 less than 1,900 residential customers and 20 small commercial customers in northern Virginia with an environmentally-friendly "green" power offer. This service is more expensive than Dominion Virginia Power's price-to-compare. Again, as detailed in Part I, this lack of activity is not unique to the Commonwealth; in other states currently offering retail access, few customers have the option to purchase power at a price lower than their incumbent's price to compare.

Over the past twelve months, the SCC, aided by the incumbent utilities and interested stakeholders, continued to make strides in preparing the Commonwealth for the arrival of competition for the generation component of electric service. Work coordinated by the Staff has assisted the SCC to provide the foundation for retail access by examining many issues, including competitive metering, supplier billing, default service, energy infrastructure, and regional transmission organizations ("RTO"). The SCC appreciates the time and effort of the respondents that have contributed to Staff's efforts.

The SCC has issued orders or reports during the past year relating to issues such as competitive metering, supplier billing, market price/wires charge determination, regional transmission organizations, and pilot programs within Dominion Virginia Power's territory. Slow development of competitive activity and statewide budget constraints have caused the SCC to continue suspension of its consumer education efforts.

Part III of the Report includes discussion of recommendations and comments advanced by various stakeholders as a means of facilitating effective competition in the Commonwealth as soon as practicable as well as the Commission's activities to properly align processes and systems to foster effective competition.

As outlined in this Report, the problems that are impeding the development of retail competition in Virginia and other regional markets continue unabated. In terms of the existence of retail competition, little, if anything, has changed since last year. There still appears to be universal agreement that before a viable competitive retail market develops in the Commonwealth there must be a robust wholesale market and an operational and independent regional transmission organization. While much work has been done or is in the process of being done, it will take more time before that foundation becomes a reality. 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

ACC	Arizona Corporation Commission
AEI	American Energy Institute
AEP-VA	American Electric Power- Virginia
AP	Allegheny Power
BG&E	Baltimore Gas and Electric
BGS	basic generation service
BHE	Bangor Hydro-electric Company
CGV	Columbia Gas of Virginia
CMP	Central Maine Power Company
CSP	competitive service provider
CTC	competitive transition charge
DEDS	Dominion Energy Direct Sales
DEQ	Department of Environmental Quality
DVP	Dominion Virginia Power
ECN	Energy Cooperative of New York
EDI	electronic data interchange
ESCO	energy service company
FERC	Federal Energy Regulatory Commission
FREDI	First Regional Electronic Data Interchange
GISB	Gas Industry Standards Board
ICAP	installed capacity market of PJM
ICC	Illinois Commerce Commission
IEEE	Institute for Electrical and Electronic Engineers
KU	Kentucky Utilities
KW	kilowatt
LDC	local distribution company
LMP	locational marginal price
LTTF	Legislative Transition Task Force
MMU	Market Monitoring Unit of PJM
MPC	Montana Power Company
MPS	Maine Public Service Company
MPSC	Maryland Public Service Commission
MW	megawatt
NAESB	North American Energy Standards Board
NARUC	National Association of Regulatory Utility Commissioners
NEM	National Energy Marketers Association
NMPC	Niagra Mohawk Power Corporation
NOPEC	North East Ohio Public Energy Council
NOPR	Notice of proposed rulemaking
NOVEL	Northern Virginia Electric Cooperative
NU	Northeast Utilities
NYSEG	New York State Electric and Gas
O&R	Orange and Rockland

ODEC	Old Dominion Electric Cooperative
ODP	Old Dominion Power
PES	Pepco Energy Services
PE	Potomac Edison
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PMW	Power Markets Week
POLR	provider of last resort
PSE&G	Public Service Electric and Gas Company
PUCO	Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas
REC	Rappahannock Electric Cooperative
REP	retail electric provider
RG&E	Rochester Gas and Electric
ROA	retail open access
RTE	regional transmission entity
RTO	regional transmission organization
S&P	Standard & Poor's Ratings Service
SCC	State Corporation Commission
SERC	Southeastern Reliability Council
SOS	standard offer service
SPP	Southwest Power Pool
SWEPCO	Southwestern Electric Power Company
T&D	transmission and distribution
UBP	Uniform Business Practices
UHR	UHR Technologies
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
WGES	Washington Gas Energy Services
WGL	Washington Gas Light
WTU	West Texas Utilities

PART I

STATUS OF THE DEVELOPMENT OF REGIONAL COMPETITIVE MARKETS

2004 PERFORMANCE REVIEW OF ELECTRIC POWER MARKETS

2004 Performance Review of Electric Power Markets

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Review Conducted for the Virginia State Corporation Commission*

August 25, 2004

*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 author and do not necessarily reflect the views or opinions of the Virginia State Corporation Commission.

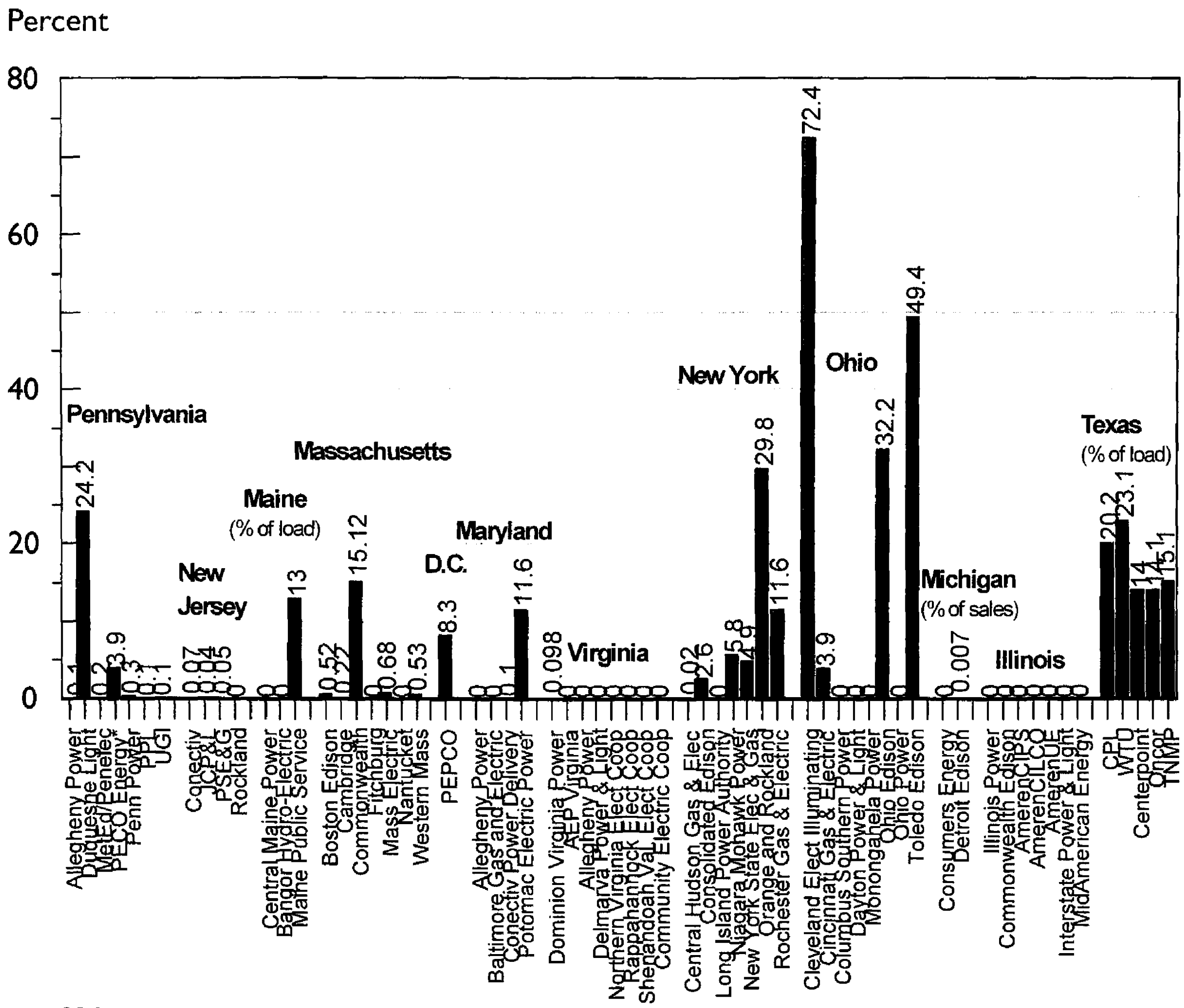
EXECUTIVE SUMMARY

Since the price run-ups in California and the West beginning in mid-2000 and into 2001, the electric supply industry has not been able to return to a relative stable or calm period of time. The industry's problems continued after the western power crisis with Enron's disclosures and collapse in late 2001, revelations of market price manipulation strategies, disclosures of accounting improprieties and data misreporting, the continuing "credit crunch," and, the major event of 2003, the most extensive blackout in North American history.

In the face of this turmoil, most states have decided to either discontinue their efforts to implement retail access or have stopped considering adopting it altogether. The overall picture of which states have adopted retail access has not changed substantially in the last few 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. Two states allow retail access for larger customers only; Nevada, that modified its original law to limit access to just larger customers and Oregon, whose original law limited retail access to larger customers. Six states that passed restructuring legislation later delayed, repealed, or indefinitely postponed implementation. Oklahoma and West Virginia passed restructuring legislation but stopped short of implementation, Arkansas and New Mexico have repealed their laws, California suspended the retail access program it already had implemented in September 2001, more than one year after the beginning of the California and western power crisis. Montana, has also been dealing with the severe aftermath of the western power crisis, has extended the transition period to retail access for smaller customers. They implemented retail access for large industrial customers in July 1998, but residential access originally scheduled to begin by July 2002 was postponed to 2027. While there are some large retail customers in western state retail markets active in the market (in California, Montana, and Oregon), in general, these retail markets have not yet fully recovered from the western power crisis.

Twenty six states are no longer considering restructuring at this time and none of these states appear to be near passage of restructuring legislation or working in any meaningful way toward passage at this time. In fact, no state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning to take shape. These states that did not pass legislation but were in the process of considering it either gradually lessened their efforts to allow time to consider what was occurring in the west or they abruptly stopped any activity that was ongoing at the time. A total of 32 states have repealed, delayed, suspended or are now no longer considering retail access.

For the 16 states and D.C. that have continued with retail access, many retail markets have remained relatively inactive, particularly for smaller residential customers. Figure ES.1 shows the percent of residential customers that are supplied by an alternative supplier to their local utility in 11 states and D.C. Of the 63 distribution companies represented in the figure, 43 or over two-thirds of the companies, had less than one percent of the customers choosing an alternative, most (27) were zero. Only seven have greater than 20 percent of the residential customers receiving power from alternative suppliers. Three of those seven distribution companies are in Ohio where nearly 95 percent of the residential switching in the state has been through the state's aggregation program. Two of the remaining four distribution companies were in relatively higher priced states, Pennsylvania and New York (although not the highest priced distribution companies in the state, each were the second highest priced distribution company in their state) and the two Texas distribution companies had the highest "price-to-beat" (the price-to-compare for residential customers) in the state.

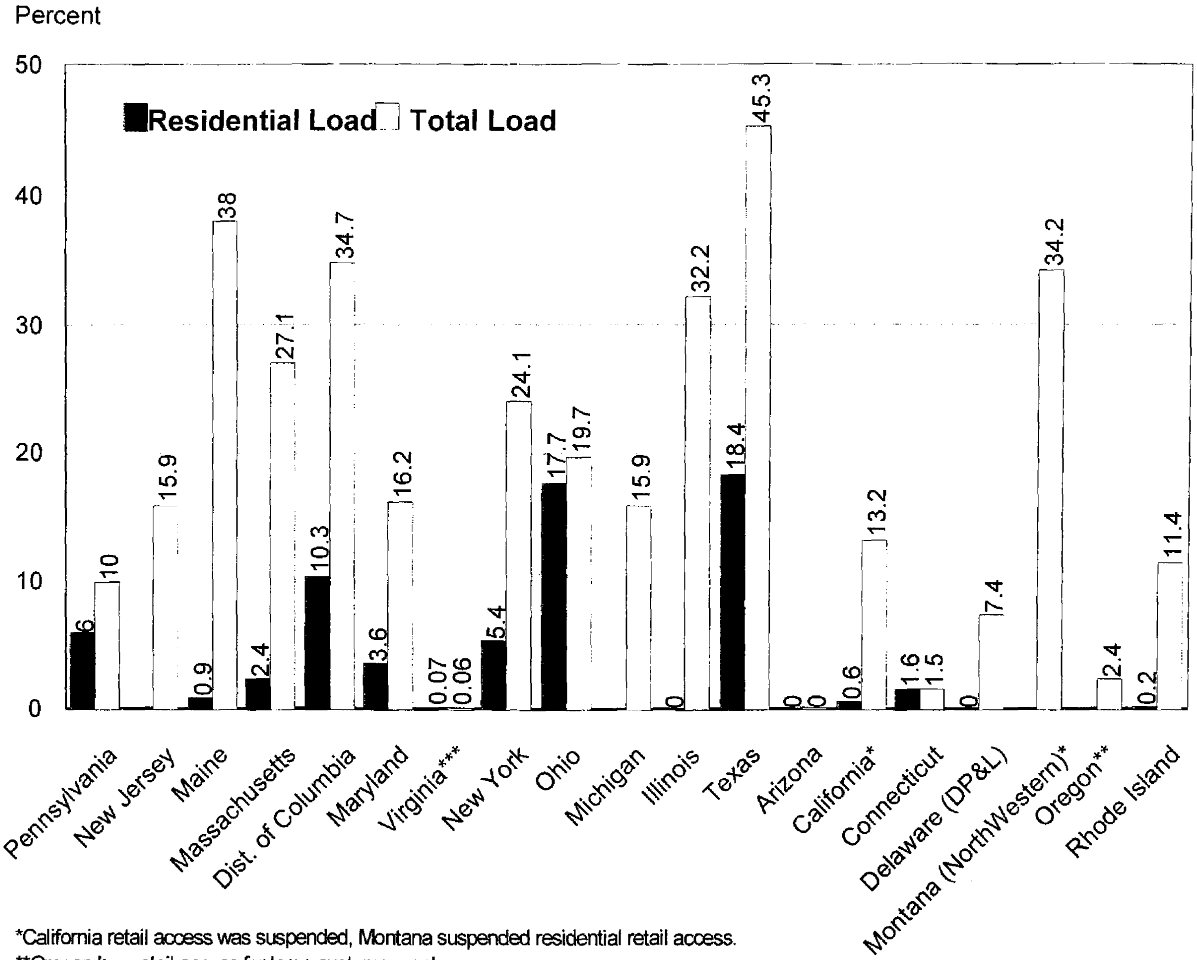


*PECO Energy percentage excludes assigned customers.

Data Sources: Various state agencies; Texas data from KEMA, Inc., "Retail Energy Foresight," June/July 2004.

Figure ES.1. Percent of residential customers switching to alternative suppliers, by distribution company.

Four of the five states with retail access for all customer groups that were not shown in Figure ES.1 are represented in Figure ES.2.[1] Figure ES.2 summarizes residential customer load and the state total customer load that have switched to an alternative supplier for 19 states and D.C. This figure shows the significant difference between residential customer migration to competitive suppliers and total state load



*California retail access was suspended, Montana suspended 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: Various state agencies and KEMA, Inc., "Retail Energy Foresight," June/July 2004.

Figure ES.2. Summary of residential and total state customer load served by alternative suppliers.

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[1]The two states not shown in either figures are New Hampshire, that reported a relatively low level of activity last year, and Nevada, which has retail access for large customers only, and (from state media accounts) had no customer switching from incumbent suppliers.

migration. This difference is due to the relatively greater market activity of the larger customer groups. While there are seven states where there are more than 20 percent of the total state load now being served by competitive suppliers, no state has reached that point for residential load. Only two states and D.C. have surpassed 10 percent of residential load, one of these states is Ohio, which again is mainly attributable to the state's aggregation program. Five of the seven states (including D.C.) where total load was greater than 20 percent were in relatively higher priced regions. The two exceptions were Texas, where again a substantial portion of the retail activity has been in the higher priced distribution companies of the state, and Montana, which began restructuring as one of the lowest-priced states in the country and where retail access is limited to only large customers. However, due to the western power crisis of 2000 and 2001, those customers that entered the power market paid considerably higher prices than they had before restructuring began.

Several states are now also using bidding or auctions to procure power supply for their non-choosing customers. The Maine Public Utilities Commission has conducted four rounds of competitive bidding since March 2000. Currently, all customers not receiving power from a competitive supplier are on competitively-determined standard offer price, this includes nearly all residential customers in the state. New Jersey has had three auction rounds of an Internet-based, simultaneous, multi-round, and descending clock auction. The "Basic Generation Service" load is auctioned simultaneously for all four New Jersey electric utilities. Maryland had its first round of competitive bidding for two distribution companies in 2004.

Wholesale markets and the transmission organizations that these markets often operate in, are continuing to evolve. The most extensive of these transmission regions are the three that operate in the northeastern U.S. in New England, New York, and the mid-Atlantic states. These areas have centralized spot power markets and independent transmission operation. Other parts of the country are developing similar structures, but did not begin with the same level of integration that the northeast regions began with and are still developing.

A common theme that most wholesale markets shared in the last two years is the substantial impact that the price of natural gas now has on power prices. In particular, the natural gas price spikes that occurred across the country in early 2003 and in the northeast region of the country in early 2004, led to corresponding power price spikes in these regions. Even when natural gas is not the most commonly used fuel to generate power in the region, because it is often the marginal fuel used and because many power contracts have the price for power pegged to natural gas prices, natural gas and power prices now generally move in tandem.

The most prominent industry event of 2003 was the August 14th blackout. This was the most extensive blackout in North American history, affecting an area of 50 million people and 61,800 MW of electric load in all or part of eight states and one

Canadian province. Estimates of the total cost in the U.S. range between $4 billion and $10 billion. Power was not restored for four days in some of the states and parts of Ontario had rolling blackouts for more than a week after. It is likely that this event will have a far reaching impact on the industry for the foreseeable future. A joint U.S. and Canadian Task Force was appointed to examined the cause of the blackout and make recommendations for improvements to avoid a reoccurrence. The Task Force's first recommendation was: "Make reliability standards mandatory and enforceable, with penalties for noncompliance." They state that "the single most important" recommendation they make is that "the U.S. Congress should enact the reliability provisions in H.R. 6 and S. 2095 to make compliance with reliability standards mandatory and enforceable." To date, this recommendation has not been met and is unlikely to happen until sometime during 2005 at the earliest.

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SECTION I
Overview of Electric Restructuring Activities and Issues in the U.S.

Introduction

Since the price run-ups in California and the West beginning in mid-2000 and into 2001, the electric supply industry has not been able to return to a relative stable or calm period of time. The industry's problems continued with Enron's disclosures and collapse in late 2001, revelations of market price manipulation strategies, disclosures of accounting improprieties and data misreporting, the continuing "credit crunch," and, the major event of 2003, the most extensive blackout in North American history.

In the face of this turmoil, most states have decided to either discontinue their efforts to implement retail access or have stopped considering adopting it altogether. For the 16 states and D.C. that have continued with retail access, many retail markets have remained relatively inactive, particularly for smaller residential customers. About two-thirds of the distribution companies had no or less than one percent residential customer migration from utility service. However, for some states, market activity for larger customers has been relatively stronger. Nine states had at least one distribution company with at least one non-residential customer category with 20 percent or greater of those customers buying power from an alternative supplier. Generally, these are in relatively higher priced distribution companies' territories. Several states are now also using bidding or auctions to procure power supply for their non-choosing customers. There is considerable variation, however, across states and even within a particular state on how retail markets have performed.

Wholesale markets and the transmission organizations that these markets often operate in, are continuing to evolve. The most extensive of these transmission regions are the three that operate in the northeastern U.S. in New England, New York, and the mid-Atlantic states. These areas have centralized spot power markets and independent transmission operation. Other parts of the country are developing similar structures, but did not begin with the same level of integration that the northeast regions began with and are still developing.

This Performance Review covers retail and wholesale market developments by region. The remainder of this section first provides an overview of state restructuring activities. Next, some recent important industry developments are summarized, including the continuing "credit crunch," generation capacity additions, the impact of higher natural gas prices, generation assets sales, the August 2003 blackout, transmission system investment, and an overview of regional transmission organization developments. This section then concludes with an explanation of how market performance is measured in both wholesale and retail markets. The next seven sections examine different regions of the country in terms of price and other factors to provide an indication on how the wholesale markets are performing in the regions. The regions examined here are the Mid-Atlantic, New England, New York, Midwest, Southeast, Texas, and the West. The state retail markets are investigated within each of the regional sections.

Summary of State Electric Restructuring Activities

Figure I.1 summarizes the current status of state retail access. Overall, the picture has not changed substantially in the last few years. Sixteen states and D.C. 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, that modified its original law to limit access to just larger customers and Oregon, whose original law limited retail access to larger customers. Six states that passed restructuring legislation later delayed, repealed, or indefinitely postponed implementation. Oklahoma and West Virginia passed restructuring legislation but stopped short of implementation, Arkansas and New Mexico have repealed their laws, California suspended the retail access program it already had implemented in September 2001, more than one year after the beginning of the California and western power crisis. Montana, has also been dealing with the severe aftermath of the western power crisis, has extended the transition period to retail access

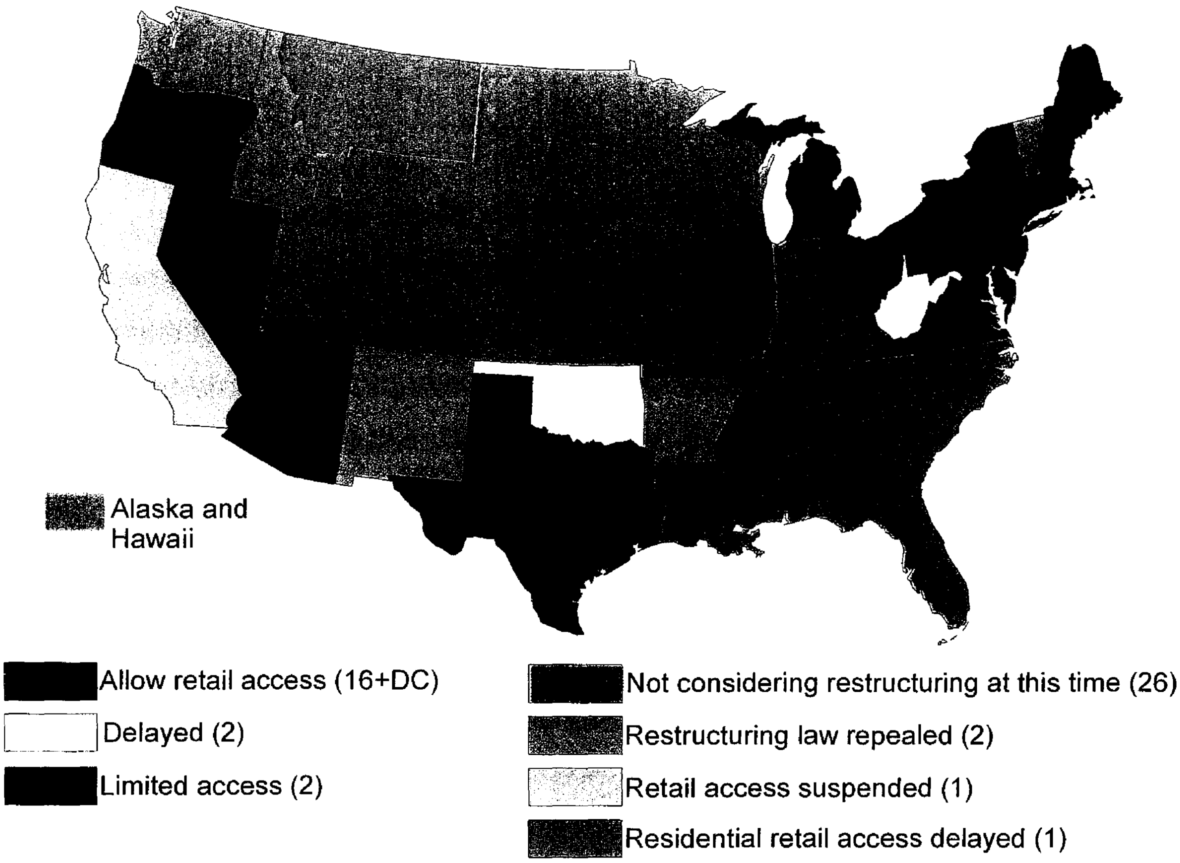

Figure I.1. Status of state retail access.

for smaller customers. They implemented retail access for large industrial customers in July 1998, but residential access originally scheduled to begin by July 2002 was postponed to 2027. While there are some large retail customers in western state retail markets active in the market (in California, Montana, and Oregon), in general, these retail markets have not yet fully recovered from the western power crisis.

Twenty six states are no longer considering restructuring at this time and none of these states appear to be near passage of restructuring legislation or working in any meaningful way toward passage at this time. In fact, no state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning to take shape. These states that did not pass legislation but were in the process of considering it either gradually lessened their efforts to allow time to consider what was occurring in the west or they abruptly stopped any activity that was ongoing at the time. A total of 32 states have repealed, delayed, suspended or are now no longer considering retail access.

Industry "Credit Crunch"

As documented in the last two year's Performance Reviews, the "credit crunch" has severely impacted the ability of power suppliers, especially competitive merchant suppliers, to raise capital and has forced companies to cut back on their energy trading operations, new plant investments, and fostered a "back-to-basics" strategies for many companies. Standard & Poor's (S&P) noted that the constrained access to capital was due to several investor concerns, including the accounting practices and disclosure, federal and state investigations, and investments outside the traditional regulated utility business, principally merchant generation facilities and related energy marketing and trading activities.[2] This ratings trend for the investor-owned utility industry (which include electric, gas, pipeline, and water companies) has continued since early 2000, and accelerated in the first quarter of 2003. S&P noted that there were "an unprecedented 50 downgrades among holding companies and operating subsidiaries, compared with just three upgrades during the first three months of 2003."

In early 2004, S&P noted a "reduced pace" of credit rating downgrades when compared to the previous two years. The number of rating changes on holding companies and operating subsidiaries dropped to 17 downgrades and two upgrades in the first quarter of 2004, from the 50 downgrades and three upgrades in the first quarter of 2003.[3] However, they note that the distribution of outlooks did not change much from 2003. The percentage of negative outlooks for utility sector companies increased slightly to 34 percent on March 31, 2004 from 31 percent in the first quarter of 2003.

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[2]Standard & Poor's, "Downside Rating Trend Continues For U.S. Utilities in First Quarter," April 24, 2003.

[3]Standard & Poor's, "Industry Report Card: U.S. Electric/Water/Gas," April 30, 2004.

S&P put positive outlooks at only about 2 percent. Echoing previous reports, S&P again made a distinction between companies that are primarily still vertically structured:

> Standard & Poor's expects that most companies whose core focus is on providing electricity and gas service will maintain financial profiles that warrant--at a minimum--investment-grade ratings. Prospectively, Standard & Poor's expects the traditional, nondiversified, and regulated U.S. investor-owned electric and gas industry to remain relatively stable, with little of the downward pressure experienced elsewhere in the energy industry.[4]

However, for those companies that are substantially involved in competitive activities:

> The outlook for the competitive segment of the industry continues to be largely negative. Merchant power generators are still facing many of the same issues that caused their widespread credit deterioration in 2002 and 2003. With natural gas prices remaining high and capacity overbuild expected to continue for the next several years, market conditions are not dramatically improving.[5]

S&P has noted that some companies are decreasing or discontinuing their investments in unregulated businesses, including merchant generation, energy trading, and international investments–strategies that were intended to help them deal with competitive markets and to enhance shareholder value. Another trend S&P has noted is the number of utility and power companies rated 'BBB' (companies considered to have an "adequate capacity to meet its financial commitments") and below has increased, while the number of firms rated 'A' and above has decreased ('A' rating is given to companies with a "strong capacity to meet its financial commitments"). However, they believe that credit ratings will stabilize at current levels.[6] In 2003, they noted that the large number of downgrades had caused the average rating for the U.S. power sector as a whole to slip into the mid-'BBB' area. They do not expect the industry

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[4]Standard & Poor's, April 30, 2004, p. 2.

[5]Standard & Poor's, April 30, 2004, p. 2.

[6]Standard & Poor's, "S&P Says U.S. Utilities and Power Industry Ratings Stabilizing," June 2, 2004.

to fall below that level and state that "companies that continue to emphasize a vertically integrated structure should hang onto an 'A-' average".[7]

Natural Gas Capacity and Natural Gas Prices

The continuing credit crunch, combined with weak market conditions in many regions for merchant power suppliers, has led to a significant cut back in investment in future generating capacity. As Figure I.2 shows, after a period of several years of the

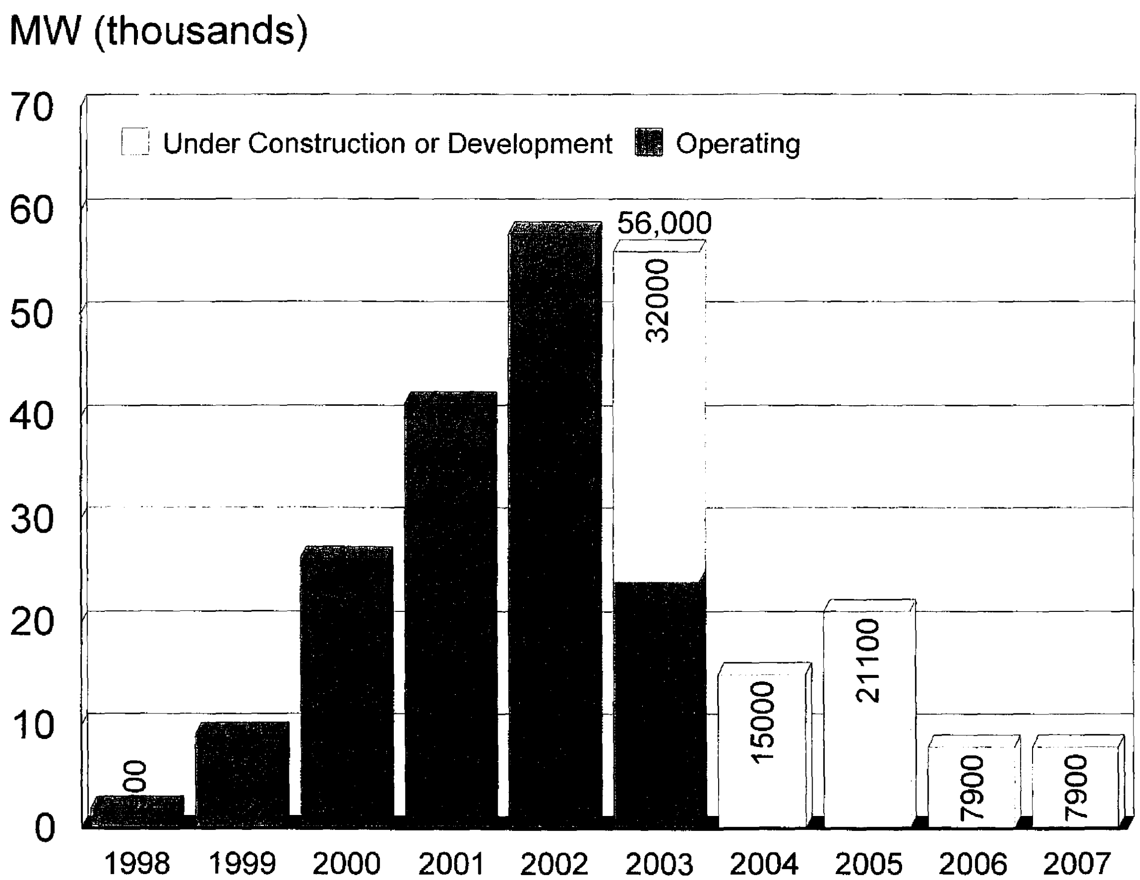

Figure I.2. Gas-fired turbine-based capacity additions in operation, 1998 to 2003, and capacity in development, 2003 to 2007.
Data Source: NERC Reliability Assessment 2003–2012, December 2003 (Energy Ventures Analysis, Inc. data).

[7]Standard & Poor's, "Downside Rating Trend Continues," April 24, 2003, p. 3.

largest capacity expansion in the industry in over half a century, the amount of capacity in the development stage or under construction has dropped substantially. In 2002, 57,800 MW of gas-fired capacity was added with more than 50,000 MW expected again for 2003.[8] This followed the 1999 through 2001 period when a total of 76,700 MW was added. The 1999 through 2002 additions are almost 15 percent of the industry's total net summer generating capacity in 2002. This compares with the period 1986 through 1998 when a total of 53,900 MW of gas-fired capacity was added for the entire period.[9] Coal capacity additions, in contrast, is expected to be only 12,800 MW between 2000 to 2009.[10] No new plants entered construction during the first quarter of 2003.

With these additions, natural gas-capable capacity accounted for about 37 percent of the total U.S. net summer capacity in 2002.[11] The increasing importance of natural gas as a fuel source for power generation added to the fact that natural gas is the marginal fuel in most regions of the country, have combined to make natural gas prices a critical determinate in power prices. It is now common practice to index power transaction prices to a natural gas price index. Spot market prices for electricity, not surprisingly, respond almost immediately to changes in the price for natural gas. As will be seen in the regional section of this report, markets around the country (PJM, New England, New York, Midwest, Texas, and Western markets), were significantly impacted in early 2003 and again in early 2004 by the spikes in natural gas prices.

Figure I.3 graphs four natural gas price indices for 2003 through May 2004. For illustration purposes, Figure I.4 provides a comparison of the New York natural gas price index and power prices in the New York wholesale market (Zone J is for the New

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[8]NERC Reliability Assessment 2003-2012, December 2003. Energy Ventures Analysis, Inc. data.

[9]Electric Power Research Institute, "Energy Market and Generation Response," June 2003.

[10]EPRI, June 2003, p. 2.

[11]Based on figures from the U.S. Department of Energy, Energy Information Administration, *Electric Power Annual 2002*, December 2003. Natural gas-only capacity is about 19 percent of the total U.S. net summer capacity for 2002 and "dual fired" capacity is about 18 percent. Since most dual fired plants consume natural gas most of the time (and use oil as a back-up), the total natural gas capable capacity is the sum of the natural gas-only capacity and dual fired capacity, for a total natural gas capable capacity of 37 percent of the total U.S. net summer capacity for 2002.

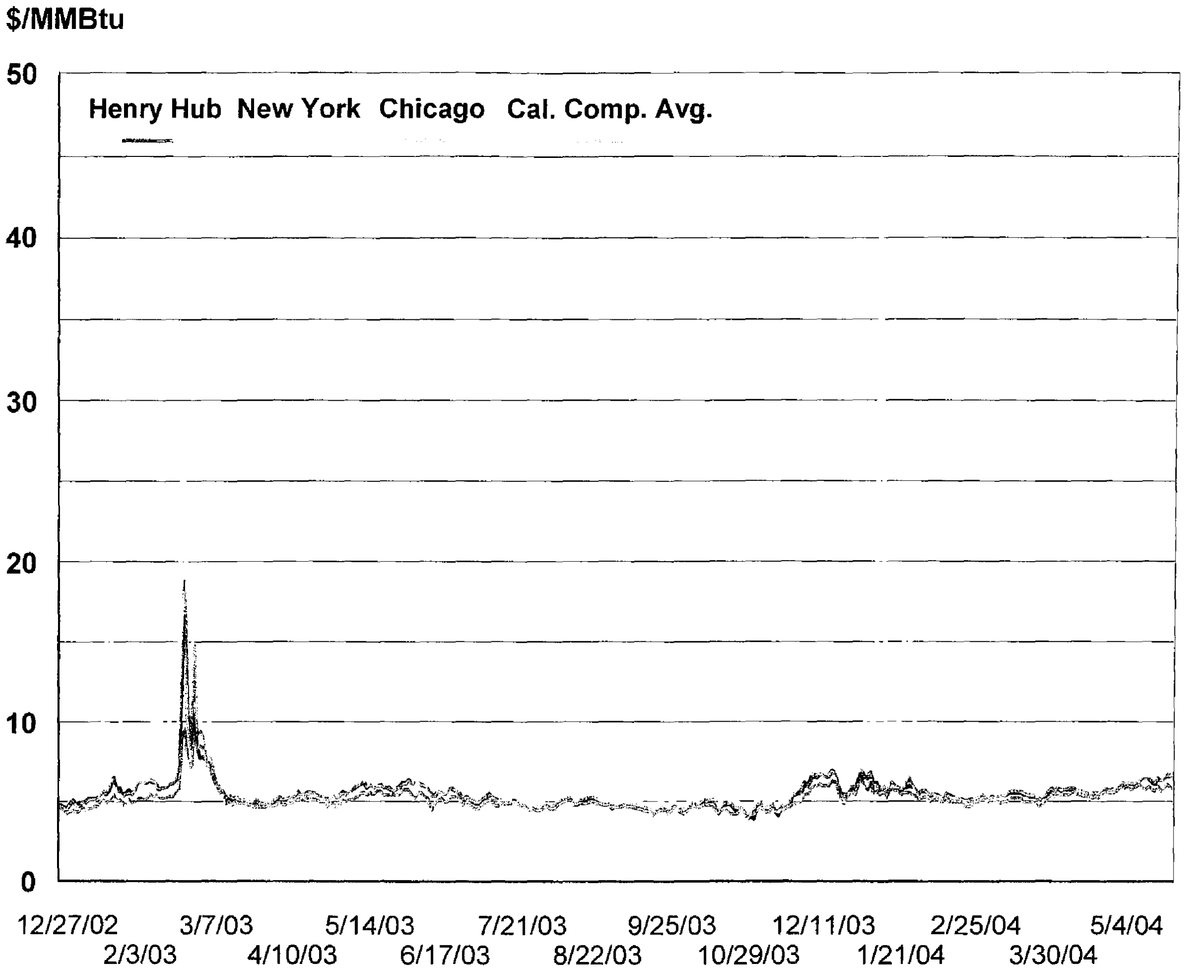

Figure I.3. Daily natural gas price index, January 2003 through May 2004.
Data Source: U.S. Department of Energy, Energy Information Administration, "Natural Gas Weekly Update," data from NGI's Daily Gas Price Index.

York City area, the weighted average monthly price is from the New York ISO). This pattern of a close correlation between power market prices and natural gas prices is repeated in nearly every power market, which are shown in the regional sections. If natural gas prices continue to remain at current levels and continue to surge higher on occasion, this will continue to have a significant impact on both short- and long-term power prices across the country.

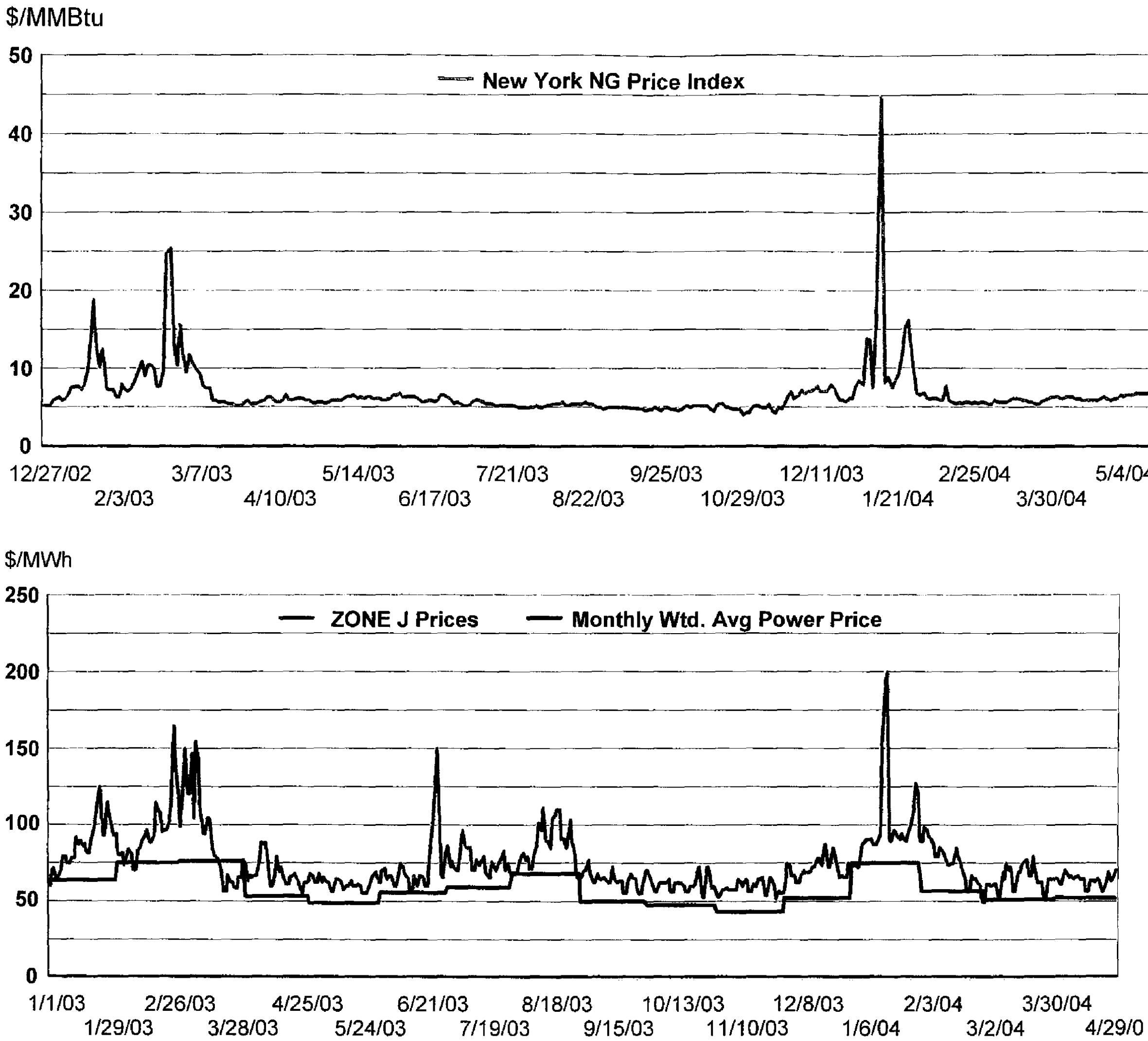

Figure I.4. New York natural gas price index and ISO daily and monthly weighted-average power prices.
Data Sources: DOE/EIA, Platts Megawatt Daily, and New York ISO.

Recent Generation Assets Sales

Relatively little industry attention has been given to the considerable recent transfer of ownership of power plants and other power industry assets in the U.S., and the fact that many of the buyers of these assets have been financial or investor groups. What is noteworthy is that these "financial sponsors" have not been significant owners or holders of power industry assets in any significant amount in the past. A report by Cambridge Energy Research Associates (CERA report)[12] examined 93 power sector asset transfers that occurred between July 2002 and July 2004. This included transactions for power plant purchases, the acquisition of transmission assets, and the pending purchases of two regulated utilities. Over 80 of these asset transfers were for about 275 operating power plants with a net installed capacity of more than 50,000 MW.[13] Nearly 65 percent, or 30,973 MW of the 50,000 MW were acquired by "financial sponsors." These financial sponsors are directly investing in the power industry and include private equity fund managers, leveraged buyout firms, commercial banks, hedge funds, and commodity traders. The CERA report suggests that these investors intend to be relatively short-term owners, since they typically hold assets for two to seven years and are seeking relatively high returns. The other purchasers of these assets were: electric utilities that purchased 11,183 MW, independent generators that purchased 1,749 MW, public power entities that purchased 3,148 MW, Canadian companies that acquired 1,683 MW, and 1,234 MW that were purchased by other entities.

At this time, the total share of the industry's capacity transferred to financial sponsors is relatively small (about 3.4 percent of the total 2002 net summer generating capacity in the U.S.), however, if this trend continues, it could significantly impact the industry's current structure in an unprecedented way.

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[12]Paul Parshley, "Barriers to Exit: Can Financial Sponsors Turn Their New Megawatts into Megabucks?," Cambridge Energy Research Associates, Inc., July 2004.

[13]While this is only about 5.5 percent of the total 2002 total net summer generating capacity in the country, the fact that the 50,000 MW of capacity changed ownership in only a two year period and that it occurred during a relatively turbulent time in the industry's history, makes it notable.

The sellers of these assets vary and are an interesting part of the industry's recent history. These sellers included merchant or independent generating company "fallen angels," that sold about 11,500 MW or 23 percent of the capacity sold during this period.[14] These companies expanded rapidly during the boom years that began in the late 1990s (as shown in Figure I.2 above for new capacity development), but when market conditions changed (such as the much higher natural gas prices), their highly leveraged positions were no longer sustainable and caused them to liquidate assets to raise cash and pay down debt. Similarly, power traders[15] also sold assets they accumulated when they exited the power trading business, selling about 5,700 MW of generating capacity or about 11 percent of the total capacity sold. Also two regulated utilities, Portland General Electric Company (an Enron affiliate) and Illinois Power Company (a Dynegy affiliate) are currently in the process of being sold from this power trading group.

The largest share of the capacity sold was by electric utilities, which sold almost 18,000 MW or about 35 percent of this plant capacity sold. These are traditional electric utilities that are selling non-core assets in a "back-to-basics" strategy to improve credit quality (as discussed above) and financial condition. This includes Allegheny Energy and TECO Energy that are selling assets to restore their financial health after "severe liquidity crises" and other utilities that have not suffered that same type of financial crises, such as AEP, Duke Energy, and Exelon, but are selling non-core assets in their return to more traditional utility business concerns. In addition, about 5,500 MW of generating assets were sold by non-U.S. companies and about 4,700 MW of capacity was sold as "regulatory requirements" – the bulk of this second category were AEP's sales in Texas of their fossil-based units (3,800 MW) and their share of a nuclear plant (630 MW).

[14]CERA included in this group AES Corporation, Calpine, Cogentrix, Mirant, NRG Energy, and Reliant Resources (now Reliant Energy).

[15]Included here are Enron, El Paso Corporation, Williams Companies, Dynegy, and Aquila.

The August 14, 2003 Blackout

The most prominent industry event of 2003 was the blackout that occurred on August 14th. This was the most extensive blackout in North American history, affecting an area of 50 million people and 61,800 MW of electric load in all or part of eight states and one Canadian province.[16] Estimates of the total cost in the U.S. range between $4 billion and $10 billion. Power was not restored for four days in some of the states and parts of Ontario had rolling blackouts for more than a week after.[17] The widespread impact and duration of the outage clearly captured the attention of the general public, politicians, federal and state regulators, electric utilities and competitive suppliers, trade groups and associations, and others in the power industry. It is likely that this event will have a far reaching impact on the industry for the foreseeable future.

A joint task force, the U.S.-Canada Power System Outage Task Force,[18] was charged with investigating the causes of the August 14th blackout and recommending ways to reduce the possibility of a future blackout. Recounting in detail the events that led up to the blackout is beyond the scope of this report. In summary, in the Task Force's report, they placed the causes of the "Ohio phase," that precipitated the cascading blackout that moved across the region on that day, into four general groups as follows:

> Group 1: FirstEnergy [FE] and ECAR [East Central Area Reliability Coordination Agreement[19]] failed to assess and understand the inadequacies of FE's system, particularly with respect to voltage instability and the vulnerability of the Cleveland-Akron area, and FE did not operate its system with appropriate voltage criteria.

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[16]States that were impacted were Connecticut, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania, and Vermont and the Canadian province of Ontario.

[17]This information is based on the report by the joint U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," April 2004.

[18]Their final report is, Ibid., "Final Report on the August 14, 2003 Blackout," April 2004.

[19]This area covers Indiana, Kentucky, the lower peninsula of Michigan, Ohio, western Pennsylvania, and West Virginia.

Group 2: Inadequate situational awareness at FirstEnergy. FE did not recognize or understand the deteriorating condition of its system.

Group 3: FE failed to manage adequately tree growth in its transmission rights-of-way.

Group 4: Failure of the interconnected grid's reliability organization to provide effective real-time diagnostic support.[20]

In general, the task force placed the cause of the blackout as from "deficiencies in specific practices, equipment, and human decisions" and, more specifically, as "deficiencies in corporate policies, lack of adherence to industry policies, and inadequate management of reactive power and voltage."[21]

The Task Force outlined 46 recommendations in their final report. These are also arranged into four groups: Group I: Institutional Issues Related to Reliability (14 recommendations), Group II: Support and Strengthen NERC's Actions of February 10, 2004 (17 recommendations), Group III: Physical and Cyber Security of North American Bulk Power Systems (13 recommendations), and Group IV: Canadian Nuclear Power Sector (2 recommendations).

The Task Force's first recommendation is: "Make reliability standards mandatory and enforceable, with penalties for noncompliance." They state that "the single most important" recommendation they make is that "the U.S. Congress should enact the reliability provisions in H.R. 6 and S. 2095 to make compliance with reliability standards mandatory and enforceable."[22] They note that with such legislation, many of their other recommendations could be achieved during implementation of the reliability legislation. This recommendation has not been met and is unlikely to happen, at this time, until sometime during 2005 at the earliest.

Industry restructuring is not addressed directly in the Task Force's report. However, recommendation number 12 is: "Commission an independent study of the

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[20]Ibid., p. 18.

[21]Ibid.

[22]Ibid., p. 2.

relationship among industry restructuring, competition, and reliability." While it was left unstated directly, clearly the recommended change from the current voluntary reliability standards to mandatory and enforceable standards is being made in recognition of the fact that incentives and conditions have changed in the industry. That is, with vertically structured and regulated utilities, the voluntary standards worked reasonably well. But, as a result of restructuring and the emerging new industry structure, reliability rules and standards need to adjust as well.

Transmission System Adequacy

A related issue to reliability is transmission capacity, expansion, and future investment. This is obviously a critical component of reliability, but it is of critical importance in how competitive power markets perform as well. The transmission system is the backbone of the power infrastructure, which the generation and distribution components and wholesale and retail customers depend. Power system engineers define and separate reliability into two main components, (1) system adequacy, which is the electric system's ability to supply the aggregate electrical demand and energy requirements of customers at all times; and (2) operating reliability, which is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements.[23] However, a third aspect to reliability can now be added, market support or sustenance. Therefore, in the restructured environment, the ability to move power within and across regions reliably requires, in addition to meeting minimum load requirements (reliability definition 1) and without disruptions (reliability definition 2), that there also be sufficient supply for power markets to be relatively stable and reasonably competitive.[24] This requires both sufficient generation *and* transmission.

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[23]Definition used by the North American Electric Reliability Council (NERC), among others.

[24]"Relatively stable" meaning that markets fluctuate with changing conditions within reasonable bounds and proportionately (as fuel prices, economic conditions, etc. change) and "reasonably competitive" means they are operating without excessive supplier market power.

However, transmission expansion is not expected to keep pace with generation capacity and load growth. Between 2003 and 2007 the North American Electric Reliability Council (NERC) expects electricity demand to grow by about 67,000 MW.[25] They are projecting average annual peak demand growth of 1.9 percent for the U.S. for the 2003 through 2012 period. Resource additions over the 2003 to 2007 period is expected to be about 89,000 MW, depending upon the number of merchant plants actually placed in service. Longer-term, more than 117,000 MW of new capacity for the U.S. during the 2003 through 2012 period is expected, or potentially a 14 percent increase over that existing in 2002. However, according to NERC, over 7,400 miles of new transmission (230 kV and above) are proposed to be added through 2007 and about 11,600 miles are expected to be added over the 2003 to 2012 period – a 5.6 percent increase in the total amount of installed transmission in North America for the period. Planned transmission, circuit miles of 230 kV and higher, for the 2003 to 2007 period are expected to increase 3.1 percent for the eastern interconnection and increase 3.5 percent for the western interconnection.

A one-to-one growth rate for transmission and generation capacity and load should not be expected, since transmission investments are "lumpy," that is, they are made in large increments and can support large amounts of generation investments over time. However, given the expected demand and generation capacity growth, the slower expected transmission expansion rate is, at the very least, a cause for concern. In addition, as NERC states "the transmission system is being subjected to flows in magnitudes and directions that were not contemplated when it was designed or for which there is minimal operating experience."[26]

A report prepared by Eric Hirst for the Edison Electric Institute and the U.S. Department of Energy suggests that lagging transmission growth rates are not a new

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[25]North American Electric Reliability Council, "2003 Long-Term Reliability Assessment," December 2003.

[26]NERC, "2003 Long-Term Reliability Assessment," p. 34.

occurrence.[27] Hirst reports that normalized transmission capacity (MW-miles/MW-demand) grew at an average annual rate of 3.3 percent between 1978 and 1982. In the following 20 years, 1982 to 2002, normalized transmission capacity declined at a rate of 1.5 percent per year.[28] Similarly, transmission miles per GW of demand were increasing at 2.6 percent per year for 1978 to 1982, and decreasing at a rate of 1.6 percent per year over the next 20 years. Hirst also reports that annual investment in transmission facilities by investor-owned utilities (inflation adjusted) fell at an average rate of $83 million per year between 1975 and 1999. However, from 1999 through 2003, transmission investment *increased* at an average annual rate of $286 million (the author was not able to explain the sudden reversal in the investment trend.)[29]

Normalizing the NERC transmission capacity data, Hirst reports that normalized transmission capacity declined by almost 19 percent between 1992 and 2002 and is projected to decline by 11 percent for 2002 to 2012.[30] Hirst also shows that normalized transmission capacity declined in all ten reliability regions between 1989 and 2002, ranging from 14 percent to 27 percent declines.[31] Hirst notes that: "[o]f the 416 transmission projects planned for the next 10 years, [footnote omitted] 95% are shorter than 100 miles, with an average length of only 18 miles. These numbers suggest that most planned transmission projects are local in scope and are not intended to address large regional issues."[32]

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[27]Eric Hirst, "U.S. Transmission Capacity: Present Status and Future Prospects," June 2004. Prepared for the Edison Electric Institute and the U.S. Department of Energy.

[28]Hirst, p. 7.

[29]Ibid.

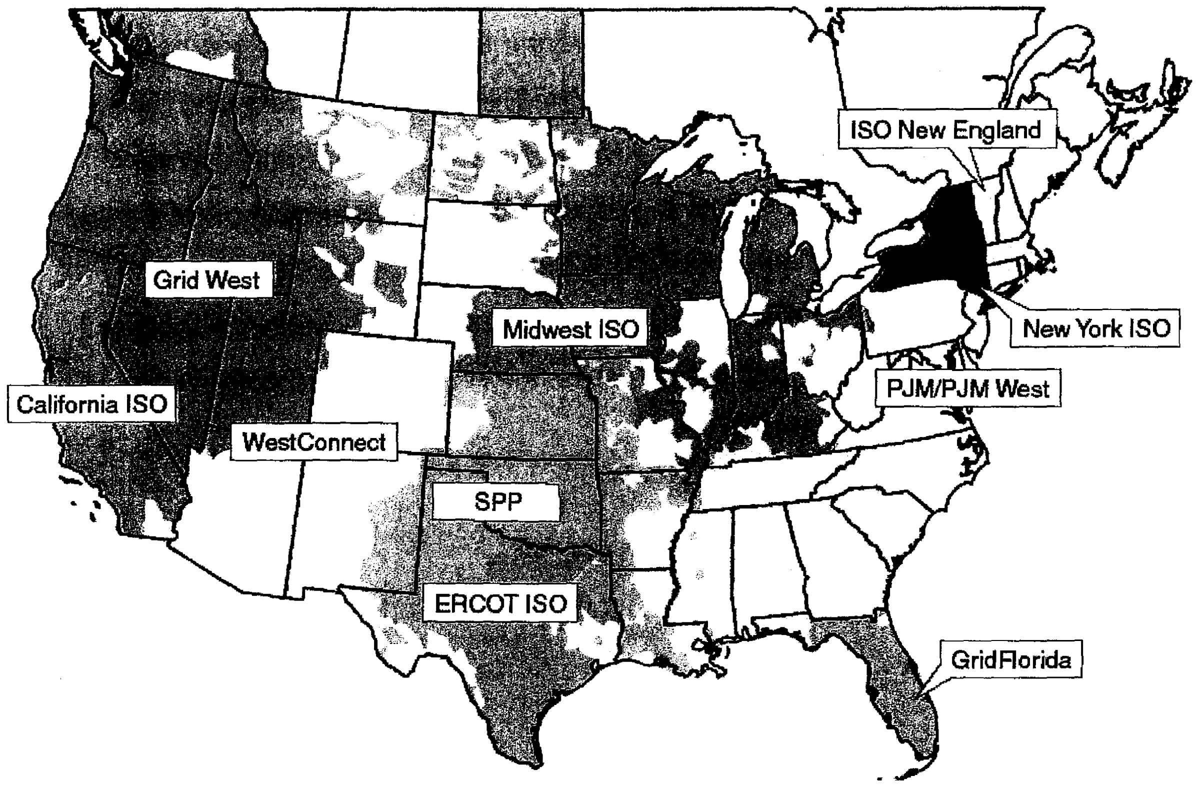
[30]Hirst, p. 9.

[31]Hirst, p. 11.

[32]Hirst, p. 14.

Regional Transmission Organization Development and Organization of this Review

The remaining sections of this report are organized into seven regional sections. The map shown in Figure I.5 identifies the current approved RTOs and ISOs and show the regional transmission organization and the associated power markets discussed in the regional sections. The sections of this report and how they correspond with the region on the map are as follows: Section II, covers the Mid-Atlantic region, which is primarily the original PJM area (eastern Pensylvania, New Jersey, Maryland, D.C., and a small part of Virginia); Section III, covers the New England region and ISO New England; Section IV, covers New York and that state's wholesale market and the New York ISO; Section V, covers the Midwest, which includes the Midwest ISO and Southwest Power Pool (SPP); Section VI, covers the southeast; Section VII covers Texas and the ERCOT ISO; and Section VIII covers the West. In each regional section, the state retail markets are discussed.



Note: Map includes service territories of transmission-dependent utilities.
This map is available to EEI electric company members at **http://www.eei.org/products/rto/maps/rto_map.pdf** (PDF) or **rto_map.ppt** (PowerPoint)
 Service territory data source: POWERmap, 2nd quarter 2002 release, © Platts, a Division of the McGraw Hill Companies.

Figure I.5. Approved RTOs and existing ISOs, utility participation as of May 2004. Source: Edison Electric Institute.

How wholesale market performance is measured

Among the principal reasons[33] for the movement away from regulation and toward generation competition was the belief that competition would provide better incentives to control costs and that these cost savings would be passed on to consumers–resulting in lower prices for all customer classes.

The examination of the performance of the wholesale markets in this report is based on the extent to which this goal of developing a competitive market is being met. Ideally, the economic textbook case of a perfectly competitive market, there would be many suppliers vying for business. Potential new entrants would encounter few or no entry barriers and this ease of entry[34] would provide an additional incentive to existing suppliers to control costs and offer competitive prices to retain customers. No single supplier or group of suppliers could exercise any control over the price or manipulate it in any significant way. In other words, in a *perfectly* competitive market, suppliers are "price takers" and base their choice of the quantity to supply to the market on this market-determined price. In this perfectly competitive market case, the market price will approximate the marginal cost of supply at the market-clearing quantity.

The ability of a supplier or group of suppliers to raise and maintain the price above what would occur in a competitive market is referred to as their market power. Market power is the degree of price leveraging ability a supplier or suppliers have for "price making" ability, rather than being the price takers of the perfectly competitive market. The more a firm can charge a price that exceeds the marginal cost and exert its influence upon the price, the greater the firm's degree of market power.[35] The price-

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[33]Other reasons include increased use of innovative technologies in generation and more customer options in terms of price, fuel source, and service.

[34]For example, no or little sunk investment costs, where either the investment costs are low or the capital invested can be easily redeployed to another enterprise.

[35]This can be estimated with the "Lerner Index," which is defined as:

(Price - Marginal Cost)/Price

which measures the markup of price over marginal cost (as a percentage of price). The larger the Lerner Index, the greater the firm's market power. If the Lerner Index equals 0.5, then 50 percent of the price is the mark-up above marginal cost; if it equals 0.02, then just two percent of the price is mark-up above marginal cost. If the Index equals 0.5, it may indicate significant market power and require some action; if taking competitive firm that has no market power cannot pick its own price or influence it in any significant way. However, there are upper bound limits on price that hold even in the extreme case of market power of an unregulated monopolist that faces no meaningful threat of market entry from rival firms. Such limits reflect that the price cannot exceed what consumers are willing to pay for the product (that is, it cannot exceed demand at the quantity the monopolist wants to produce), nor can a monopolist charge a price that is sufficiently high that it creates a strong incentive for other firms to find ways around the entry barriers to the market or that encourages consumers to seek alternatives.

Of course, experience tells us that markets are routinely less than ideal or perfect. Suppliers often have at least some degree of control over the price. When this control is relatively modest, as with many markets, no corrective action is required or taken. For example, if a manufacturer can raise and maintain the market price ten percent above a competitive level, and is able to do so without using any illegal anti-competitive practices (such as price fixing or in collusion with other firms),[36] this relatively modest impact on price is not likely to lead to calls for corrective regulatory action. Indeed, some corrective actions may cause more harm than good by deterring new entrants or imposing additional compliance costs. Also, with low entry barriers, over time the higher price will draw the attention of potential new suppliers who will drive the price down closer to the competitive level when they enter the market. Problems arise when the price control is relatively large and has persisted, or has the potential to persist, for a long time.

How much control or price leverage a firm has is based on three factors: the overall demand characteristic of the product, the market concentration or market share of the firm, and the supply characteristics. These three factors together determine how much market power a firm can exercise. No single factor by itself would indicate a firm

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it is only 0.02, it is unlikely to raise any calls for governmental action.

[36]These and other anti-competitive practices to raise the price are illegal under Federal law. However, the unilateral exercise of market power by itself is not illegal.

has considerable market power. For example, if a firm had a substantial market share, say 80 percent of the market, but entry or increased output from other firms was relatively easy and customers had suitable alternatives to the firm's product, then its actual market power potential may in fact be very low.

Unfortunately, in electric markets all three factors clearly play a role. Demand for electricity is very inelastic, particularly in the short-run (less than one year) since customers have few practical alternatives and the long life of major electrical appliances makes it difficult to respond to price changes quickly for most customers. Markets are very concentrated for most geographic regions, even for multi-state wholesale regions. Market entry from other firms requires time to build new generation and is limited from outside the area by transmission constraints, which also require time to relieve. Also, mass storage of electricity for later use during peak hours is generally impractical for many regions of the country.[37] As economic theory would predict, because during peak hours supply is often very inelastic, that is, the quantity supplied is not very responsive to the price, markets are relatively concentrated, and demand is also very inelastic, market power has been very significant, particularly during peak hours.

The way a supplier can exercise market power in electric power markets, if they have some degree of price leverage,[38] is to either physically or economically withhold output from the market. Physical withholding is the actual withdrawal of capacity, such as claiming that a plant or plants are down for maintenance or withdrawing capacity for other reasons. Economic withholding is bidding a relatively high price with the expectation that either the plant or plants will not be selected for dispatch, or if they are selected, the owner will receive a much higher price than the marginal cost. In either case, withholding is profitable because the revenue lost from the idled capacity is more than made up for by the increased revenue gained by the operating plants that receive the higher price.

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[37]Pumped hydro storage, obviously, requires hydro resources to be available, and when it is available, it is usually not a significant portion of the total capacity required to meet demand.

[38]If a firm has no or very little market power, then raising the price will mean the loss of all or a substantial number of the firm's customers.

For each of the regions examined in the following sections, to the extent available, analyses of wholesale market performance are summarized and presented in the wholesale discussion. Unfortunately, at this time, not all regions have had a rigorous and independent market performance analysis conducted.

How retail market performance is measured

The actual prices paid by retail customers that choose a competitive supplier are not made public. Measuring an actual price trend, and the potential benefits to consumers, is therefore not always directly observable. The review of retail markets summarizes what we can observe in the markets, in terms of offers being made to residential customers, the potential savings opportunities these offers present, the number of suppliers in the area, the type of offers being made, and the percent of customers that have selected an alternative supplier, among other factors. These performance measures are, when available, included in the regional summaries in the subsequent sections.

These potential performance indicators in isolation do not determine whether a retail market and its design are succeeding or failing. Rather, considered in tandem with an assessment of wholesale market developments, these indicators present a picture of how retail markets are evolving. Since these markets began relatively recently, and the transition period continues for most areas, markets are still evolving. Therefore, the purpose of this report is not to judge success or failure of competition overall, but to present facts to assess the state of retail and wholesale markets today.

Retail market performance is highly dependant on prices in the wholesale market. Most retail markets have overall price constraints that seldom fluctuate along with changing conditions in the wholesale market or are adjusted after a considerable time lag. The retail standard offer, or the "price-to-compare," is the price for generation service paid by a retail customer who does not select a competitive supplier. These customers continue to receive power supplied by the distribution company that still owns generation, an affiliated generation owner, an unaffiliated supplier or suppliers, or some combination of all of these generation sources.

The standard offer or price-to-compare is the benchmark or "price-to-beat" not only to inform customers to allow them to make a choice, but is also an indicator for use by competitive suppliers considering entry into a retail market. The effect of the retail price constraints depends on the amount of the available "headroom," which is the difference between the generation price-to-compare and the cost to procure power to serve retail customers.

As is illustrated in Figure I.6, the generation charge or price-to-compare, relative to the cost to competitive suppliers to obtain or generate power, will determine the

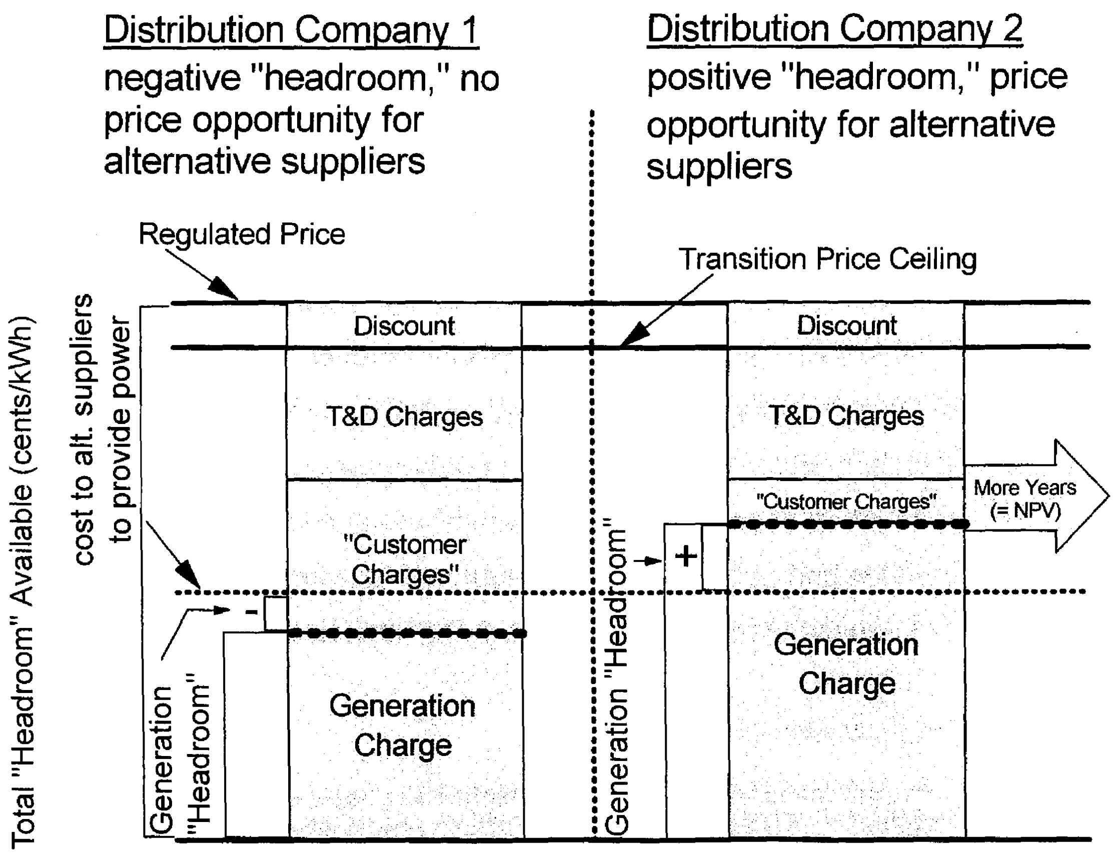


Figure I.6. Examples of two different distribution companies with different generation cost and with the same cost of procuring power for alternative suppliers.

amount of "headroom" available for alternative suppliers to compete. The distribution companies in Figure I.6 have the same beginning regulated price, discount,[39] and transmission and distribution charges. In this hypothetical example, the customer charges are greater for distribution company one on the left side of the figure than distribution company two on the right. To collect the same net present value for both companies (assuming they are the same for both companies), the transition period runs longer for distribution company two. However, the larger customer charge (or "CTC") for distribution company one results in the generation charge being reduced (in order to remain under the price ceiling[40]), in this case, below the cost to alternative suppliers to either procure power in the wholesale market or to generate it themselves–this cost is represented by the dotted line running across the figure.

Alternative supplier costs also include marketing, risk management, overhead, and normal return-on-investment costs, not only the direct cost of the power. In this first example, alternative suppliers will have to charge a price above what customers would pay if they stayed with the distribution company, therefore, in this case, there is "negative headroom." In the case of distribution company two in Figure I.6, the generation charge or price-to-compare is above the cost to alternative suppliers to provide power, meaning there is "positive headroom" and an opportunity for these suppliers to entice customers away from the distribution company or default provider.

If there is sufficient headroom, suppliers are able to offer customers an opportunity to save and can entice customers away from the price-to-compare (illustrated by distribution company two).[41] However, the headroom may be too small to cover all the costs of supplying the retail customers, be nonexistent, or even

[39] Not all states have a discount, of course.

[40] Another way of considering this is to start with the previously regulated rate, then subtract the discount (if any), T&D charges, and the customer charges. Then, what is left over is available for the generation charge.

[41] Of course, as demonstrated by the existence of "green" suppliers, who offer power generated to some degree by renewable or "clean" energy resources, price is not the only consideration customers use to select a supplier. Other factors include reliability, fuel source, and contract terms. While a small subset of customers are willing to pay a premium for these other factors, price is still the dominant consideration for most customers.

negative–that is, where the cost of securing and delivering power to the retail customer exceeds the retail price charged by the distribution company (as illustrated by distribution company 1).[42] Assuming alternative suppliers do not want to operate at a loss for too long, they will not enter or will leave a market under these conditions. In general, of the relative factors of retail price for generation and the wholesale cost of power, the wholesale cost is more volatile. Price fluctuations and volatility, or the future threat of it, can increase the cost to alternative suppliers and be a determining factor in a decision to participate or continue to participate in a market.

Obviously, if the beginning-regulated rate is relatively lower to start with, the amount of available overall headroom (that is, what is available for all the price components) will be relatively low when compared with a higher-rate distribution company. Also, if wholesale prices are relatively high compared to what customers are paying for the price-to-compare, then fewer suppliers will enter the market. This lack of headroom is the primary reason that many retail markets currently have very little activity and, where there is retail market activity, it is primarily within states or distribution companies that had relatively higher costs before restructuring began.

[42]An extreme example of negative headroom is California, which led one distribution company (PG&E) to the filing for bankruptcy protection and severe financial difficulties for another. Distribution companies in other states, for example, Massachusetts and Pennsylvania (GPU), have received upward adjustments to the standard offer price to recover the increased cost of obtaining power in the wholesale market (made necessary because the distribution companies sold their own generating capacity). In the Pennsylvania/GPU case, a settlement reached in June of 2001 allows GPU to defer for ratemaking and accounting purposes the difference between what it can charge customers for generation under the rate cap and its actual cost to supply electricity. The deferral provision of the settlement allows GPU to retain unrecovered generation costs on its books until 2010. Overall customer rates will not increase (the rate cap was extended through 2007), but the "shopping credit" or price-to-compare will increase. The settlement ends the Competitive Transition Charge (CTC) in 2015. GPU stated that it lost $47 million on electricity supply in Pennsylvania in 2000 and estimated it would lose an additional $250 million in 2001 without rate relief.

SECTION II
Mid-Atlantic Region

Mid-Atlantic Wholesale Market: PJM Interconnection[1]

Overview and Summary

PJM Interconnection, L.L.C.'s (or PJM) origins date back to 1927 when three companies formed the first power pool, the "Pennsylvania-New Jersey Interconnection." In 1956, three more companies were added and the pool became the "Pennsylvania-New Jersey-Maryland" Interconnection (its beginning as "PJM"). In 1981 PJM added two members, bringing membership to eight companies. Today PJM claims to operate the largest wholesale electric market in the world and coordinates the movement of electricity throughout the mid-Atlantic states and into the Midwest. PJM is a Regional Transmission Organization (RTO) by FERC designation and rulemaking.

Figure II.1, is a map of PJM's control area (as of May 2004), which now includes all or parts of Delaware, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia. PJM's control area currently has approximately 35 million people in it, 800 generation sources of various fuel types, 106,000 MW of generation capacity, peak demand of nearly 87,000 megawatts, 446 million megawatt-hours of annual delivered energy, 25,000 miles of transmission lines, and 275 market participants. Pending regulatory and other considerations, PJM may more than double in size if additional members are integrated into the system to the south and west of its current borders.

Because of its relatively long history as a coordinated power pool, PJM was able to quickly develop into an Independent System Operator (ISO) and perform the market coordination it does today. For this reason PJM currently has the most developed wholesale market in the U.S. and has considerable information on its operations. In

[1]The introduction and explanatory material presented here on PJM's operations and markets is from various PJM publications on their website, www.pjm.com.

addition to operating and monitoring its electricity markets, PJM also plans transmission and generation expansion for the area.

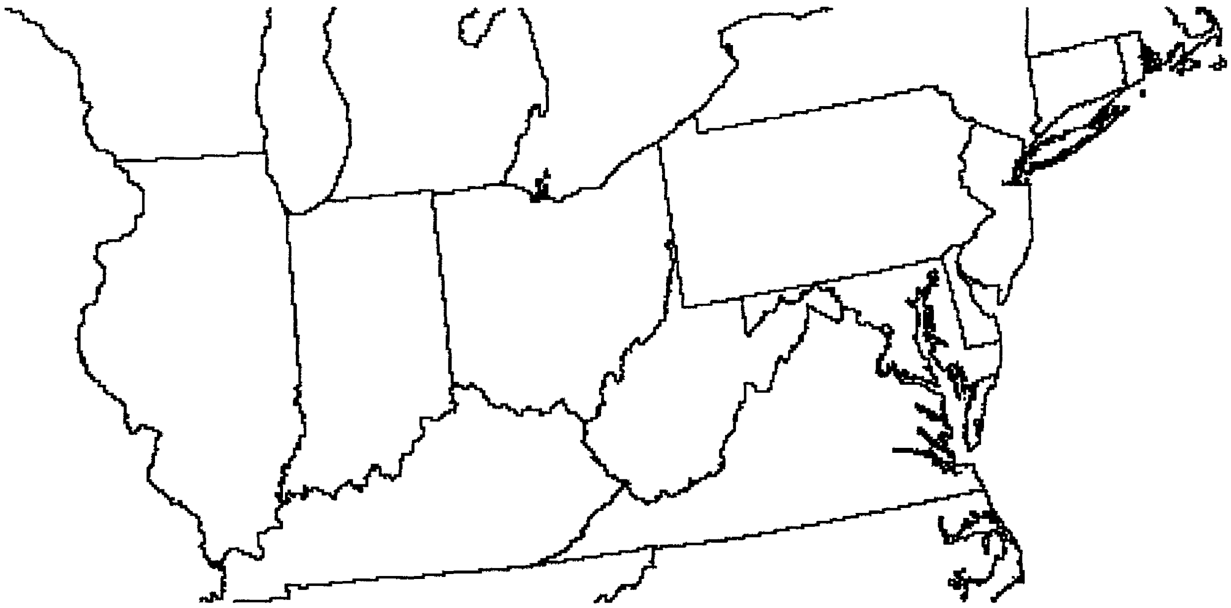


Figure II.1. The PJM Interconnection control area–which includes the original PJM region (MAAC Control Zone) and the PJM Western Region.
Source: PJM Interconnection, May 2004.

<u>PJM Markets</u>

PJM operates a number of different power markets, including: day-ahead and real-time energy markets; daily, monthly, and multi-monthly capacity credit markets; several ancillary service markets; and monthly Financial Transmission Right (FTR) auction markets. PJM introduced nodal energy pricing with market-clearing prices on April 1, 1998 and nodal, market-clearing prices based on competitive offers on April 1, 1999 (locational marginal pricing or LMP). PJM implemented a competitive auction-based FTR market on May 1, 1999. Daily capacity markets were introduced on January 1, 1999 and were broadened to include monthly and multi-monthly markets in mid-1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000.

Energy Markets

The day-ahead energy market is a forward market in which day-ahead locational marginal prices (LMPs) are calculated for each hour of the next operating day based on generation offers, demand bids, and bilateral transactions submitted in the day-ahead market. The real-time energy market is based on current day operations in which real-time LMPs are calculated at five-minute intervals based on the actual system operating conditions. Figure II.2 plots PJM's daily peak hour average prices in the real-time market (calculated from weighted average hourly LMP prices) for January 2003 through April 2004. As discussed in Section I, the impact of higher natural gas prices in early 2003 and 2004 can be seen in the daily average prices of both years.

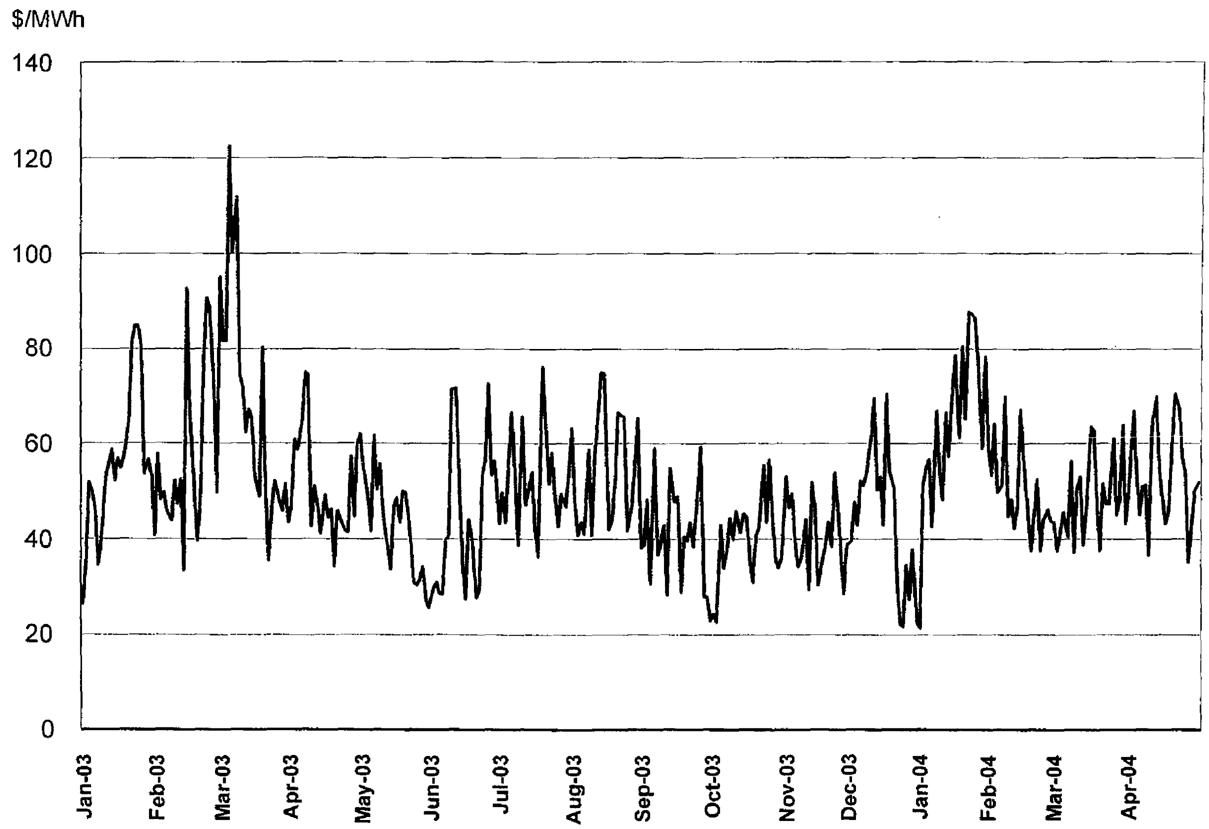
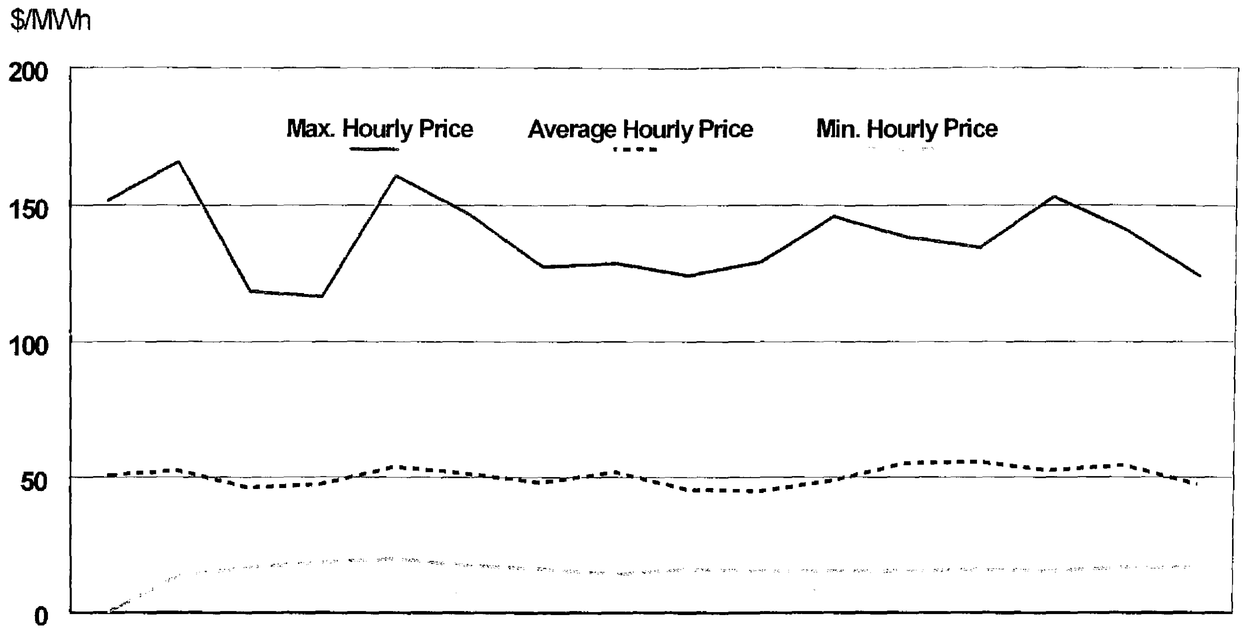


Figure II.2. Daily peak hour average prices in PJM's Real-Time market (from weighted average hourly LMPs).
Data source: PJM Interconnection, June 2004.

Figure II.3 shows the peak hour maximum, average, and minimum prices in PJM's real-time market from January 2003 through April 2004. The values are shown in the table below the graph for each peak hour.



Hour	700	800	900	1000	1100	1200	1300	1400	1500	1600	1700	1800	1900	2000	2100	2200
Max.	152	166	119	117	161	147	128	129	125	130	146	139	135	154	142	125
Avg.	51	53	46	48	54	52	49	52	46	45	49	56	56	53	55	48
Min.	0	14	17	19	20	17	17	14	16	16	16	16	16	16	17	17

Figure II.3. Peak hour maximum, average, and minimum prices in PJM's Real-Time market, January 2003 through April 2004.
Data Source: PJM Interconnection, June 2004.

Buyers and sellers of energy in PJM can decide whether to meet their energy needs through self-supply, bilateral purchases from generation owners or market intermediaries, through the day-ahead market or the real-time balancing, or spot market. Energy purchases can be made over any time frame from instantaneous real-time balancing market purchases to long-term, multi-year bilateral contracts. Purchases may be made from generation located within or outside the PJM control area. Generation owners can sell their output within the PJM control area or outside the control area and can use generation to meet their own loads, to sell into the spot market or to sell bilaterally. Generation owners can sell their output over multiple time frames from the real-time spot market to multi-year bilateral arrangements.

Capacity Markets

Under PJM rules, each load-serving entity (LSE) has the obligation to own or acquire capacity resources equal to the peak load that it serves plus a reserve margin. LSEs can acquire capacity by buying or building units, by entering into bilateral arrangements with terms determined by the parties, or by participating in the capacity credit markets operated by PJM. Collectively, these arrangements are now known as the Unforced Capacity Market (UCAP). The PJM capacity credit markets (CCM) provide a mechanism to balance the supply of and demand for capacity not met through the bilateral market or through self-supply. Capacity credit markets are intended to provide a transparent, market-based mechanism for new, competitive LSEs to acquire the capacity resources required to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. PJM's daily capacity credit markets enable LSEs to match capacity resources with changing obligations caused by daily shifts in retail load. Monthly, multi-monthly, and interval capacity credit markets enable longer-term capacity obligations to be matched with available capacity resources. Prices and performance, including a significant problem with manipulation of the capacity credit markets, are discussed below.

Ancillary Services: Regulation Market

Regulation is one of six ancillary services defined by the FERC in Order No. 888. Regulation is required to match generation with short-term increases or decreases in load that would otherwise result in an imbalance between the two. Longer-term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. Market participants can acquire regulation in the regulation market in addition to self-scheduling their own resources or purchasing regulation bilaterally. The market design implemented by PJM provides incentives to owners based on current, unit specific opportunity costs in addition to the regulation offer price. The market for regulation permits suppliers to make offers of regulation subject to a bid cap of $100 per MW, plus opportunity costs. A regulation market was introduced on June 1, 2000, and modified on December 1, 2002.

Ancillary Services: Spinning Reserve

Spinning reserve is an ancillary service defined as generation synchronized to the system and capable of producing output within 10 minutes. Spinning reserve can be provided by a number of sources including steam units with available ramp (incidental spinning), condensing hydro units, condensing combustion turbines (CTs), CTs running at minimum generation, and steam units scheduled a day ahead to provide spinning reserves. PJM introduced a market for spinning reserves on December 1, 2002.

Financial Transmission Rights

A Financial Transmission Right (FTR) is a financial instrument that entitles the holder to receive compensation for Transmission Congestion Charges that arise when the transmission grid is congested in the day-ahead market and differences in day-ahead Locational Marginal Prices (LMPs) that result from the dispatch of generators out of merit order to relieve the congestion. Each FTR is defined from a point of receipt (where the power is injected onto the PJM grid) to a point of delivery (where the power is withdrawn from the PJM grid). For each hour in which congestion exists on the transmission system between the receipt and delivery points specified in the FTR, the holder of the FTR is awarded a share of the Transmission Congestion Charges collected from the market participants.

FTRs are designed to provide a hedge against congestion charges in the day-ahead market for firm transmission service customers, who pay the costs of the transmission system, including any congestion charges. PJM provides three ways to acquire FTRs: the annual FTR auction, the monthly FTR auction, and the FTR secondary market. The annual auction uses a multi-round auction process that offers for sale the entire transmission entitlement available on the PJM system on a long-term basis. The proceeds from the annual FTR auction are allocated through the Auction Revenue Rights (ARR) mechanism. The ARRs are allocated to network transmission customers and to firm point-to-point transmission service customers for the annual planning period. ARR holders can elect to directly convert an ARR into an FTR instead of bidding in the auction. PJM completed the first annual auction of FTRs in May 2003. The monthly FTR auction offers for sale any residual transmission entitlement that is available after FTRs are awarded from the annual FTR auction and also allows market participants an opportunity to sell FTRs they are holding. Before the annual auction was instituted, FTRs were allocated annually to firm transmission service customers and remaining FTRs were auctioned in the monthly auction. The FTR secondary market is a bilateral trading system that facilitates trading of existing FTRs between PJM members.

FTRs are financial entitlements that enable holders to receive revenues (or charges) based on transmission congestion measured as the hourly energy locational marginal price differences in the day-ahead market across a specific path. An FTR does not represent a right to physical delivery of power. FTRs can protect transmission service customers, whose day-ahead energy deliveries are consistent with their FTRs, from uncertain costs caused by transmission congestion in the day-ahead market. Transmission customers are hedged against real-time congestion by matching real-time energy schedules with day-ahead energy schedules. FTRs can also provide a hedge for market participants against the basic risk associated with delivering energy from one bus or aggregate to another. An FTR holder does not need to deliver energy in order to receive congestion credits. FTRs can be purchased with no intent to deliver power on a path.

The hourly value of an FTR is based on the FTR megawatt reservation and the difference between day-ahead LMPs at the point of delivery and the point of receipt designated in the FTR. An FTR *obligation* is positive when the path designated in the FTR is in the same direction as the congested flow. However, an FTR obligation is negative (a charge or liability) when the designated path is in the opposite direction of the congested flow. An FTR *option* is also positive when the path designated in the FTR is in the same direction as the congested flow, but an FTR option's value is zero when the designated path is in the direction opposite to the congested flow. The option is intended to eliminate the risk from holding an FTR when transmission congestion occurs in the opposite direction of the path specified in the FTR.

FTRs are issued through PJM's simultaneous feasibility test that determines the amount of FTRs for each participant based on anticipated power transactions and transmission requirements and the system's ability to accommodate these requirements. When the actual system conditions result in more congestion than what was expected, there may be an insufficient number of FTRs issued to cover all actual congestion, a condition referred to as "unhedgeable congestion." It is unclear at this time just how much congestion on the PJM system is "unhedgeable."

While this situation may be occasional, there are transmission system constraints, such as with a number of "load pockets" scattered throughout PJM and in other parts of the country that could result in significant congestion charges. It is also not clear just how common and pervasive these types of constrained conditions are throughout the country. The western U.S., for example, has many isolated load pockets, including some large urban areas that are separated by long distances. Supporters of the LMP/FTR concept have argued that the process sends the correct economic incentive to build generation in the transmission-constrained area or to find ways to relieve the congestion with additional transmission capacity. However, critics have argued that adding additional transmission lines may require the siting of new transmission rights-of-ways, which is always difficult and costly. Even additional capacity on existing rights-of-ways are often difficult and costly as well. Moreover, as critics note, it is already known that additional generation is likely needed in the area and that additional transmission capacity would ameliorate the congestion problem, so the additional cost from the LMP "incentive" is superfluous and will only result in higher costs for customers.

Market Performance Update

Several analyses summarized in previous years' Performance Reviews by Mansur[2] and Bushnell and Saravia[3] indicated that there were appreciable levels of supplier market power in PJM markets. However, these studies used data from early in the operation of the markets and, while instructive on methodology and market design issues, are of limited value to judge how these market have preformed recently. There have been changes in market design and operation in the last several years and market participants have become more familiar with the operation through experience. This will likely affect both the ability of market participants to find ways to profitably use the rules and procedures to their advantage and also time for PJM, FERC and other participants to respond with changes to counteract strategies that may be harmful to customers' and other participants' welfare. Unfortunately, there are no recent comprehensive, independent, and academically defensible analyses of PJM markets.

PJM's own Market Monitoring Unit (MMU) estimates a price-cost markup index, that is basically a Lerner index[4] that is load-weighted and normalized. They calculate and present average monthly load-weighted markup indices that generally are at levels that would not raise any particular concern about the performance of PJM's markets. In

[2]Erin T. Mansur, "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market," University of California Energy Institute (PWP-083), April 2001. Also, for a more recent analysis (using 1999 market data), see Mansur, "Vertical Integration in Restructured Electricity Markets: Measuring Market Efficiency and Firm Conduct," Center for the Study of Energy Markets Working Paper, University of California Energy Institute (CSEM WP 117), October 2003.

[3]Bushnell and Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," May 2002.

[4]The markup or Lerner index is calculated as: (Price - Marginal Cost)/Price, as discussed in Section I.

the MMU's reports of the years 2001, 2002, and 2003[5] the average markup for both 2001 and 2002 was calculated to be 0.02 (that is, 2 percent of the price is mark-up above marginal cost) and 0.03 (3 percent of price) for 2003. The maximum monthly markup was 0.05 (5 percent) for January 2001, 0.04 (4 percent) for July 2002, and 0.06 (6 percent) for February 2003. The minimum monthly market was less than 0.01 (less than 1 percent) for November 2001 and again for several months in 2002, and 0.01 (1 percent) for August 2003. The MMU also calculated monthly markups assuming that there is a 10 percent markup over cost, since generators in PJM are allowed to provide cost-based offers with up to a 10 percent markup over cost. An adjusted markup calculation removes the assumed potential 10 percent increase over cost and results in the average markups to increase to 0.11 (11 percent) for both 2001 and 2002, and 0.12 (12 percent) for 2003. The adjusted monthly maximum of 0.13 (13 percent) in January 2001, again in July 2002, and 0.15 (15 percent) in February 2003 and a minimum of 0.09 (9 percent) for October 2001, 0.10 (10 percent) for several months in 2002 and again in 2003.

The MMU provides little description on how their markup index is calculated, therefore, their methodology cannot be fully evaluated without more detail. They do indicate that when calculating the index, they compare the marginal unit's price offer to the cost of the highest marginal cost unit operating, not the marginal cost associated with the marginal unit.[6] This may simplify the calculation, but it will not pick up any physical or economic withholding strategies (since, as discussed in Section I, they are intended to force the dispatch of the higher marginal cost units to drive up the price) and will likely understate the markup index (since the difference between price and marginal cost is reduced).

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[5]Market Monitoring Unit, PJM Interconnection, L.L.C, "PJM Interconnection State of the Market Report 2001," June 2002; Market Monitoring Unit, PJM Interconnection, L.L.C, "2002 State of the Market Report," March 5, 2003; and Market Monitoring Unit, PJM Interconnection, L.L.C, "2003 State of the Market," March 4, 2004.

[6]MMU, "2003 State of the Market," p. 53.

Mid-Atlantic Wholesale Market: VACAR

VACAR is a North American Electric Reliability Council (NERC) subregion that includes most of Virginia, North Carolina, and South Carolina, currently outside the PJM region. Figure II.4 charts wholesale prices for the region reported by Platts in *Megawatt Daily* for January 2003 through April 2004. Reported trading volume for the area's wholesale market is relatively thin, therefore, prices are based on few reported trades.

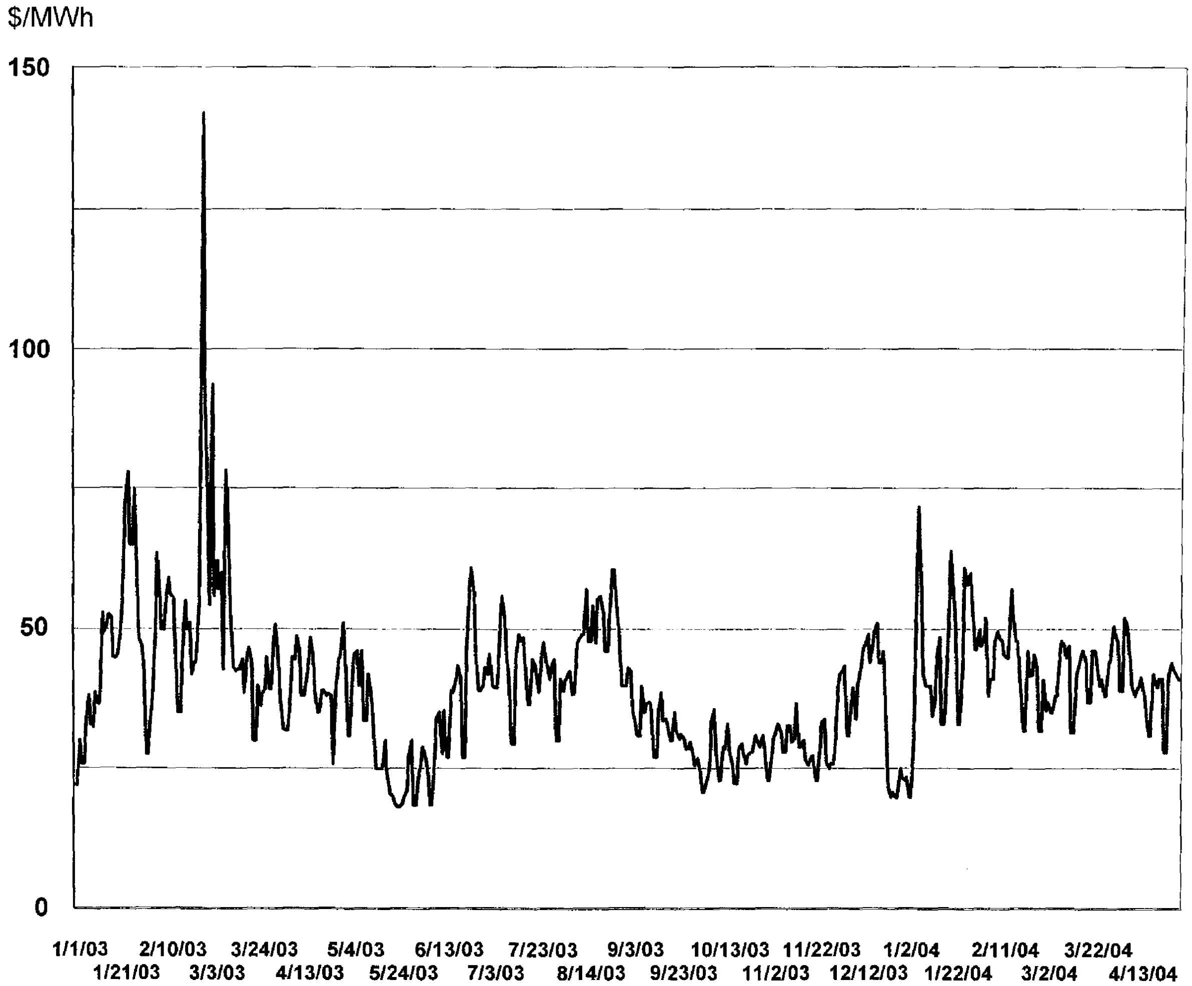

Figure II.4. *Platts* VACAR volume weighted average index prices, January 2003 through April 2004.
Data source: Platts McGraw-Hill, *Megawatt Daily*, 2003 and 2004.

Mid-Atlantic Retail Markets

Maryland

Retail access in Maryland 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 between three percent and 7.5 percent below rates in effect in June 1999 and had fixed Standard Offer Service prices for the generation supply portion of their bills for customers that do not choose an alternative supplier. This Standard Offer Service supplied by the utilities expires at different times by customer classes and utility company. The schedule for phase-out of Standard Offer Service is shown in Box II.1.

Box II.1. Standard Offer Service end dates by utility company.

- **Allegheny Power (APS)**: July 1, 2008 for residential customers; July 1, 2004 for non-residential customers.
- **Baltimore Gas and Electric (BGE)**: July 1, 2006 for residential customers; either July 1, 2002 (Schedule P C&I) or July 1, 2004 (remaining C&I).
- **Delmarva Power and Light (DPL or Conectiv)**: July 1, 2004 for residential customers; July 1, 2003 for non-residential customers.
- **Potomac Electric Power (PEPCO)**: July 1, 2004 for all customers.

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, will be based on bids received in a competitive bidding process to serve these non-choosing customers.

Residential customers of PEPCO and DPL/Conectiv began to receive bid-based Standard Offer Service beginning July 1, 2004 for customers who do not choose a competitive electric supplier. In April 2004, the Maryland PSC announced the results of the bidding process. According to the Maryland PSC, the bidding process involved 25 wholesale electric suppliers offering electric supply 4 to 5 times in excess of the load that was solicited. As a result of the bidding process, PEPCO residential customers will have the power supply portion of their bills increased by 26 percent and 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 will increase by approximately 13 percent; medium-sized commercial customer bills will increase between 25 to 30 percent; large-sized commercial customers bills will increase approximately 48 percent to 57 percent. Exact customer increases depend on customer class and individual usage. These increases are only for the generation component of the total bill.

DPL/Conectiv residential customers will have the power supply portion of their bills increased by 19 percent and average annual electric bills will increase approximately 12 percent (an increase of $130.80 for the average residential annual bill).

Generation supply prices for residential customers of Baltimore Gas and Electric Company continues to be frozen until July 2006 and residential customers of Allegheny Power will have frozen supply prices through 2008.

As summarized in Table II.1, nearly all the residential customer switching to alternative suppliers in Maryland has been in Potomac Electric Power's service area. However, the percentage of residential served by an electric supplier decreased from almost 16 percent in April 2003 to 11.6 percent in April 2004. Non-residential customers enrolled with an alternative supplier in Potomac Electric's service area also declined from just over 21 percent to 17.5 percent. There was no significant percentage of residential customers enrolled with an alternative supplier in any of the other three service areas. There was a significant increase in the percentage of non-residential customers choosing a supplier in Conectiv Power Delivery's area, from under two percent to over nine percent–however, that is a relatively low level overall. Only a very small percentage (less than one percent) of the non-residential customers had switched in Baltimore Gas & Electric's area and none had in Allegheny Power area in either year. Statewide, for April 2004, about three percent of all customers have chosen an electric supplier, less than three percent of all residential customers and 5.4 percent of the non-residential customers.

Table II.1. Maryland percentage of customers enrolled with an electric supplier

Utility	Residential		Non-Residential		Total	
	April 2003	April 2004	April 2003	April 2004	April 2003	April 2004
Allegheny Power	0%	0%	0%	0%	0%	0%
Baltimore Gas & Electric	0%	0%	0.5%	0.7%	0.1%	0.1%
Conectiv Power Delivery	0%	0.1%	1.6%	9.4%	0.2%	1.3%
Potomac Electric Power	15.7%	11.6%	21.4%	17.5%	16.2%	12.2%
Total	3.8%	2.8%	5.1%	5.4%	3.9%	3.1%

Source: Maryland Public Service Commission, for months ending April 25, 2003 and April 30, 2004.

As summarized in Table II.2, two areas had offers from alternative suppliers to residential customers, Potomac Electric Power and Baltimore Gas & Electric. No area in the state had an offer that was below the price-to-compare. Four areas had no offers at all. The one supplier in Baltimore Gas & Electric and Potomac Electric Power (PEPCO) service territories that was making the four offers was Pepco Energy Services, which was offering a “standard electricity” service, and 10 percent, 51 percent, and 100 percent “green electricity” offers. These offers were all above the price-to-compare. Pepco Energy Services is a wholly owned subsidiary of Pepco Holdings, Inc., which was formed by the merger between Pepco and Conectiv.

Table II.2. Competitive offers to residential customers in Maryland.

Utility	Number of Competitive Suppliers		Total Number of Offers from Competitive Suppliers		Number of Offers Below the Price-to-Compare	
	May 2003*	2004*	May 2003*	2004*	May 2003*	2004*
Allegheny Power	0	0	0	0	0	0
Baltimore Gas & Electric	1	1	2	4	0	0
Choptank Electric Cooperative	0	0	0	0	0	0
Conectiv Power Delivery	0	0	0	0	0	0
Potomac Electric Power	2	1	3	4	1	0
Southern Maryland Electric Cooperative	0	0	0	0	0	0

*2003 numbers from May 14, 2003. 2004 numbers for Allegheny Power, BG&E, and Choptank Electric Coop from May 2004, Conectiv Power Delivery last reported May 14, 2003, Potomac Electric Power from November 2003, and Southern Maryland Electric Coop from December 2003.
Source: Maryland Attorney General, 2003 and 2004.

District of Columbia

The Council of the District of Columbia passed legislation at the end of 1999 allowing the D.C. Public Service Commission to implement retail access. Retail access began for all customers in the District on January 1, 2001. By Commission order, there was a 7 percent reduction of PEPCO rates for residential customers and a 6.5 percent reduction of rates for commercial customers that was implemented in three phases in

2000 and 2001.[7] The District is also served by Potomac Electric Power (PEPCO), which completed the sale of all its generation plants by January 2001. PEPCO sold most of its electric power plants and other generation assets to Mirant Corporation. Mirant now owns four generating plants, a combined 5,256 MW, in the D.C. area. (Mirant filed for bankruptcy protection under Chapter 11 on July 14, 2003.) PEPCO also transferred ownership of two District of Columbia plants to its unregulated subsidiary, Potomac Power Resources, Inc. These two plants are operated by Mirant. PEPCO also sold its 9.7 percent interest in the Conemaugh Generation Station to Allegheny Energy, Inc. and PPL Corporation. In December 2000, PEPCO signed a four-year contract with Mirant Corporation to buy the power needed for its customers at prices below PEPCO's average cost of production. The Commission ordered PEPCO to distribute "divestiture sharing credits" to customers after PEPCO sold its generation assets and also a "generation procurement credit" for a share of the difference between the contract payment to Mirant and PEPCO's standard offer generation revenue.

Overall rate caps are in effect until February 7, 2007 for low-income customers and until February 7, 2005 for all other residential and commercial customers. PEPCO will provide generation service to its customers until February 2005. As part of the Commission's approval of the merger of PEPCO and Conectiv, distribution rates are capped at the February 7, 2005 levels for non-low-income customers from February 8, 2005 through August 7, 2007 and for low-income customers through August 31, 2009.

The Commission reported that, as of January 2004, two alternative suppliers–Pepco Energy Services (PES, an unregulated subsidiary of PEPCO Holdings, Inc.) and Washington Gas Energy Services (WGES, an unregulated subsidiary of Washington Gas)–were serving the District's residential sector. However, WGES is not accepting any new customers at the time. PES, WGES and BGE Homes are serving the District's non-residential (commercial) sector. PES announced in early May 2004 that the renewal rate for standard residential generation and transmission service will be over 41

[7]A chronology of Commission actions and other key events in D.C. retail access is at: www.dcpsc.org/customerchoice/whatis/electric/elec_restruc.shtm#Top

percent higher than the current rate for contracts that expire in July 2004. Rates for new residential customers were announced to be 59 percent higher than the current rate. PES customers have the option to return to PEPCO's capped prices (capped until February 2005), but they must inform PES in writing to terminate their contract–or they will automatically be renewed at the higher PES rate. The PES renewal rate is about 37 percent above the PEPCO average annual residential generation and transmission rate or the "price-to-compare" as defined in the District.

Table II.3 shows the current percent of customers and load served by alternative suppliers in the District. The percentage of both residential and non-residential customers served by alternative suppliers decreased somewhat from May 2003 to May 2004. The percent of residential customers dropped to under nine percent and under 15 percent for non-residential customers. However, the non-residential load (mostly commercial, in MWh) served by an alternative supplier remained above 40 percent.

Table II.3. Percent of customers and load served by alternative suppliers in the Dist. of Columbia.

	Residential		Non-Residential		Total	
Period \ Percent	Customers	Load (MWh)	Customers	Load (MWh)	Customers	Load (MWh)
May 2002	5.3%	5.3%	19.5%	55.0%	7.0%	48.5%
May 2003	11.2%	13.7%	16.5%	45.7%	11.9%	41.5%
May 2004	8.8%	10.6%	14.2%	41.2%	9.5%	36.7%

Source: District of Columbia Public Service Commission, June 2004.

New Jersey

As reported in the two previous years' reports, New Jersey had some activity early in the state's retail access program. One utility, Conectiv, reached almost 12 percent of the non-residential customers and almost six percent of residential customers being served by alternative suppliers, as reported for November 2000. Two other utilities had about six percent of the non-residential customers that had chosen an alternative, also reported for November 2000. About one year later, by October 2001, all customer switching by non-residential and residential customers had dropped to less than one percent for all companies in mid-2003. As Table II.4 shows, the percentage of customers choosing a supplier remained relatively low. For August 2004, residential customer percentages all remained at fractions of one percent and non-residential customer percentages, while much larger than those reported for July 2003, were all less than two percent. Because many larger non-residential customers have chosen an alternative supplier, for reasons that are explained below, the total state load (MW) being served by alternative suppliers was nearly 16 percent for August 2004.

The residential customer percentage for Jersey Central Power & Light Company (JCP&L) jumped from barely registering above zero in 2003 to over 11 percent as reported for June 2004. This was 107,339 residential customers in JCP&L's territory. However, JCP&L's "Green Pilot Program" accounts for the increase in the residential switching and the temporary percentage jump. This program was approved by the New Jersey Board of Public Utilities (the Board) in December 2002. The Board ordered JCP&L to requested competitive proposals from qualified bidders to supply green power to serve 200 MW of retail load or electric service for 150,000 residential customers, whichever is greater. The Pilot Program was set to run for ten months from August 1, 2003 through May 31, 2004. The winning prices from the bidding process were averaged with the prices obtained through the "Fixed Price" auction (described below), to determine JCP&L's system-wide rates. The low bidder was FirstEnergy Solutions Corp. with a bid of 5.444 cents/kWh to supply the entire program load. (FirstEnergy Solutions, is an affiliate of FirstEnergy Corp., which is also the parent company of JCP&L). When the results were averaged with the auction prices, the winning Pilot Program bid increased the price used to determine customer generation rates only by .307 percent – for a final price of 5.231 cents/kWh.

The Board had decided that if there was insufficient customer enrollment, the program allotment would be filled through random customer assignment where residential customers will be randomly assigned to the Green Pilot Program. Customers were given an opportunity to opt-out, if they so chose.[8] In October of 2003, the Board noted that only 5,700 customers volunteered for the program and 24,100 customers that were assigned to it chose to opt-out of the program. Because of the disappointing response, the program was allowed to expire on May 31, 2004, as scheduled.[9] The number of customers that opted out between October 2003 and May 31, 2004, when the program expired, was not provided. It is likely, however, the Pilot Program accounted for most of the 107,339 residential customers that were reported to have chosen an alternative supplier and explains why the percentage of customers dropped back to what it was for July 2003. (The number of customers dropped to just 340, of 931,940 residential customers in total, as reported in August 2004.)

Table II.4. Percent of New Jersey customers served by alternative suppliers.

Distribution Company	Residential			Non-Residential			Total		
	July 2003	June 2004	Aug. 2004	July 2003	June 2004	Aug. 2004	July 2003	June 2004	Aug. 2004
Conectiv	0.08%	0.07%	0.07%	0.31%	1.43%	1.43%	0.11%	0.24%	0.24%
JCP&L*	0.04%	11.52%	0.04%	0.04%	2.16%	1.88%	0.04%	10.46%	0.24%
PSE&G	0.05%	0.05%	0.05%	0.04%	1.64%	1.83%	0.05%	0.27%	0.29%
Rockland	0%	0%	0%	0%	0.26%	0.26%	0%	0.03%	0.03%
Statewide Total	0.05%	3.39%	0.05%	0.08	1.72%	1.76%	0.06%	3.18%	0.27%

Source: New Jersey Board of Public Utilities, July 29, 2003, June 17, 2004, and August 13, 2004.
*Includes residential customers in the JCP&L Green Pilot Program.

In February 2002, the New Jersey Board of Public Utilities (BPU) approved the results of the first Basic Generation Service (BGS) auction to meet the electric demands

[8]New Jersey Board of Public Utilities, Docket No. EX01110754, February 20, 2003.

[9]New Jersey Board of Public Utilities, Docket No. EO03050394, October 22, 2003.

of customers who have not selected an alternative electric supplier or who are dropped by a third-party supplier. More than twenty companies participated in the auction held on the Internet from February 4 to February 13, 2002. During this auction firms bid simultaneously to supply capacity, energy, and ancillary services to customers at a competitive price per kWh for the period of August 1, 2002 through July 31, 2003. This auction was conducted under the requirement of New Jersey's restructuring law that utilities facilitate competition of the supply of electricity to customers who have not switched companies under deregulation. The price results of the 2002 auction are shown in Table II.5. The auction was for full customer requirements, including energy, capacity, load following, ancillary services and transmission. Each utilities' load was broken down into slices or "tranches" that are approximately 100 MWs. The utilities still maintain customer services such as billing and metering.

The price results of the 2003 "Fixed Price" auction, held in February 2003, for BGS for small to medium-sized customers are also shown in Table II.5. Another separate auction was held this time to determine hourly- priced service for approximately 1,750 larger customers, where energy prices are based on PJM's hourly prices, the results of this "Commercial Industrial Energy Prices" (CIEP) auction are

Box II.2. The New Jersey Auction Process*

- Internet-based, simultaneous multi-round descending clock auction
- Basic Generation Service load for all four NJ electric utilities is auctioned simultaneously
- Auction is a "reverse auction" or procurement auction – where bids are offers to supply at a price (not to buy) – bid offers decline through auction
- Auction is conducted in a series of rounds, each with an announced starting and ending time
- Auction ends when the supply bids equal the BGS quantity needed for each of the four utilities
- Auction approval process:
    - auction results must be addressed by the NJBPU by the end of the second business day after the close of the auction
    - auction results must be accepted or rejected for all electric utilities in entirety or for none of them

*From presentation by Commissioner Frederick F. Butler, "Acquiring Electric Supply: An Overview of the New Jersey Basic Generation Service Auction Solicitation Process," April 29, 2004.

shown in Table II.6. Again, Internet auctions determined BGS for all the state's distribution companies. This was to provide BGS supply for the period from August 1, 2003 through May 31, 2004. The fixed price auction (for the smaller customers) concluded after 14 rounds of bidding and had 15 winning bidders sharing approximately 15,500 MW of load. The auction for hourly service or CIEP (for larger customers) had 15 rounds with eight bidders for the 2,500 MW of available load. New Jersey is currently the only state in the country using such an Internet-based auction procedure to determine prices for non-choosing customers. (Maine, as summarized in Section III, uses a competitive bidding process for its "standard offer" generation service.) Except for Rockland, all prices where somewhat higher than those determined in the 2002 auction.

Table II.5. Price results from the 2002, 2003, and 2004 "Fixed Price" auctions for small to medium-sized customers (cents/kWh).

	2002 Auction	2003 Auction		2004 Auction	
Term / Company	12 Month	10 Month	34 Month	12 Month	36 Month
Conectiv	5.12	5.260	5.529	5.473	5.513
JCP&L	4.87	5.042	5.587	5.325	5.478
PSE&G	5.11	5.386	5.560	5.479	5.515
Rockland	5.82	5.557	5.601	5.566	5.597

Source: New Jersey Board of Public Utilities, February 2003 and 2004.

A third BGS auction was held in February 2004 for service beginning on June 1, 2004. The results are again shown in Table II.5. The Board notes that on an annual basis, residential customers of PSE&G, Rockland Electric, and JCP&L will have small decreases, ranging from 0.5 percent to 1.5 percent. Conectiv residential customers will see a slight increase of 0.7 percent. The 2004 auction was similar to 2003, with two simultaneous multiple round auctions, a fixed price auction for small and medium sized customers and one for hourly-priced service for about 1,750 of the state's largest electric customers (CIEP auction). According to the New Jersey Board, for the fixed price customers, 33 percent of the energy will be for a 12 month commitment and 33 percent will be for 36 months – with the balance of the fixed price demand being met under contract until May 2006. The Board required participation in the hourly auction for all commercial and industrial customers with a peak load share of 1500 kW and greater (which added about 128 accounts to the CIEP class in the 2004 auction). The Board allowed other commercial and industrial customers to volunteer to participate in the hourly auction–approximately 100 customers volunteered to participate statewide. The Fixed Price auction ran from February 2, 2004 to February 10 and had 71 rounds of bidding with 12 winning bidders. The hourly or CIEP auction also began on February 2, 2004 and ended on February 6 after 52 rounds of bidding with six winning bidders. The results of the hourly or CIEP auction for 2004 are also shown in Table II.6.

Table II.6. Price results from the 2003 and 2004 "Commercial Industrial Energy Prices" (CIEP) auctions for large customers (Dollars per MW-day).

	2003 (10 months)	2004
Conectiv	56.10	49.90
JCP&L	65.25	54.98
PSE&G	60.00	52.01
Rockland	59.80	57.96

Source: New Jersey Board of Public Utilities, February 2003 and 2004.

The approximately 1,750 larger CIEP customers pay the auction price, plus an administrative fee and an energy price based on PJM's hourly prices. Unless, of course, these customers make provisions with a supplier of their own choice. In contrasts, the Fixed Price customers pay the auction-based fixed price result if they do not choose a supplier. As of December 31, 2003, 56 percent of the CIEP customers switched to an alternative supplier or 76 percent of the total CIEP load.[10]

On August 1, 2003, the auction-determined generation prices translated directly to the rates customers pay, since the transition period ended and the rate caps and discounts ended. The New Jersey Board of Public Utilities determined the post-transition, non-generation portion of rates for customers in July 2003. Beginning August 1, 2003, excluding the BGS portion, all Conectiv customer classes had an average rate increase of approximately 4.7 percent. The estimated average BGS increase for all fixed-price customer classes is about 3.4 percent, resulting in a total rate increase of 8.1 percent. The average residential customer had an increase of approximately 6 percent on their monthly bill (the average residential bill would increase from $85.77 per month to $90.93 per month). This includes deferred balances accrued by Conectiv during the transition period when the rate cap was in effect and the company could not recover all of its costs incurred to supply its customers (as New Jersey's restructuring law allows recovery after the four-year transition period). The Board also determined that Rockland's (a company that also had deferred balances) rates for the average residential customer would increase by 15.4 percent. This includes the estimated 11.3 percent increase in BGS charges and resulted in a monthly bill increase from $85.21 per month for the average residential customer to $98.36 per month. The Board also authorized PSE&G (again with deferred energy costs) an increase of approximately 15 percent for the residential customer class. The Board modified the rate design in a proposed settlement to assure that the majority of residential customers receive no more than a 15 percent increase on an overall annual basis, including BGS prices. For Jersey Central Power & Light, the Board approved an average annual increase in rates of approximately 3.5 percent for the typical residential customer. All these rate increases became effective August 1, 2003. The BGS fixed price portion will be adjusted again to reflect the 2004 auction results.

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[10]Presentation by Commissioner Frederick F. Butler, "Acquiring Electric Supply: An Overview of the New Jersey Basic Generation Service Auction Solicitation Process," given at *Post 2006 Symposium*, Chicago, IL, April 29, 2004.

Pennsylvania

Pennsylvania had, at one time, the most active retail access program in the country. In early 2000, PECO Energy alone, then the most active service area in the state (and the country), had 29 offers being made to residential customers–about 20 of which were below the price-to-compare. Every service area in the state had at least two offers to residential customers that were below the price-to-compare. This changed dramatically by mid-2001, when many competitive suppliers reduced their offerings to customers or left the market entirely.

Table II.7 shows that in May 2003, the entire state had only one offer below the price-to-compare and none in 2004. In May 2002, the state had three such offers, all in PECO Energy's service territory. The number of competitive suppliers in each company's territory remained about the same and, with the exception of PECO Energy's area, the total number of offers from these suppliers also remained about the same. There offers were overwhelmingly for "green power" where at least some portion of the generation uses a renewable energy source. Of the 34 total offers in the state from competitive suppliers in July 2004, all but three had some portion of renewable resources use (the three non-renewable offers were all in PECO Energy's territory).

The 2003 Performance Review summarized an analysis by the PJM MMU that concluded that there was an exercise of market power in PJM's capacity credit markets during the first quarter of 2001,[11] and included additional explanation and the findings from an investigation by the Pennsylvania Public Utility Commission and the Pennsylvania Attorney General. The capacity credit market's problems combined with the energy market prices in early 2001 was clearly a significant factor that caused the drop-off in retail market activity in Pennsylvania and other PJM states. The highest "shopping credit" or price-to-compare for generation service in Pennsylvania at that time was in PECO Energy's territory, at 5.67 cents/kWh.[12] When energy prices reached over

[11]PJM Interconnection, L.L.C., Market Monitoring Unit, "Report to the Pennsylvania Public Utility Commission, Capacity Market Questions," November 2001.

[12]Current annual average price-to-compare for regular residential service.

$50/MWh, as it averaged during December of 2000 and again in August of 2001, adding $10/MWh for capacity[13] would place the total cost over $60/MWh or 6 cents/kWh, well above the fixed PECO Energy price-to-compare at that time and about the level of the 2004 price-to-compare (see Table II.7 for the 2004 price-to-compare by company). Alternative suppliers that need to secure capacity to serve a retail load in PJM would face a loss of at least 0.33 cents/kWh for each kilowatthour sold. Even when energy prices are in the $30 to $40/MWh range as they averaged from January through May of 2001, the margin for a gain would be very thin and risky given the price volatility in both the energy and capacity markets. This also leaves very little room for marketing costs, administrative costs, cost of risk management, or an adequate profit. The retail markets have not returned to those pre-2001 levels of activity.

Figures II.5, II.6, and II.7 plot the customer switching activity for Pennsylvania back to the first quarter of retail access in the state for residential, commercial, and industrial customers, respectively. The decrease that occurred in 2001 in retail market activity can be seen in all three customer groups. Residential switching continues to decline or remain flat, with all but Duquesne Light and PECO Energy now below one percent of customers with an alternative supplier.

There have been two assignments of residential customers in the PECO Energy area. The affect of the first assignment can be seen in the April 2001 percentage. While it drifted downward after the initial assignment, it dropped considerably in 2002 when the main supplier returned its customers back to PECO Energy (180,000 customers of NewPower, an affiliate of Enron, ceased to be a competitive supplier and transferred its customers back to PECO Energy in April 2002). The second assignment of residential customers in PECO Energy's territory can be seen in the January 2004 percentage, when it jumped back to about 20 percent of customers. It declined

[13]The PJM Market Monitoring Unit in its report on the 2000 market issued in 2001, states that "[a] maximum capacity market price of $160/MW-day is equivalent to a net energy price differential of $10/MWh for a 16-hour forward market standard energy contract."

somewhat in April 2004, down to 17.7 percent. Without the assigned customers, PECO Energy residential customer switching for April was four percent.

Table II.7. Competitive offer summary for Pennsylvania residential customers.*

Utility	2004 Price-to-Compare (¢/kWh)	Number of Competitive Suppliers		Total Number of Offers from Competitive Suppliers		Number of Offers Below the Price-to-Compare	
		May 2003	July 2004	May 2003	July 2004	May 2003	July 2004
Allegheny Power	3.871	2	1	3	2	0	0
Duquesne Light	5.83	3	2	4	3	1	0
Met Ed	4.588	2	2	3	3	0	0
PECO Energy**	6.17	6	6	7	14	0	0
Penelec	4.592	2	2	3	3	0	0
Penn Power	5.273†	2	2	3	3	0	0
PPL Utilities	4.84	2	2	3	3	0	0
UGI	5.803†	2	2	3	3	0	0

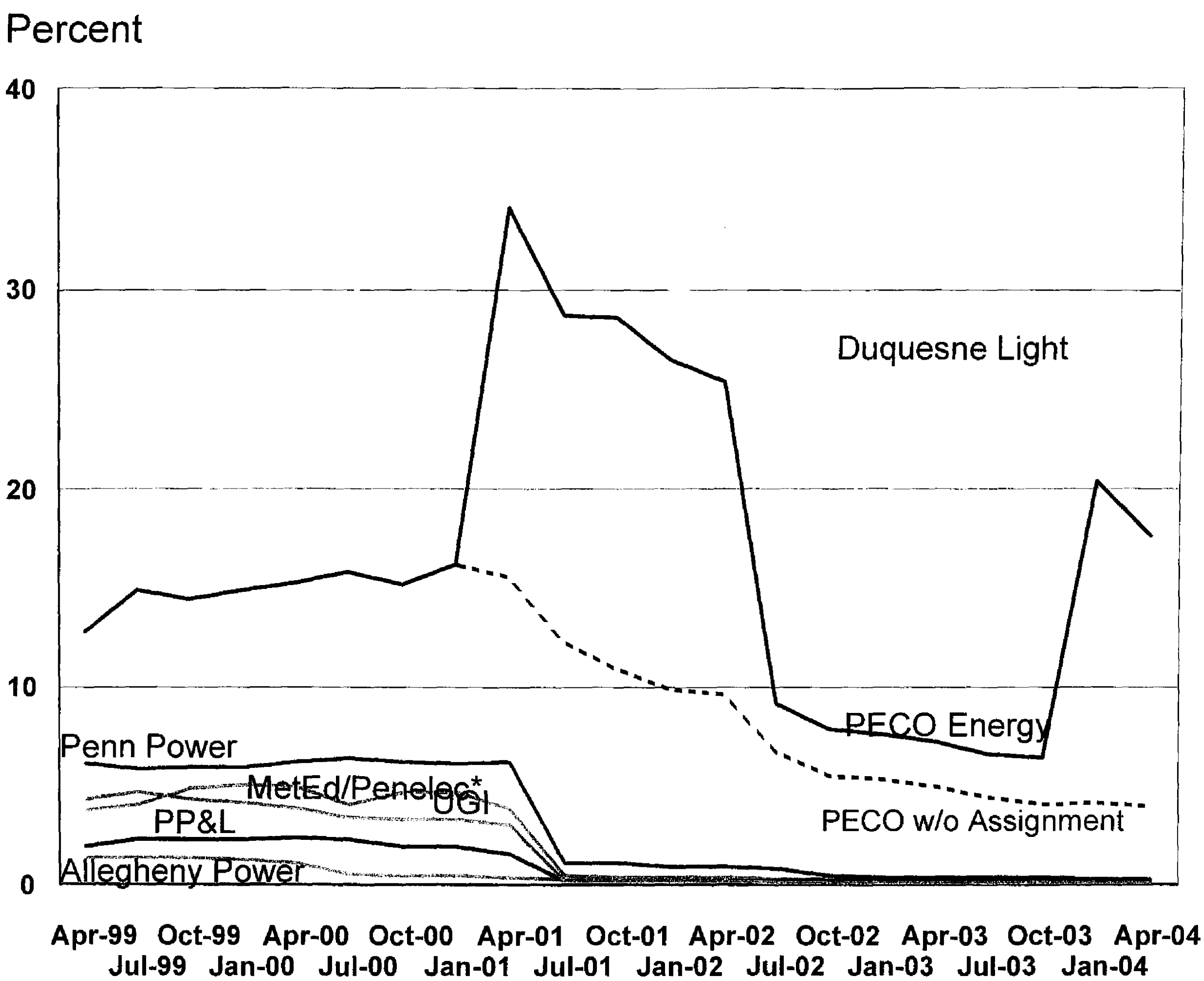
*For Regular Residential Service.
**Does not include the "Market Share Threshold Program Service" (MST), which for 2004 is priced at 0.09 cents/kWh less than PECO Energy's Price-to-compare, or at about a 1-1/2 percent discount. This is only available to preselected MST customers, not available to new customers.
†Price for 1,000 kWh, actual price depends on usage.
Source: Pennsylvania Office of Consumer Advocate, May 2003 and July 2004.

With commercial customers (Figure II.6), all areas, again except Duquesne Light and PECO Energy, are at or below one percent – PPL is reported at one percent and Allegheny Power, Met Ed/Penelec, Penn Power, and UGI are reported at 0.1 percent. Duquesne Light is at just above 20 percent and PECO Energy, with the assignment of its commercial customers, is at 38.5 percent. Without the customer assignment, PECO Energy commercial customer switching drops to 9.5 percent.

Industrial customer switching in Pennsylvania (Figure II.7), for all areas, except Duquesne Light, are well below five percent. Nearly 40 percent of the customers in Duquesne Light's territory are with an alternative supplier.

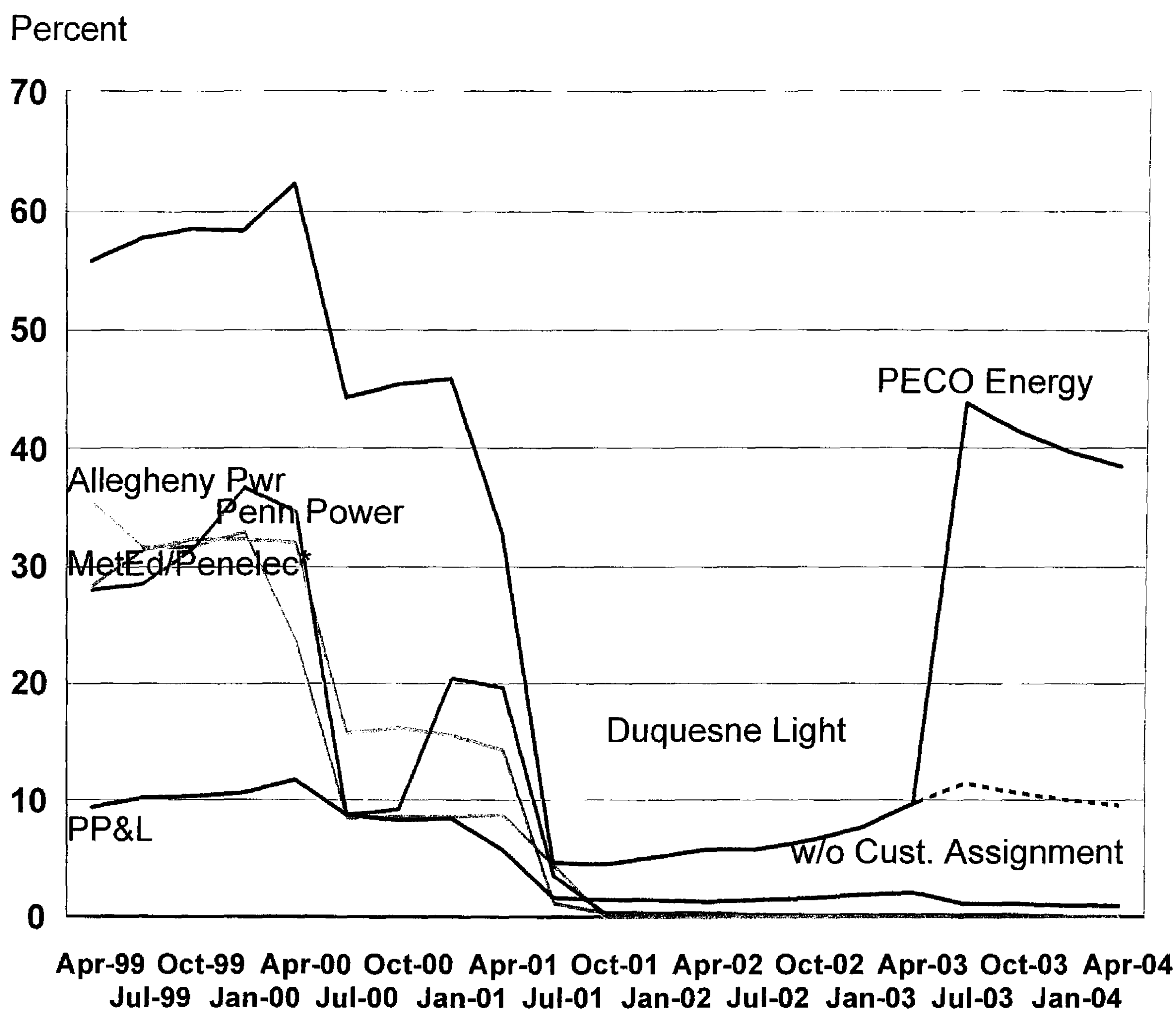
Figure II.8 shows the percent of load served by alternative suppliers in the state in April 2004. Only Duquesne Light and PECO Energy have a sizable percentage of their total load served by alternative suppliers (with Duquesne Light at about one-third of its total load). Also, Met Ed/Penelec industrial load is above 20 percent.

Figure II.9 shows the decline in customer switching in the state in terms of total load. The peak was reached in April of 2000, at 8,320 MW, fell to 5,509 MW in July 2000, then fell again to 2,039 MW in July 2001. Since then, total load served by an alternative supplier has climbed back to over 3,000 MW in 2004 (2,326 MW in April 2004 without the PECO Energy assigned residential and commercial load). This is about 10 percent of the state's total load.



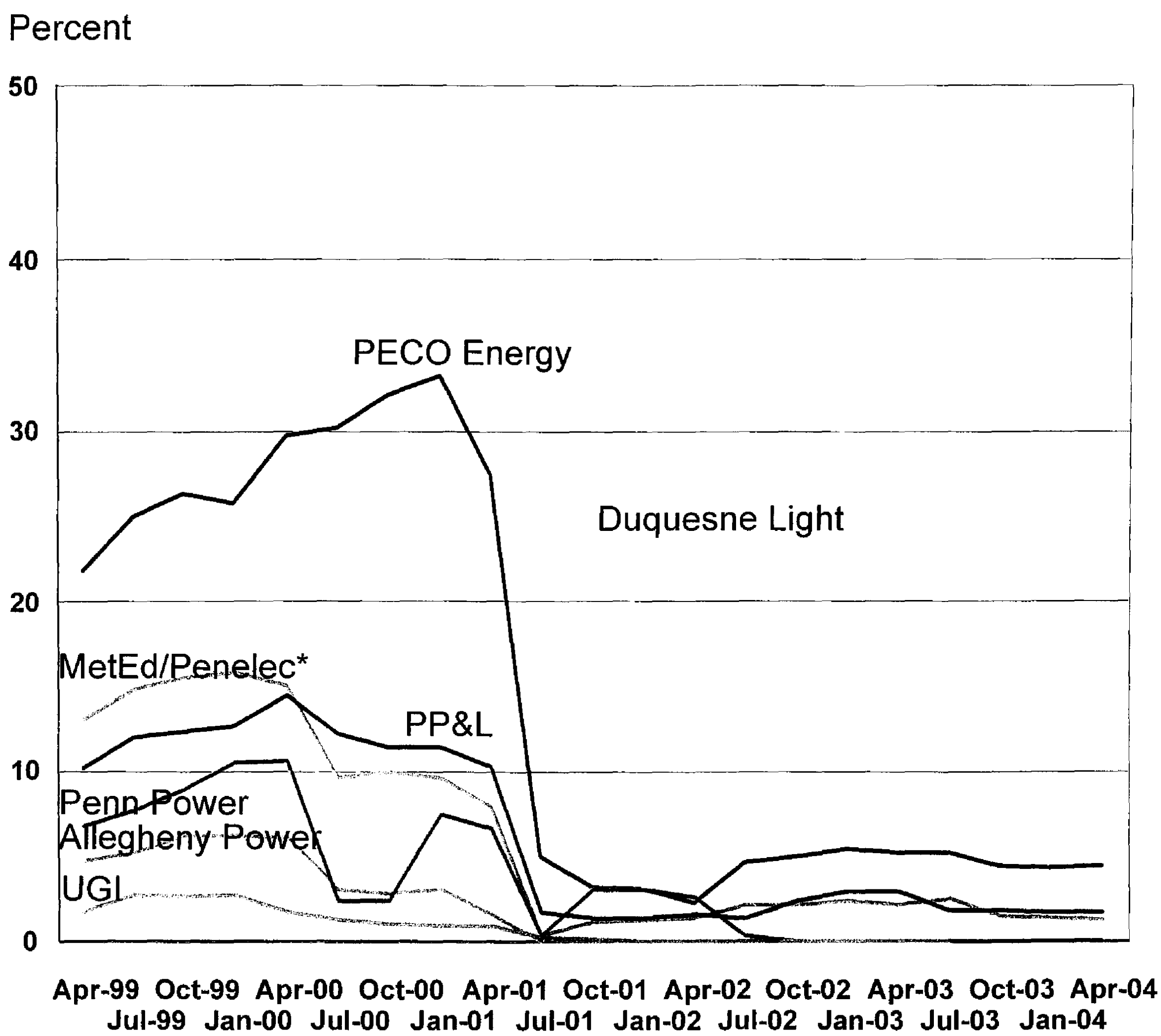
*MetEd and Penelec were formerly part of GPU.
Data Source: Pennsylvania Office of Consumer Advocate

Figure II.5. Percent of residential customers served by an alternative supplier in Pennsylvania.



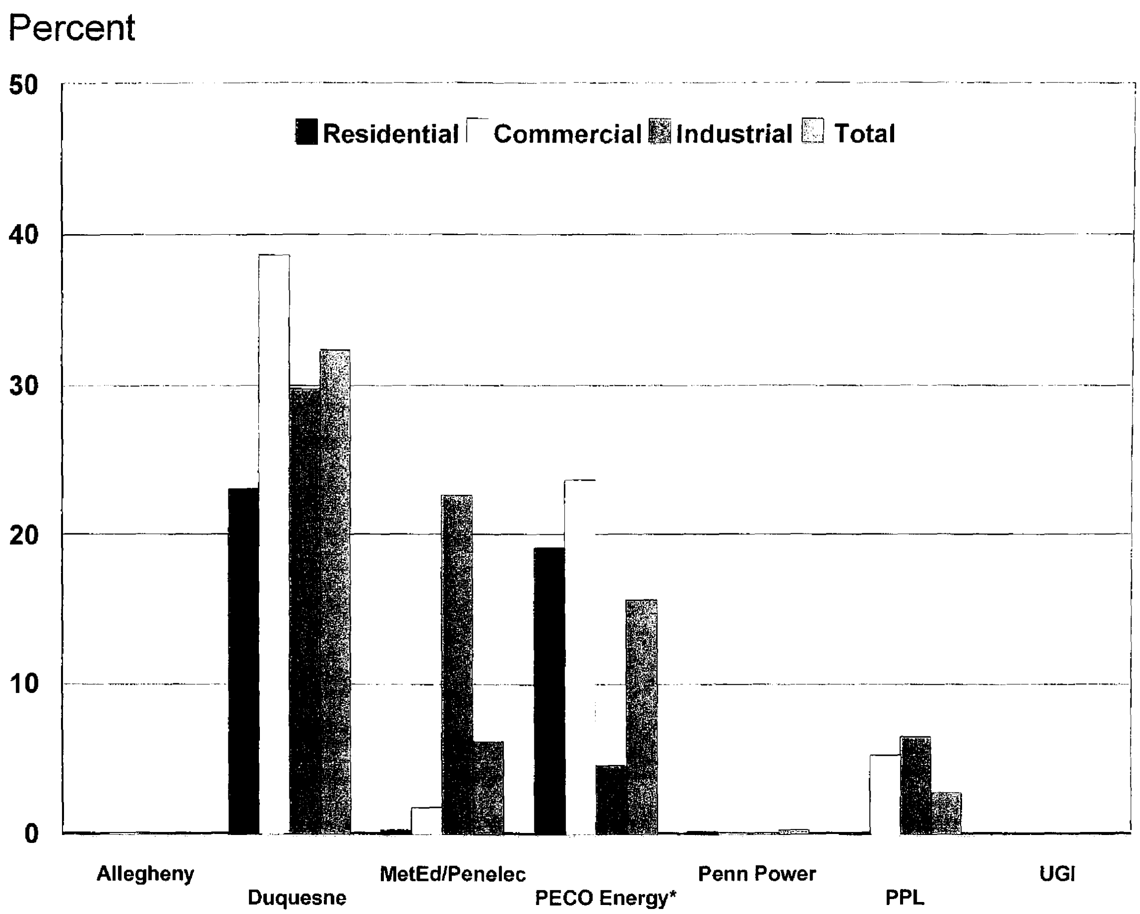
*MetEd and Penelec were formerly part of GPU.
Data Source: Pennsylvania Office of Consumer Advocate

Figure II.6. Percent of commercial customers served by alternative suppliers in Pennsylvania.



*MetEd and Penelec were formerly part of GPU.
Data Source: Pennsylvania Office of Consumer Advocate

Figure II.7. Percent of industrial customers served by alternative suppliers in Pennsylvania.



*PECO numbers include 14.7% of residential customer load and 12.9% of commercial customer load assigned to "Market Share Threshold Program."
Data Source: Pennsylvania Office of Consumer Advocate

Figure II.8. Percent of customer load served by alternative suppliers in Pennsylvania, by utility company in April 2004.

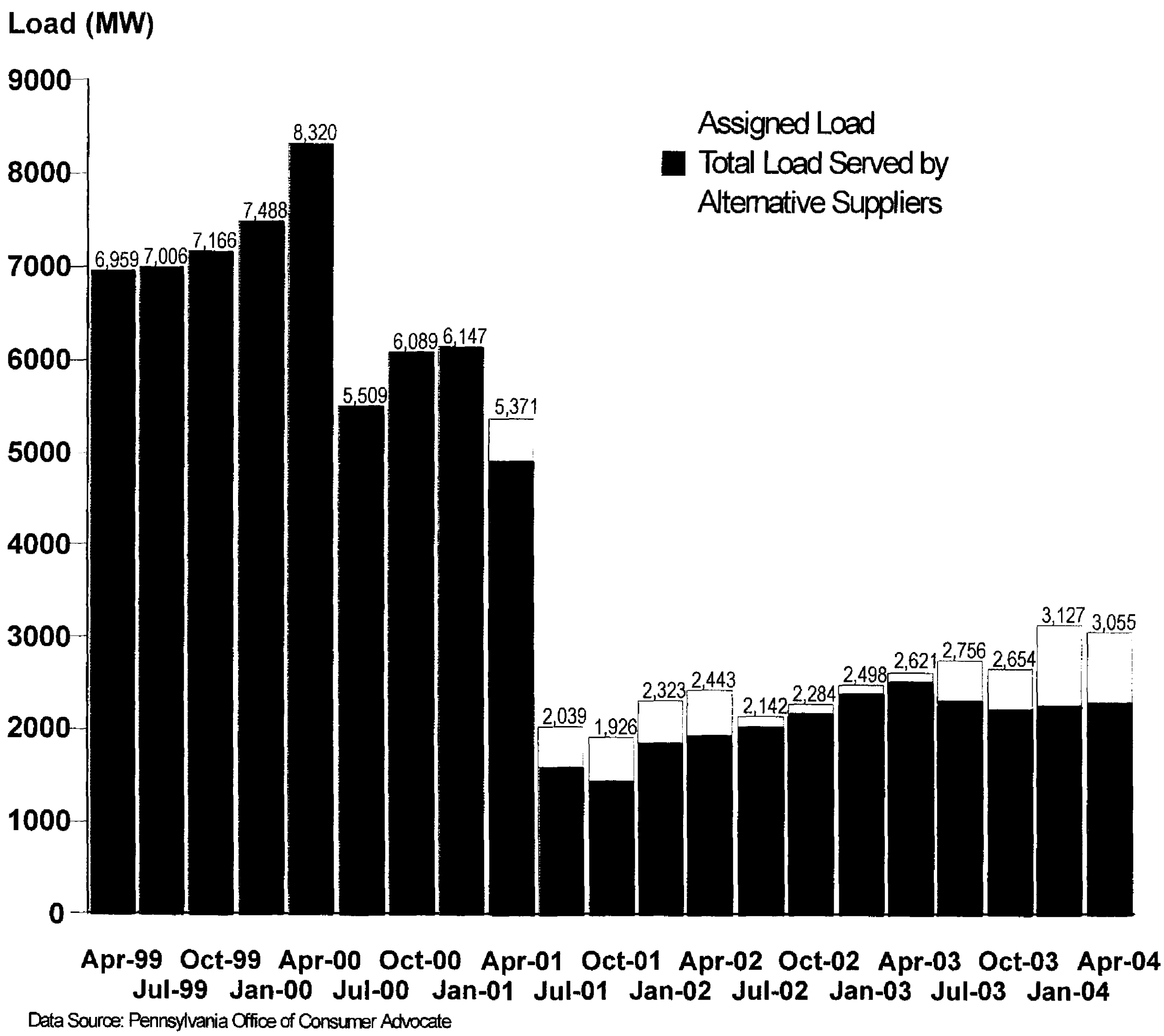


Figure II.9. Total customer load served by alternative suppliers in Pennsylvania.

Section III
New England

Wholesale Market and ISO New England

The New England Power Pool (NEPOOL) was created in 1971 from the integration of most of New England's utilities and municipal systems. This includes all of Connecticut, Massachusetts, New Hampshire, Rhode Island, Vermont and the southern portion of Maine.[1] NEPOOL was created primarily to enhance the region's system reliability in response to the northeast's 1965 blackout. After FERC Order 888 was passed, that mandated transmission open access, NEPOOL chose to contract with ISO New England, Inc. to meet the operational and organizational structural requirements of an ISO under the FERC Order. ISO New England was created and in 1997 approved by FERC to operate the six-state New England region's bulk electric power system and wholesale electricity markets. In March 2004, FERC conditionally approved ISO New England as a Regional Transmission Organization (RTO). Currently, NEPOOL's responsibilities include the Open Access Transmission Tariff (OATT) and the market rules for the exchange of wholesale power. ISO New England currently administers OATT, and operates the transmission system, the dispatch of generation, and the electricity markets.[2]

ISO New England has interconnecting transmission lines connecting it to New York State and Quebec and New Brunswick in Canada. These lines are for the sale and purchase of electricity between the regions and for reliability purposes. From ISO

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[1]Northern Maine is not part of NEPOOL and is not directly connected to the rest of Maine and New England. However, northern Maine is electrically connected through transmission lines through New Brunswick that are part of the transmission system that interconnects the northeastern U.S. and central and eastern Canada.

[2]This description of responsibilities for NEPOOL and ISO New England is from 106 FERC ¶61, 280, "Order Granting RTO Statue Subject to Fulfillment of Requirements and Establishing Hearing and Settlement Judge Procedures," March 24, 2004.

New England's description, the power system and wholesale market serves about 6.5 million customers in an area with a population of 14 million people. The total energy market value is $7 billion, with $1.8 billion cleared in the spot market. There are over 350 generating units and over 8,000 miles of high-voltage transmission lines. New England system is a summer peaking system with peak demand in summer typically between 19,000 MW and 23,000 MW and winter peak demand between 17,000 MW and 19,000 MW. On August 14, 2002 a peak demand of 25,348 MW was reached, which is the current record peak demand for the region. The normal weather summer peak has increased by 20 percent over the last ten years.

ISO New England began managing the region's restructured wholesale power markets in May of 1999. In March 2003, the region began implementing its own version of a wholesale Standard Market Design. This includes using Locational Marginal Pricing (LMP) for transmission congestion management, day-ahead and real-time energy markets, and using monthly and long-term Financial Transmission Right (FTR) auctions to allow market participants to hedge against the possibility of paying transmission congestion charges under LMP in the day-ahead market.

The New England power market trades about 75 percent of its electricity under bilateral contracts and 25 percent in the real-time market.

The ISO currently has about 31,000 MW of total capacity and maintains an operating reserve margin of about 1,700 MW. The region is expecting to add approximately 3,500 MWs within the next year (as of May 2003). The region's electricity supply has increased by about 40 percent within the past five years.

Dependance on Natural Gas

According to ISO New England, approximately 29 percent of the total megawatt hours produced in the region in 2002 was from natural gas generators, this was up considerably from 13 percent in 2000. Nuclear and coal generated 26.6 percent and 12.3 percent, respectively, in 2002.

This increasing use and reliance on natural gas for power generation is causing concern in the region. ISO New England issued a White Paper that examined current and future use of natural gas for power generation and natural gas supply availability in the region.[3] The study notes that the recent power plant building boom in the region is expecting to add nearly 10,700 MW of new capacity between 1998 and 2005–all of it natural gas-fired capacity. It is expected that 41 percent of New England's total electricity production will be gas-fired in 2003 and could reach 49 percent by 2010. The study notes that, except for Texas,[4] "New England is by far the most dependent region in North America on natural gas for power generation." In addition, because of insufficient pipeline capacity in the region, studies by ISO New England indicate that approximately 2,800 MW to 3,900 MW of gas-fired generation would be unserved by pipelines during a peak winter day as soon as by the winter of 2004/2005. This is due to the coincident natural gas and electric generation requirements during the heating season.

This problem is particularly acute in the Boston area "load pocket." The Boston subarea is expected to have 65 percent of its electricity generated by natural gas in 2003 and is forecasted to increase to 80 percent by 2010. If a single power plant that is critical to the sub-area's electric supply, the Salem Harbor plant, is converted to natural gas, that subarea's electricity generated with natural gas could rise to 94 percent. Salem Harbor is a 745 MW coal- and residual fuel oil-fired power plant with four units located about 15 miles north of Boston; it accounts for about 21 and 23 percent of the Boston area's current winter and summer generating capacity, respectively. Because of its fuel use and location, it is subject to state and federal environmental regulations for nitrogen oxides, sulfur dioxide, carbon dioxide, and mercury emissions. Compliance options include switching to natural gas use or retiring the plant. Because transmission

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[3]ISO New England Inc., "Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Electric Load Pocket," prepared by Levitan & Associates, Inc., July 1, 2003.

[4]Texas (ERCOT region) is 44 percent natural gas-fired generated, according to Energy Information Administration numbers presented in Table 3 of the White Paper on page 13. They also note that Texas is in a region that has ready and ample natural gas supplies, while New England must rely on supply basins that are between 750 to 4,000 miles away.

constraints limit the amount of power that can be sent from outside the subarea, either of these options would have a major impact on the subarea's fuel diversity and supply resources.

Blackout of 2003

According to ISO New England, the blackout of August 14, 2003 created the system's "most challenging conditions in more than 30 years of operation."[5] However, the impact was limited to small areas in Springfield and the Berkshires Massachusetts and in southwest Connecticut and northwest Vermont. The ISO believes that New England escaped further impact because of automatic relays that shut down its links with New York, system operators who were able to stabilize the system, adequate generation within the system to be self-sufficient once isolated from the rest of the Eastern Interconnection, and close coordination between the ISO and utilities to restore power to the effected areas. While the ISO believes it generally preformed well during the crisis, they made policy recommendations to ensure future reliability and make it less likely that there will be a reoccurrence of the blackout. There specific recommendations are similar to the U.S. - Canada Power System Outage Task Force discussed in Section I. These include national and regional standards, restoration plans, and further analysis.

The January 2004 "Cold Snap"

Another significant challenge that the ISO recently faced occurred during severe cold temperatures that affected the region January 14 through 16, 2004. ISO New England also issued a report examining this event in detail.[6] The severe weather caused unprecedented winter demand on both the electricity and natural gas systems.

[5] ISO New England, "Performance of the New England and Maritimes Power Systems During the August 14, 2003 Blackout," February 2004.

[6] ISO New England Inc., Market Monitoring Department, "Interim Report on Electricity Supply Conditions in New England During the January 14 - 16, 2004 'Cold Snap,'" May 10, 2004.

New record winter peaks were set on January 14 and reset again the next day at 22,817 MW. According to the ISO, at the peak hour on January 14, the hourly real-time price rose to nearly $1,000 per MWh (there is a $1,000 per MWh bid cap) and day-ahead natural gas prices in the New England system increased to nearly ten times their normal levels. The report concluded that the regions electricity system performed well and the ISO was able to avoid supply interruption despite record winter peak electricity demand and unexpected generator outages. They also found no evidence of anti-competitive behavior by generators. They did find however, that the "Cold Snap" of January 2004 did highlight vulnerabilities of the New England power system, especially in the natural gas pipeline network's capacity limitations.

Echoing the concerns raised in the July 2003 Levitan & Associates report done for the ISO, mentioned above, the report noted the region's dependence on natural gas for electric power generation and how it can cause problems during periods of extremely cold temperatures. They point out that most of the new generation capacity added in New England since 1990 is fueled by natural gas and that currently over 30 percent of winter capacity consists of gas-only units and another 20 percent is gas-capable dual-fuel units. On January 14, there was 8,927 MW of unavailable capacity, gas-capable units were 81 percent (7,238 MW) of that total unavailable capacity and the largest category of outages by fuel type.

Their finding of no evidence of anti-competitive behavior by generators is based on analyses conducted by the ISO's own Market Monitoring Department. They examine whether there was any economic or physical withholding and found no evidence of anti-competitive behavior. Price offers from gas-fired units may have increased sharply, they argued, but this was consistent with gas market conditions at the time and was consistent with expected supplier market behavior under the circumstances. Using several tools to analyze market behavior during this period, including pivotal supplier and competitive benchmark analyses (discussed below), they found no instances of improper or anti-competitive behavior on the part of suppliers during this cold weather period.

FERC's Office of Market Oversight and Investigations (OMOI) also conducted an investigation of the January events and came to similar conclusions.[7] In this case, they examined both the electricity and natural gas markets. They believed that the natural gas markets in the region responded well under the circumstances and found no manipulation in gas market trading (natural gas spot prices spiked on January 15th, averaging $63 and a few trades as high as $75/MMBtu). On the electric side, they concluded that electric markets had no service interruptions, customers were largely protected from the price spikes in spot power market due to forward contracting (the real-time market price peaked at $920 per MWh on Jan 14, for one hour), natural gas sales by generators complied with market rules, the price spike were not the result of physical or economic withholding or manipulation, and there was no misbehavior or exercise of market power.[8] They also noted that plant mechanical and fuel-related outages reached 8,927 MW, with 81 percent being gas-capable units. OMOI also noted that 36 percent of the outages were fuel related and that half of fuel outages involved generators selling firm natural gas into the spot market. They note that natural gas still managed to serve 27 percent of the load.

The Connecticut Attorney General issued a press release[9] stating that he filed comments with ISO New England, disputing the ISO report's conclusion that no significant flaws in the region's power system were involved the cold snap. The Attorney General stated:

> Most notably, ISO-NE should reconsider its preliminary conclusion that 'New England's electricity system performed well in most respects.' To the contrary, the evidence in the interim report demonstrates that the market

[7]William F. Hederman, Office of Market Oversight and Investigations, Federal Energy Regulatory Commission, "Investigation of New England Gas-Electric Market Events January 13-16, 2004," presentation at the New England Conference of Public Utilities Commissioners, Brewster, MA, May 24, 2004.

[8]Conclusions from Hederman, slide 3.

[9]Connecticut Attorney General's Office," Attorney General Disputes Findings of ISO-NE Study On Near Blackout During January Cold Snap," Press Release, July 6, 2004.

rules in place during the cold snap and ISO-NE's administration of those rules were not adequate to protect Connecticut's electricity consumers from the threat of rolling blackouts on the coldest night of the year and, in fact, imperiled the health and safety of millions of New England residents. During such times of extreme cold, the availability of reliable electricity is, first and foremost, a matter of public safety.

Among several criticisms of the ISO report's findings and methods, the Attorney General pointed to the fact that power suppliers shut down their plants and sold their natural gas into the spot market rather than use it to generate electricity at a critical time. In addition, the Attorney General believed that the ISO failed "to determine if generators took advantage of the cold snap to manipulate the wholesale electricity market or engage in anti-competitive behavior."

New England Wholesale Prices

ISO New England's monthly average prices are charted in Figure III.1. This is the monthly average, on-peak monthly average, and off-peak monthly average prices for May 1999 through May 2004.[10] The impact on prices from the hot weather in late July and early August of 2001 can be seen and, as seen with most other power markets, the impact from the higher natural gas prices in early 2003 and during the "cold snap" of January 2004. The monthly averages show a significant impact in January 2004, increasing monthly averages to the highest levels since 2000. As seen in other wholesale power markets, the highest annual peaks of the last two years have occurred in the winter months.

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[10]For May 1999 through February 2003, prices are the monthly average clearing price, monthly average on-peak price, and monthly average off-peak price. For March 2003 through May 2004, the period of ISO New England's Standard Market Design, prices are the average real-time LMP (the average hourly real-time hub or zone LMP for the month), on-peak LMP (the average real-time hub or zone LMP for peak hours in the month, where peak hours are hours ending 8:00 AM to 11:00 PM Monday through Friday excluding holidays), and off-peak LMP (average real time hub or zone LMP for the off-peak hours in the month).

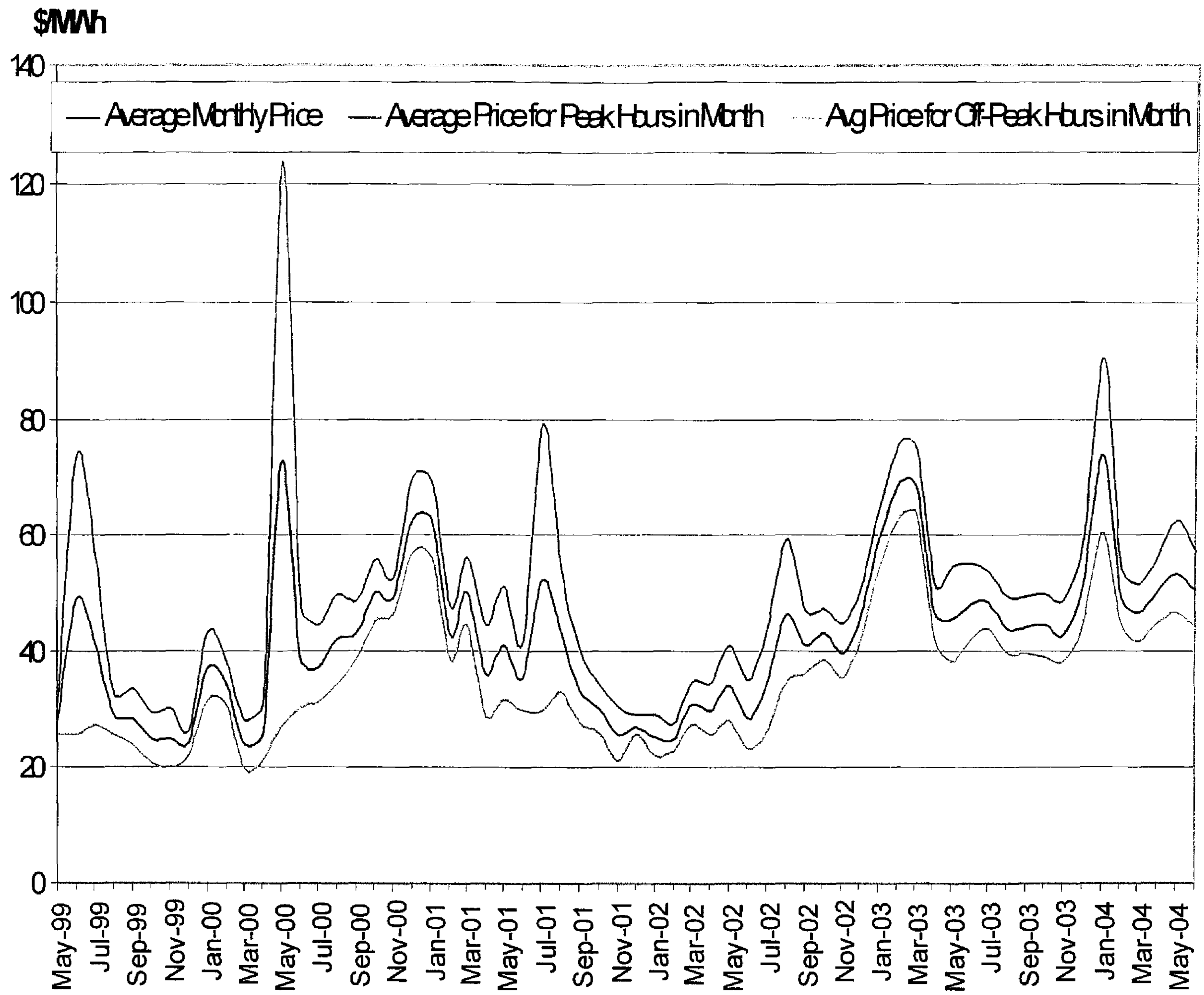

Figure III.1. Average monthly, average monthly peak, and average monthly off-peak prices in ISO New England, May 1999 through May 2004.
Source: ISO New England, June 2003 and July 2004.

Figure III.2 plots wholesale prices for deliveries into the New England Power Exchange (operated by ISO New England) for January 1, 2003 to March 10, 2003 and for the Massachusetts Hub price (from Platts, *Megawatt Daily*), located in central Massachusetts, for March 1, 2003 through April 30, 2004. This is a daily volume weighted average index of peak hour prices (in dollars per MWh). Again, the impact from natural gas prices can be seen in this daily index in early 2003 and 2004. The peak for January 2004 was on January 15, 2004 (during the "cold snap"), at $315 per MWh. The index stayed above $70 from January 7 through February 2, 2004.

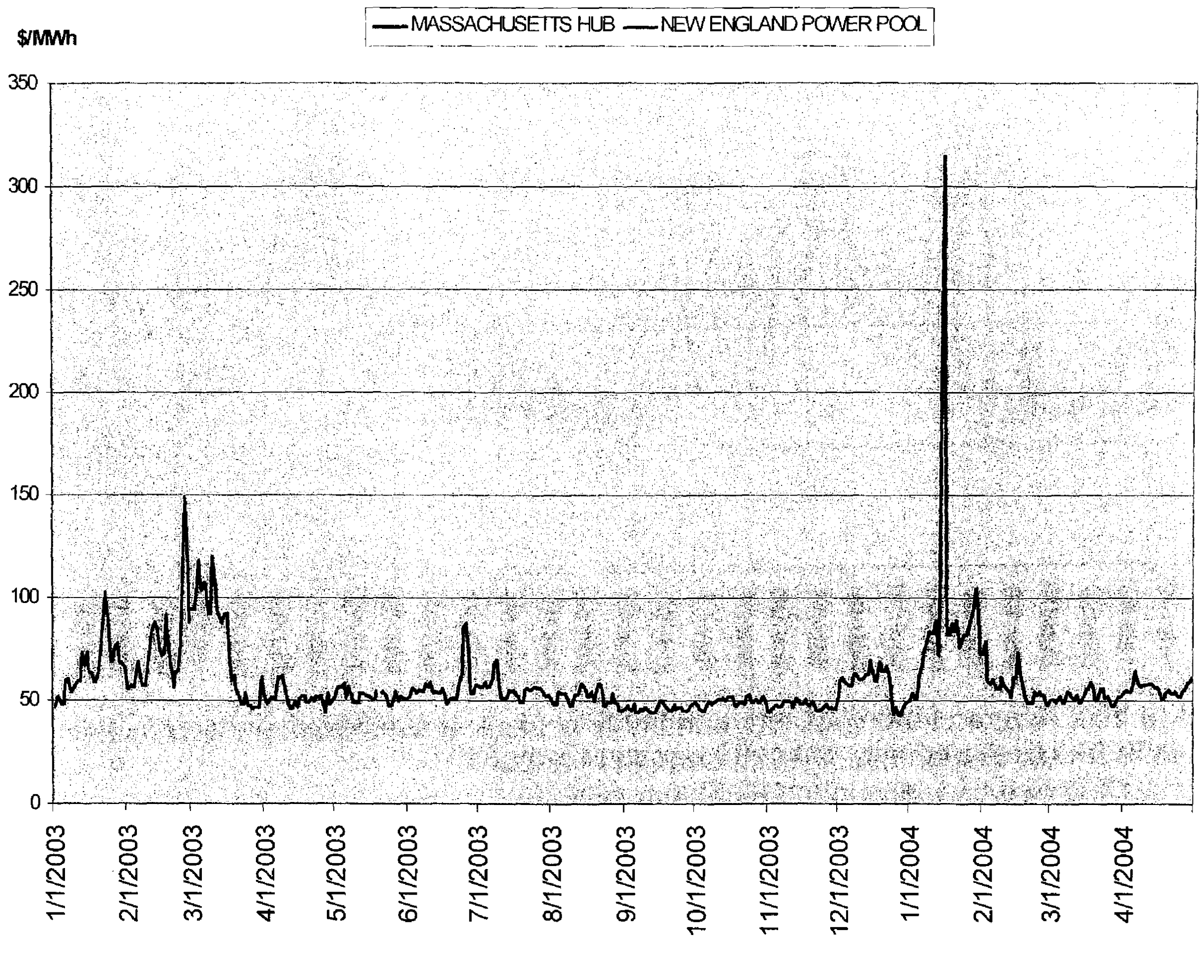

Figure III.2. New England wholesale volume weighted average index, January 2003 through April 2004 ($/MWh).
Source: Platts, Megawatt Daily, 2003 and 2004.

Market Performance Analyses

Last year's Performance Review summarized a study of the New England ISO market by Bushnell and Saravia[11] that used a "competitive benchmark analysis." This competitive benchmark is the estimated price that would result if all firms acted as price-taking firms–that is, no firm exercises market power.[12] (The basis for examining wholesale market performance is discussed in Section I.) The study examined the period of May 1999 through September 2001. The results of the Lerner index estimation are summarized in Figure III.3. The Lerner index estimation uses their benchmark estimation with ISO New England's Energy Clearing Prices.

Bushnell and Saravia also graphed the relationship between demand and the Lerner index for May to September for 1999, 2000, and 2001, which is shown in Figure III.4. The graph is relatively flat for moderate levels of demand, indicating that the Lerner index (and market power markup) is low. However, at higher levels of demand, the index rises quickly and reaches values and reaches 20 percent just before 12,000 MW (for the 2001 estimate).[13]

The authors pronounce the overall results "encouraging," but caution:

> The results described above occur in a market with many layers of continued regulation. The vertical integration of some suppliers and the transition contracts imposed on others provide a powerful mitigating influence on the incentives of these firms to exercise market power. Any new contracts that replace those imposed during the transition will be set at terms determined by market conditions, rather than regulatory

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[11] James Bushnell and Celeste Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," Center for the Study of Energy Markets (CSEM WP-101), University of California Energy Institute, Berkeley, California, May 2002.

[12] This is based on an estimated incremental cost of the cheapest unit that is not needed to serve demand in a given hour.

[13] A similar graph that compares California, New England, and PJM Lerner Indices is in Section II of the 2003 Performance Review.

proceedings. The pending expiration of transition periods and potential consolidation of supply portfolios will reverse this effect.[14]

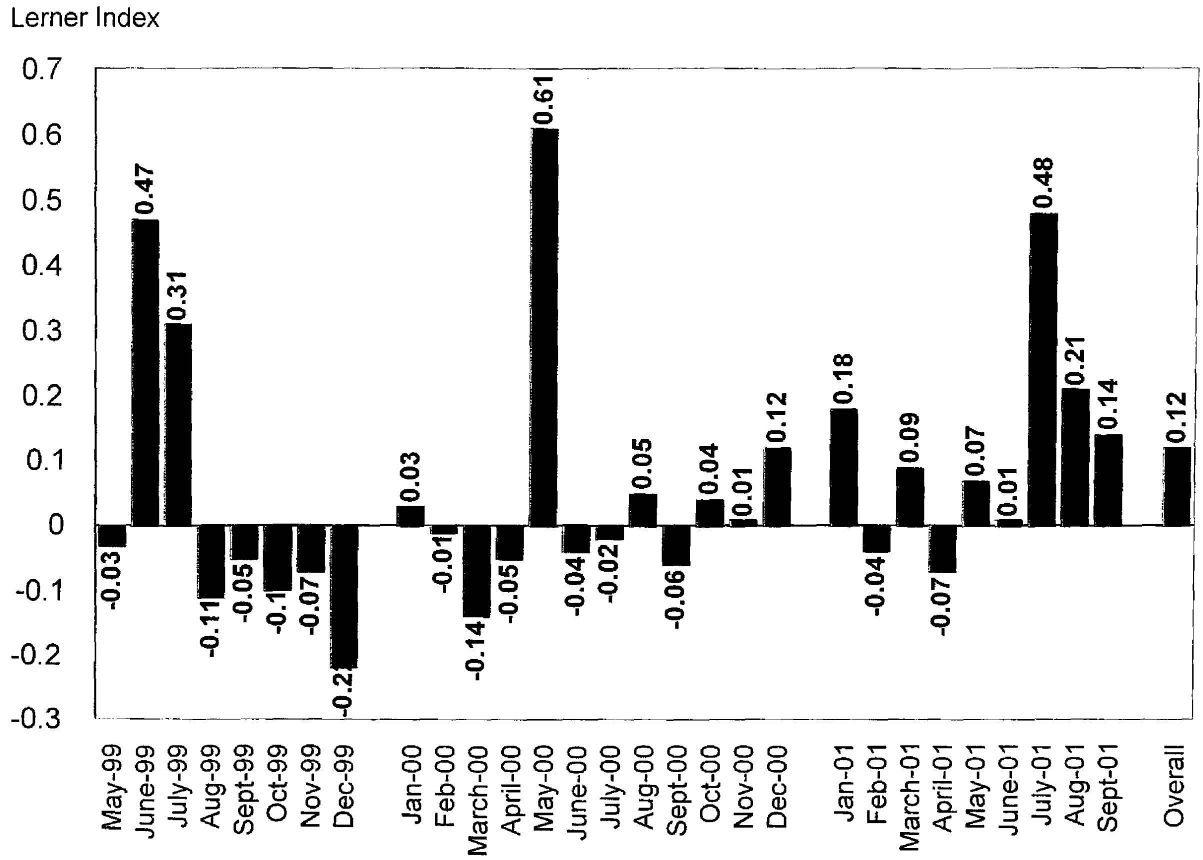

Figure III.3. Monthly Lerner Index for New England electricity market, May 1999 to September 2001.
Source: Bushnell and Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," May 2002.

[14]Bushnell and Saravia, p. 21.

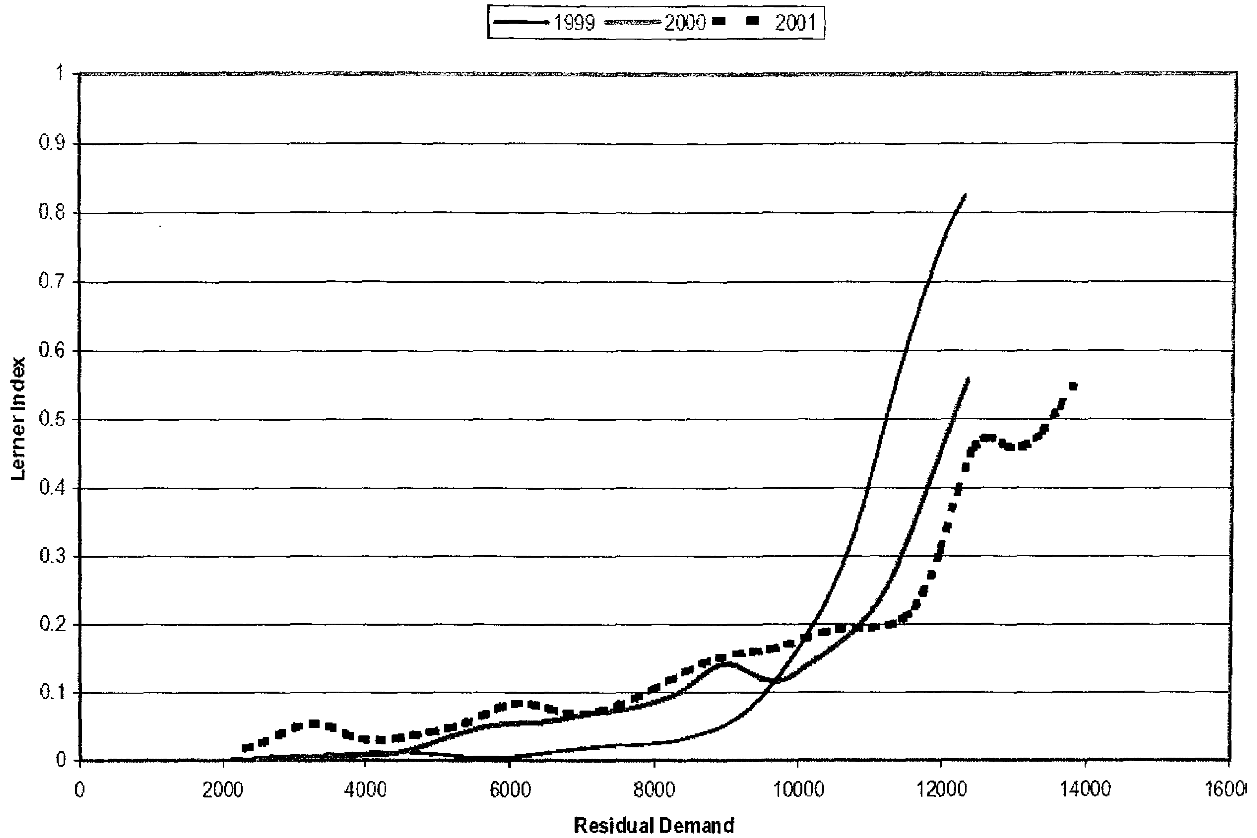

Figure III.4. The relationship between the level of demand and the Lerner index for New England.
Source: Bushnell and Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," May 2002.

ISO New England conducted its own annual assessment of the performance of the region's wholesale electricity markets.[15] The ISO's Market Monitoring Department also developed its own competitive benchmark analysis based on, with some

[15]ISO New England, 2003 Annual Markets Report, 2004. A 2002 analysis by the Independent Market Advisor to ISO New England, David B. Patton, Robert A. Sinclair, and Pallas M. LeeVanSchaick, "Competitive Assessment of the Energy Market in New England," Independent Market Advisor to ISO New England, Potomac Economics, Ltd., May 2002, was summarized in last year's Performance Review.

modifications, Bushnell and Saravia methodology. Their benchmark is similarly an estimate of the market price if market participants operated in a perfectly competitive market. The estimated benchmark price is based on production costs, unit availability, and net imports. This benchmark and the market prices are again used to calculate a Lerner index. Their quantity-weighted Lerner index is 11 percent for 2002 and nine percent for 2003. The ISO concludes that this indicates "that the New England markets continue to be workably competitive."

While the ISO's estimates are just below Bushnell and Saravia overall estimate of 12 percent, as Figure III.3 shows, there is considerable monthly variation in the Lerner index. And Figure III.4 shows that there is considerable variation as load increases. The ISO's report does not report any monthly or load-level estimates. While the estimation methodology may be similar, the reporting of the results were not.

The ISO's annual Lerner index estimates alone do not justify the firm conclusion they reach about the wholesale market's competitiveness. They do conduct other tests that characterize the market's structure. They use the Herfindahl-Hirschman Index (HHI, which is calculated as the sum of the squared market shares) to measure market concentration. Based on the Department of Justice's *Horizontal Merger Guidelines*, which is often used to interpret HHI results, a market is considered "highly concentrated" when the HHI is greater than 1800, "unconcentrated" below 1000, and "moderately concentrated" in the "gray area" between 1000 to 1800. HHI is usually used as a screening tools to decide if further investigation is necessary–not for a definitive answer on competitiveness or market power.

Overall, for the entire New England market, the ISO's HHI calculation shows a considerable drop in the index from over 1500 in 1999 to about 600 in late 2003. When broken down by sub-region, the ISO's 2003 HHI numbers show that five sub-regions have HHIs greater than 2000, two are just at or over 3000, and one, the Boston area, is greater than 5000.

The ISO also looks at market share, and note that the largest generator reduced its portfolio by 1,100 MW during 2003. They do not report the actual percentage shares of the generation in the region. One generator has nearly 4,000 MWs in December

2003, which appears to be approximately 19 percent to 20 percent of the generation of the ten largest generators (estimated from figure in the ISO's report).

The ISO also plotted outages and demand levels and note that as demand levels increase, there were fewer plant outages. They believe this suggests that markets are providing an incentive to make units available when most needed and that outages are scheduled by the ISO appropriately. They do not draw any conclusion on possible withholding or strategic behavior by suppliers from the observed negative correlation (as was done in the New York analysis discussed in section IV).

They also conduct a residual supply index (also called a pivotal supplier index) that measures the percentage of load that can be met without the largest supplier.[16] If the index is less than 100 percent, at least a portion of the largest supplier's capacity is needed to meet total demand and that supplier is "pivotal." The ISO's results show that the index was less that 100 percent only for 18 hours in 2003–all these hours occurred in June and July–and below 110 percent for only 161 hours–mostly in April, June, July and August (months it was above 20 hours). The 161 hours is less than two percent of the hours in a year. This index provides some indication of a supplier's ability to control the market price when there is a "pivotal" supplier. For this reason, this measure is a useful screening device for further analysis. However, it will not indicate whether a supplier actually exercised their market power and raised prices or the extent to which they actually raised prices. This test also cannot indicate the extent that strategies used by non-pivotal suppliers may be effective in influencing the market price.

Finally, the ISO makes a comparison of what a new generating unit's revenue requirement needs to be to cover costs of the unit and a competitive return on the investment with the revenues obtained from the energy, capacity, and ancillary services markets. Sufficient market revenues should indicate that new entry is profitable, while insufficient revenues would indicate that entry is being discouraged and could lead to higher prices in the future. The ISO's estimation for hypothetical generators in New England in 2003 indicates that the plants would not be able to recover annual fixed

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[16]That is, (total supply capacity − largest supplier capacity) ÷ total demand.

costs plus a return on investment from energy market revenues alone. They conclude that

> it appears that at 2003 electric energy prices and fuel costs, the hypothetical generators' net revenues were lower than the amount needed to cover a new entrant's fixed costs and competitive rate of return on investment. This observation is consistent with relatively robust reserve margins, the lack of announcements of new projects, few units in the early stages of construction, and the cancellation of some new generation projects.[17]

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[17] ISO New England, 2003 Annual Markets Report, p. 60.

Retail Markets

Five of the six New England states have retail access, Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island, and were among the first states to pass restructuring legislation and implement retail access. Maine and Massachusetts are updated below.

Maine

Maine's Restructuring Act required complete divestiture of transmission and distribution (T&D) utilities' generation assets. Maine chose to have the T&D utilities supply standard offer generation service to retail customers through a competitive process conducted by the Maine Public Utilities Commission. This has been done through a competitive bidding process or, if bids are insufficient or unacceptable to the Commission, through wholesale contracts. The T&D utilities themselves cannot participate in the bidding to become the standard offer provider and affiliates of the T&D utilities cannot provide more than 20 percent of the standard offer service in the affiliated T&D utility's service territory. Maine has one type of default service, the standard offer service, for each of the three primary retail customer classes.[18] This standard offer serves all customers in the class that are not receiving power from a competitively-obtained supplier.

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[18]The primary customer classes in Maine are Residential and Small Commercial (demand less than 20kW, 25kW, and 50kW, for Central Maine Power (CMP), Bangor Hydro-Electric (BHE), and Maine Public Service (MPS), respectively), Commercial (greater than 20kW, 25kW, or 50kW for CMP, BHE, and MPS, respectively, but less than 400kW for CMP and less than 500kW for BHE and MPS), and Industrial (demand greater than 400kW for CMP and greater than 500kW for BHE and MPS). Maine also uses the corresponding categories, as in Table III.1, Residential and Small Non-Residential, Medium Non-Residential, and Large Non-Residential.

The Commission has, at this time, completed a fourth year of competitive bids.[19] Table III.1 summarizes the results of each of the four rounds of bids. The Commission refers to the first two bidding experiences as meeting with "mixed results." The last two years, however, have been much more successful for securing standard offer supply. In early 2004, the Commission reports that 63 percent of the state's electric load were on standard offer service. About 66 percent of the medium commercial and industrial customers, 17 percent of the large commercial and industrial customers, and nearly all residential and small commercial customers are on standard offer service.[20]

While the bidding process for Bangor Hydro-Electric (BHE) was unsuccessful the first two years at finding acceptable bids for all customer categories, Central Maine Power (CMP) was only successful for residential and small non-residential customers. By the third year, all customer categories for both companies were served by acceptable standard offer prices found through the competitive bidding process. The standard offer price has increased for residential and small commercial customers since 2000, increasing 22 percent in BHE's area and by 21 percent for customers in CMP's area. The rates for these customers have been in effect since March 1, 2002 and will remain in effect through February 28, 2005. There has been no switching to competitive providers by residential and small commercial customers in either BHE's or CMP's areas (see Figures III.5 and III.6 below), consequently, all of these customers are on standard offer service. (There have been no direct offers to residential customers in the service areas of BHE and CMP since July 2001.) Currently all standard offer service prices for all customers classes for the three principle T&D utilities in the state have been procured through the competitive bidding process. The larger customer groups have been more active for these service areas, with considerable fluctuation in the large non-residential customer load in BHE's service

[19]This information is from the Maine Public Utilities Commission's various postings on their website.

[20]State of Maine Public Utilities Commission, 2003 Annual Report, February 1, 2004.

territory. Large customer load in CMP's area has climbed to nearly 90 percent for June 2004.

For Maine Public Service (MPS), the bidding process has been able to obtain successful bidders despite the fact that MPS is in northern Maine and not part of the ISO New England control area. The Commission notes that while there has been some competition in this area, "there has been a limited number of suppliers active in the market."[21] The Commission noted in 2004 that a competitive supplier in northern Maine in 2003 stopped offering service to new customers, and customers began to return to standard offer service.[22] This supplier is one of the only two active suppliers serving northern Maine since retail access began in the state. The MPS standard offer price for residential and small commercial customers had increased by 35 percent between early 2001 and the price that went into effect in March of 2003. The standard offer rate in effect from March 1, 2004 through December 31, 2006, is about six percent lower than the previous year's rate. Commercial and industrial standard offer prices had increased 37 percent and 56 percent, respectively from 2001 to 2003. The 2004 through 2006 rates for commercial customers dropped slightly, about a half a percent, and industrial customers' rate increased by just over two percent.

MPS load served by competitive providers has fluctuated since the beginning of retail access (Figure III.7). About 60 percent of the total load was served by competitive suppliers in mid-2003, but that has since dropped to 47 percent of the load. Residential load has dropped to 13 percent of customer load, after peaking at 36 percent in July 2003. Medium and large non-residential customers, however, remain at 63 percent and 93 percent, respectively. Large customer load has been between 93 percent and 100 percent of the load since early 2002. In 2002, the total number of customers served by MPS was reported at 35,467 residential, 193 medium, and sixteen large customers.

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[21]Maine Public Utilities Commission, "Standard Offer Study and Recommendations Regarding Service After March 1, 2005," December 1, 2002, p. 8.

[22]State of Maine Public Utilities Commission, "2003 Annual Report," February 1, 2004.

Table III.1. Summary of Maine's standard offer bidding process.

	Year 1: for service beginning March 2000	Year 2: for service beginning March 2001	Year 3: for service beginning March 2002	Year 4: service beginning March 2003
Bangor Hydro-Electric Co. (BHE) Residential & Small Non-Residential	All bids rejected – BHE directed by Commission to procure power in wholesale market for all 3 classes	All bids rejected – BHE directed by Commission to procure power in wholesale market for all 3 classes	3 year contract accepted for residential and small non-residential customers	Contract continues from March 2002 to February 2005
Medium Non-Residential			1 year contract accepted for medium and large non-resid. customers	6 month contract March 1, 2004 through August 31, 2004
Large Non-Residential				
Central Maine Power Co. (CMP) Residential & Small Non-Residential	2 year contract accepted for residential and small non-residential	no bid – contract continues for this class	3 year contract accepted for residential and small non-residential customers	Contract continues from March 2002 to February 2005
Medium Non-Residential	Bids rejected – CMP directed by Commission to procure power in wholesale market for medium and large non-residential customers	Bids rejected – CMP directed by Commission to procure power in wholesale market for medium and large non-residential customers	1 year contract accepted for medium and large non-residential customers	6 month contract March 1, 2004 through August 31, 2004
Large Non-Residential				
Maine Public Service Co. (MPS) Residential & Small Non-Residential	1 bidder chosen	three year term contract for all 3 standard offer rate classes (until 2/28/04)	no bid – contract continues for all classes	Contract March 1, 2004 through December 31, 2006
Medium Non-Residential	service split 80/20 between 2 bidders			
Large Non-Residential	1 bidder chosen			

Source: From information in "Detailed Summary of Standard Offer Bid Processes and Results," Maine Public Utilities Commission.

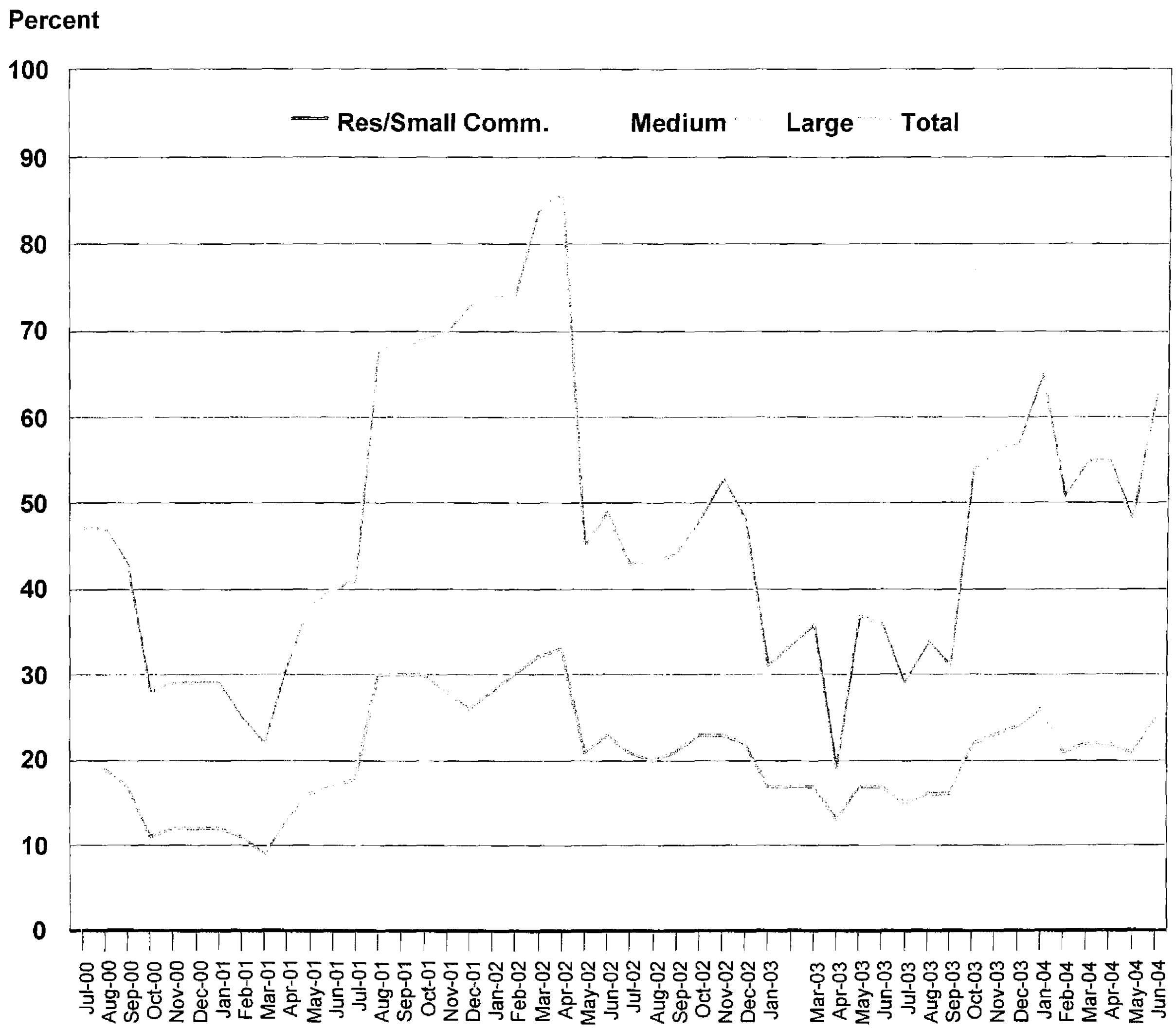

Figure III.5. Percentage of load served by competitive providers in Bangor Hydro-Electric Co.'s (BHE) service territory. (Note: No data was reported for February 2003.) Source: Maine Public Utilities Commission, June 2004.

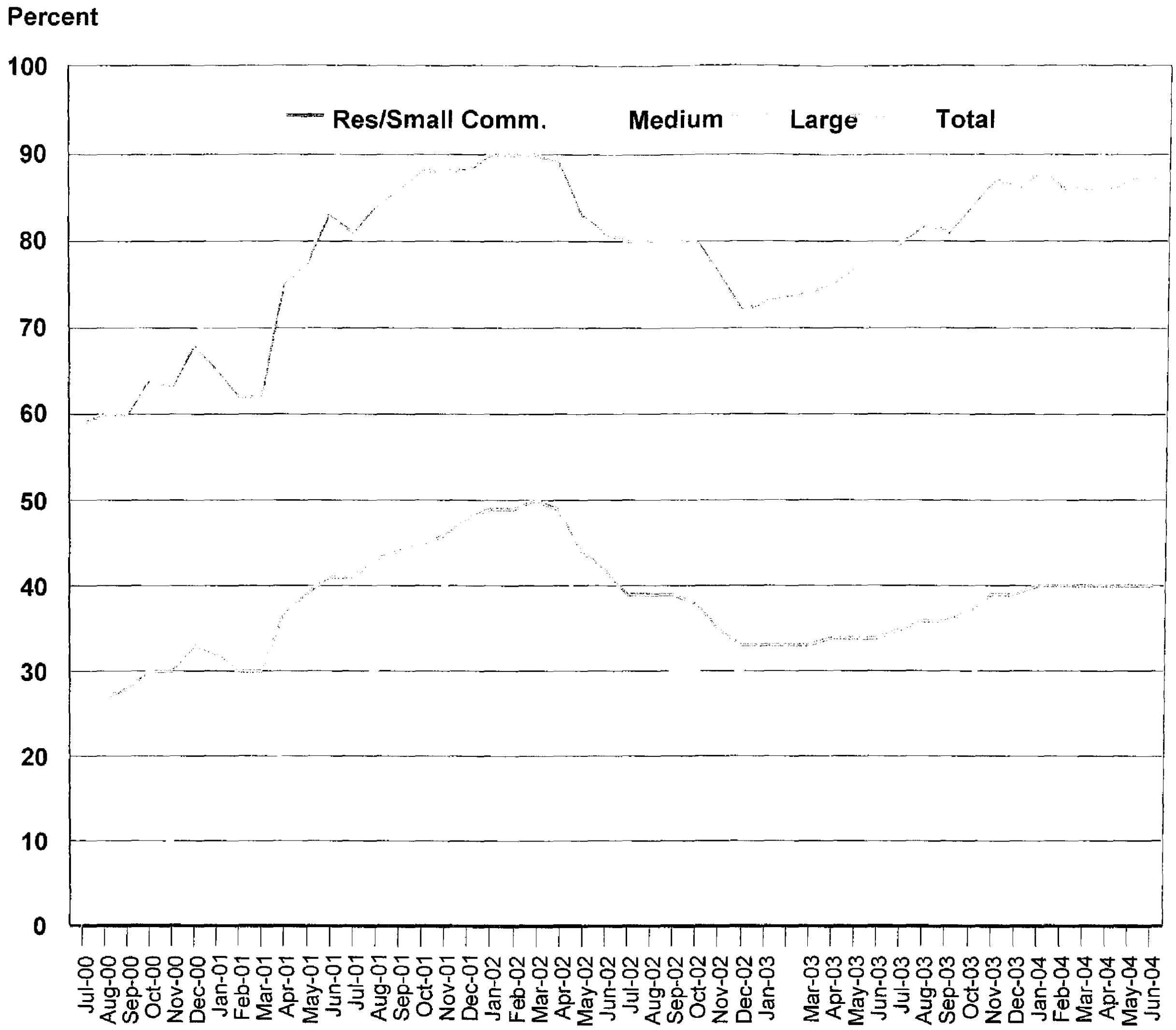

Figure III.6. Percentage of load served by competitive providers in Central Maine Power Co.'s (CMP) service territory. (Note: No data was reported for February 2003.) Source: Maine Public Utilities Commission, June 2004.

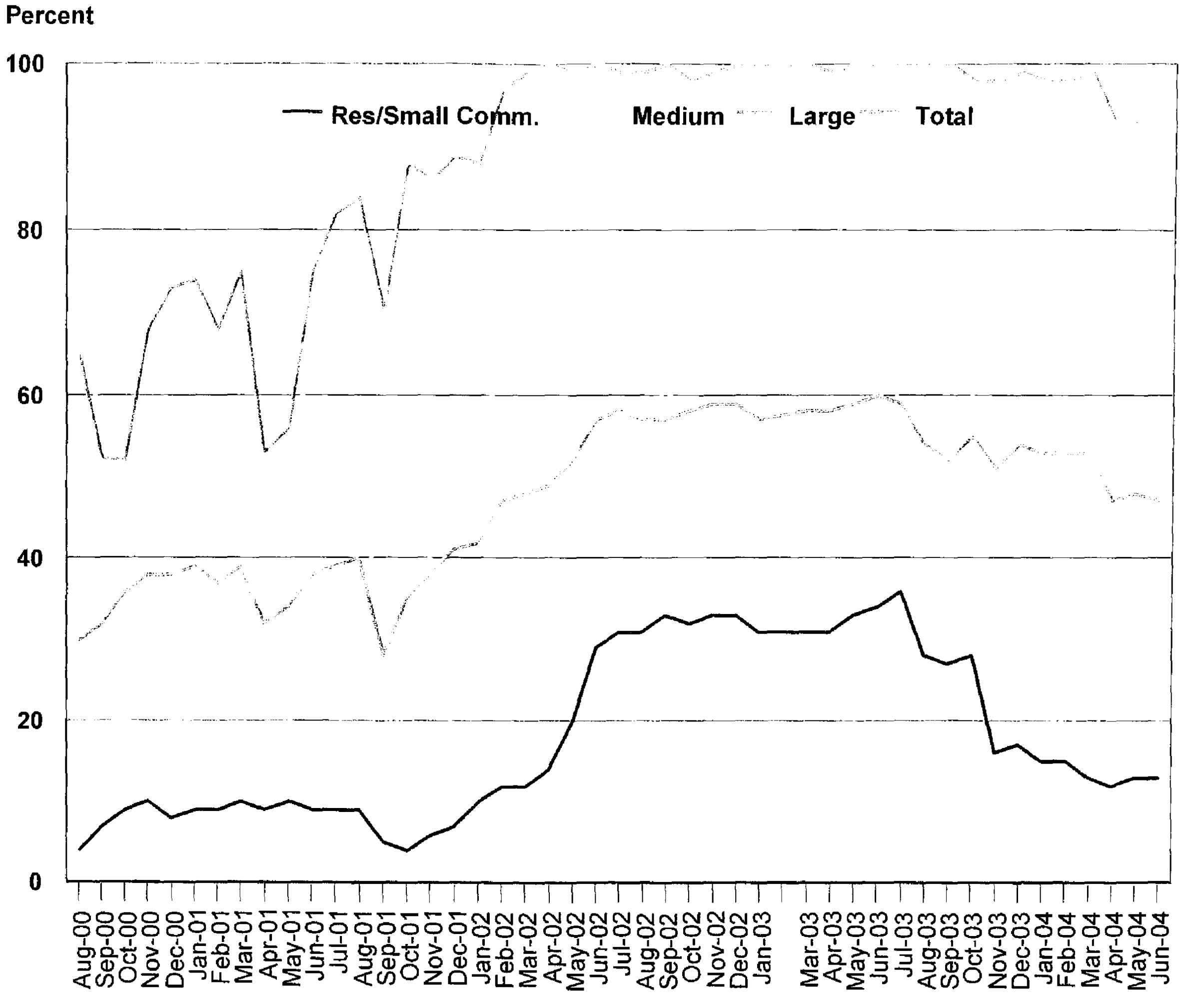

Figure III.7. Percentage of load served by competitive providers in Maine Public Service Co.'s (MPS) service territory. (Note: No data was reported for February 2003.) Source: Maine Public Utilities Commission, June 2004.

Massachusetts

The Massachusetts Electricity Restructuring Law, passed in 1998, provides three electric generation service options to consumers: (1) standard offer service provided by distribution companies, a transition generation service available to each distribution company's customers through February 2005, and assigned to customers who had not selected a competitive supplier as of March 1, 1998; (2) default service provided by distribution companies, customers who move into a distribution company's service territory after March 1, 1998, are not eligible to receive standard-offer service and are placed on default service until they select a competitive supplier (which is higher cost that the standard offer); and (3) competitive generation service provided by competitive suppliers.

While there has been an increase in residential customer activity since 2002, statewide, it is still less than three percent of the customers that have switched to a competitive supplier. Figure III.8 shows the trends since April 1999 of the percent of customers choosing a competitive supplier by customer categories. The larger customer categories continue to show considerably more activity. There was a marked decrease from the fall of 2002 to mid-2003 for the large commercial and industrial customer group, which had fallen below 20 percent, but then increased to above 30 percent by late 2003. Small and medium commercial and industrial customer groups both remain at less than 12 percent of customers for each category. The pattern is similar in terms of kilowatt-hours, but at higher percentages, as shown in Figure III.9 below.

Figure III.10 and Figure III.11 are a cross section of customer switching activity for May 2004 to show where the activity is in terms of customer groups and kWhs for each of the distribution companies. Commonwealth Electric had the most activity across every customer group. This included residential customers, at 15 percent served by competitive suppliers, which was by far the highest in the state for any area. For the larger customer groups, Fitchburg and Massachusetts Electric large commercial and industrial customers were both over 40 percent. Five of the seven company territories had over 25 percent of the large commercial and industrial customers being served by competitive suppliers. In terms of kWhs, all companies (except Nantucket) had large commercial and industrial customer load above 20 percent served by alternative suppliers. Fitchburg was over 80 percent of the large commercial and industrial load being served by competitive suppliers.

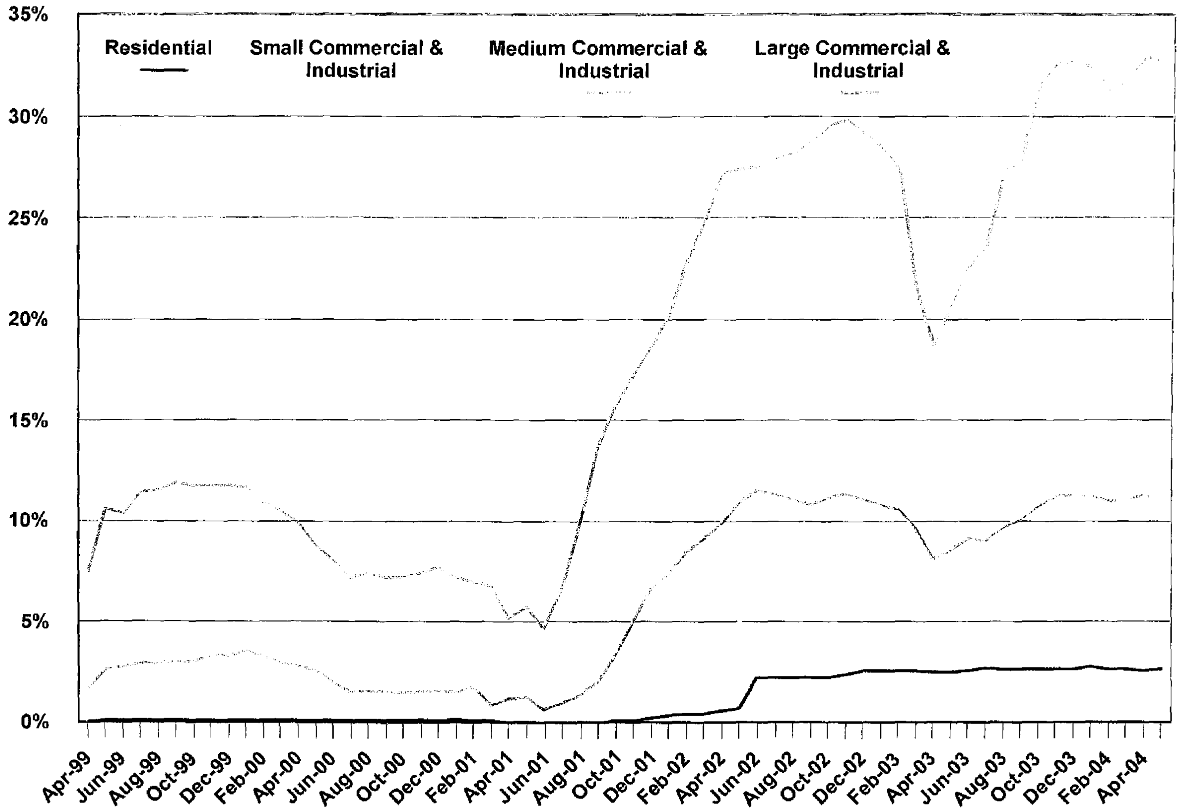

Figure III.8. Massachusetts percent of customers served by competitive generation, April 1999 to May 2004.*
Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," April 1999 through May 2004 reports.
*The percentage calculated for Large Commercial & Industrial customers for July 2002 was omitted because it appeared to be incorrectly recorded.

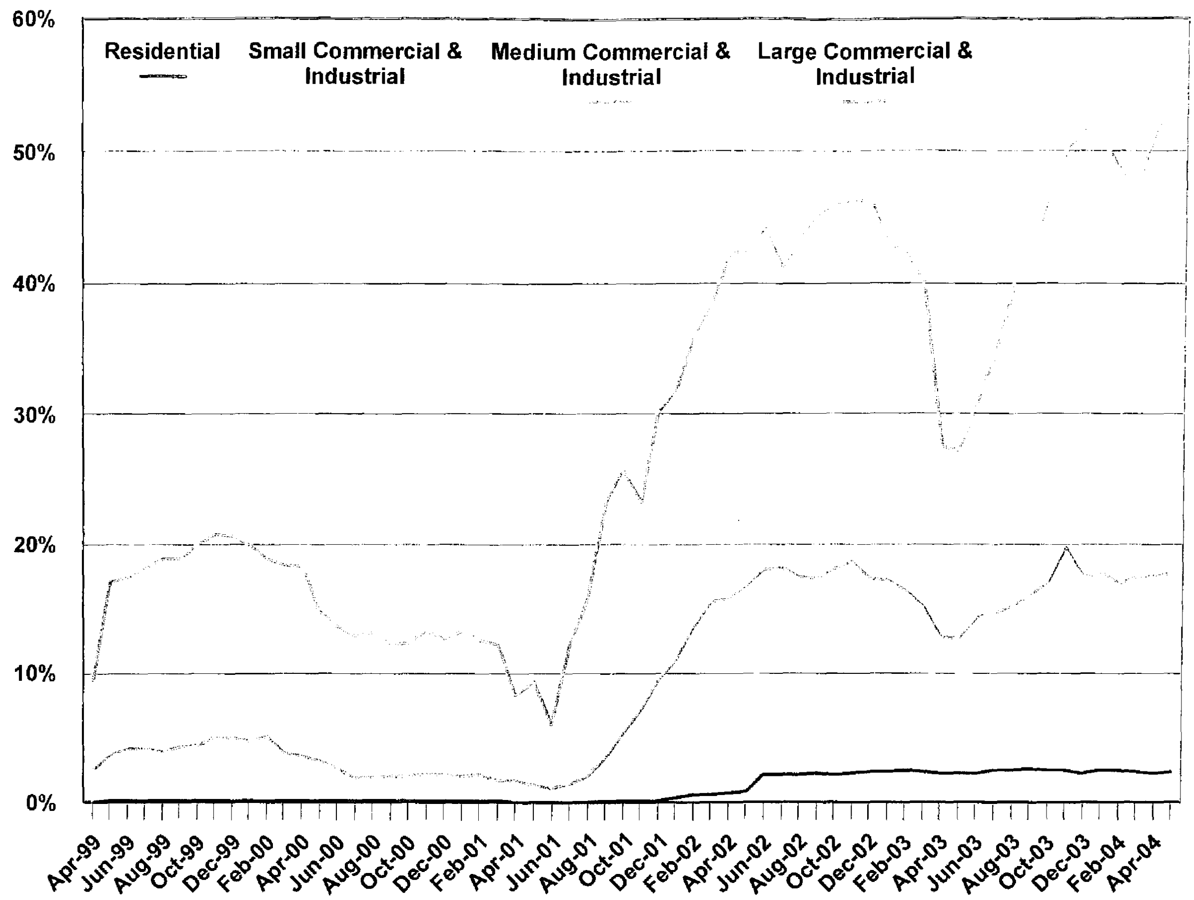

Figure III.9. Massachusetts percent of load (kWh) provided by competitive generation, April 1999 to May 2004.
Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," April 1999 through May 2004 reports.

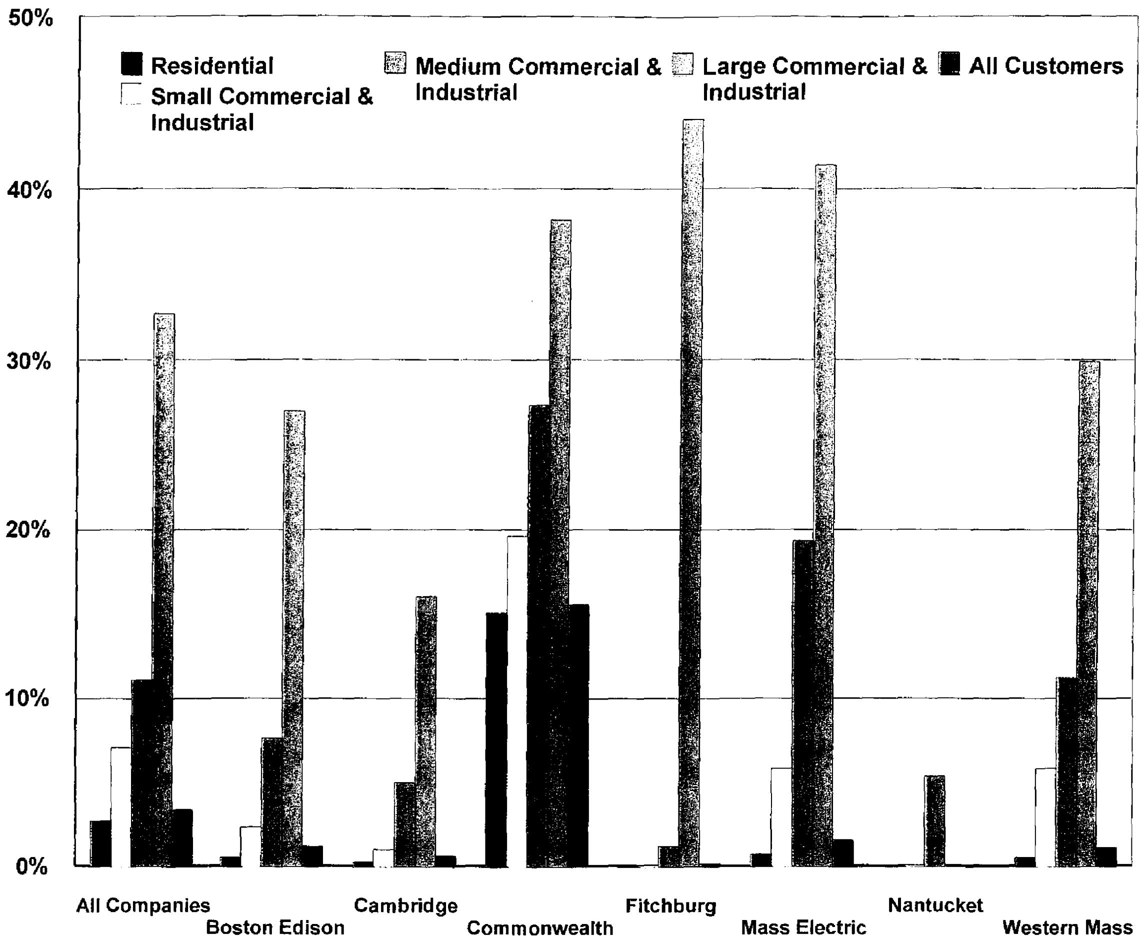

Figure III.10. Massachusetts company comparison by percent of customers served by competitive suppliers, May 2004.
Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," May 2004 report.

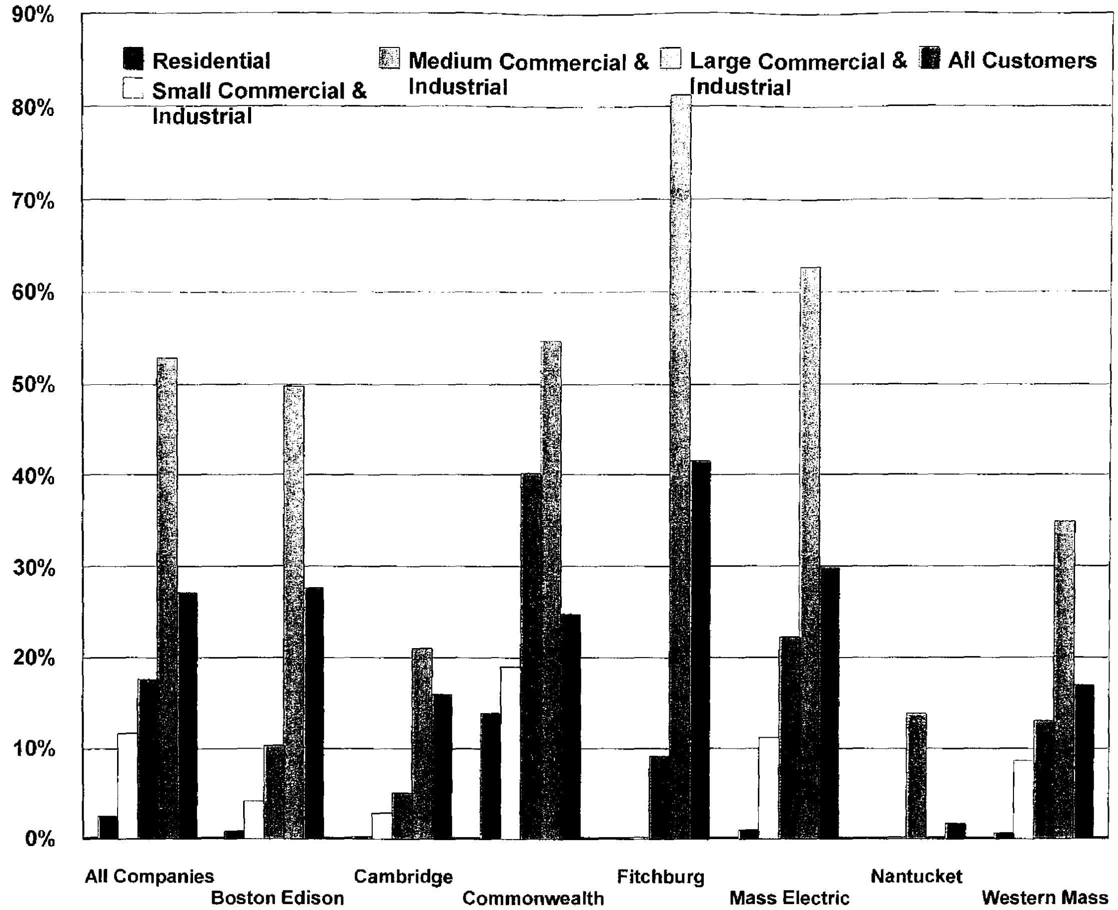

Figure III.11. Massachusetts company comparison by percent of load (kWhs) served by competitive suppliers, May 2004.
Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," May 2004 report.

Section IV
New York

Wholesale Market

The New York Independent System Operator (NYISO) operates the state's major transmission system and administers the wholesale markets for electricity in New York. The NYISO is a not-for-profit organization formed in 1998, is operated from a Power Control Center near Albany, New York and is governed by an independent, ten-member board. The NYISO developed directly from the New York Power Pool that was created by the state's eight largest electric utilities following the 1965 northeast blackout. The Power Pool coordinated the state's interconnected transmission system, designed and operated the control center, and developed the power pool's economic dispatch program. The NYISO began operations on December 1, 1999, after receiving FERC approval and assumed full operation of New York's wholesale electric system from the New York Power Pool. The New York summer 2004 total installed generating capacity is expected to be almost 38,000 MW.

The markets the NYISO currently operates are a day ahead market (where capacity, energy, and ancillary services are scheduled and sold for the following day), a real time market (where capacity, energy, and ancillary services are sold for one-hour periods), and ancillary services markets (which includes spinning reserve, 10-minute non-synchronized reserves and 30-minute reserves, and black start capability). In addition there are Transmission Congestion Contracts (TCC) and an Installed Capacity market (ICAP).

The NYISO has been concerned in recent years about the state's need for additional generation resources, particularly for New York City and Long Island. Of the 5,000 to 7,000 additional megawatts (MW) of generation originally recommended by the NYISO to be in place by 2008, more than 3,000 MW has been built and an additional 2,038 MW are under construction. There are also 3,120 MW approved by the siting process, but are not assured of completion.[1] However, the NYISO projects that New York City and Long Island will not be able to meet their capacity requirements after 2008 unless new generation, that is not already under construction, is built or scheduled retirements are deferred. They are recommending that an additional 2,000 MW of new generation be added by 2009, mostly in New York City and on Long Island, and that 500 to 1,000 MW be constructed annually thereafter, depending on electricity demand growth.

Also according to the NYISO, only one new transmission line has been constructed in New York in more than a decade. This is a direct current cable that runs across Long Island Sound from Connecticut to Long Island. This "Cross Sound Cable" was built by a merchant enterprise and is in operation, but has faced legal challenges. Its continued operation will depend on the outcome of the litigation and possible congressional action.

Figure IV.1 shows the load weighted monthly average prices for the Day Ahead Market of the New York ISO from May 2001 to April 2004. As with other power markets around the country, the impact from the higher natural gas prices in early 2003 and January 2004 can be seen, when prices reached $75 per MWh in February and March of 2003 and again in January 2004. Prices retreated to below $50 per MWh in May of 2003 and reached a summer peak of over $67 in August of 2003. It is worth noting that the highest prices for 2003 and 2004, and for the three year period, were reached in the winter months, not the summer as seen in 2001 and 2002. This reflects the particularly volatile natural gas markets at those times and the increased impact that natural gas prices now have on power prices (as discussed in Section I).

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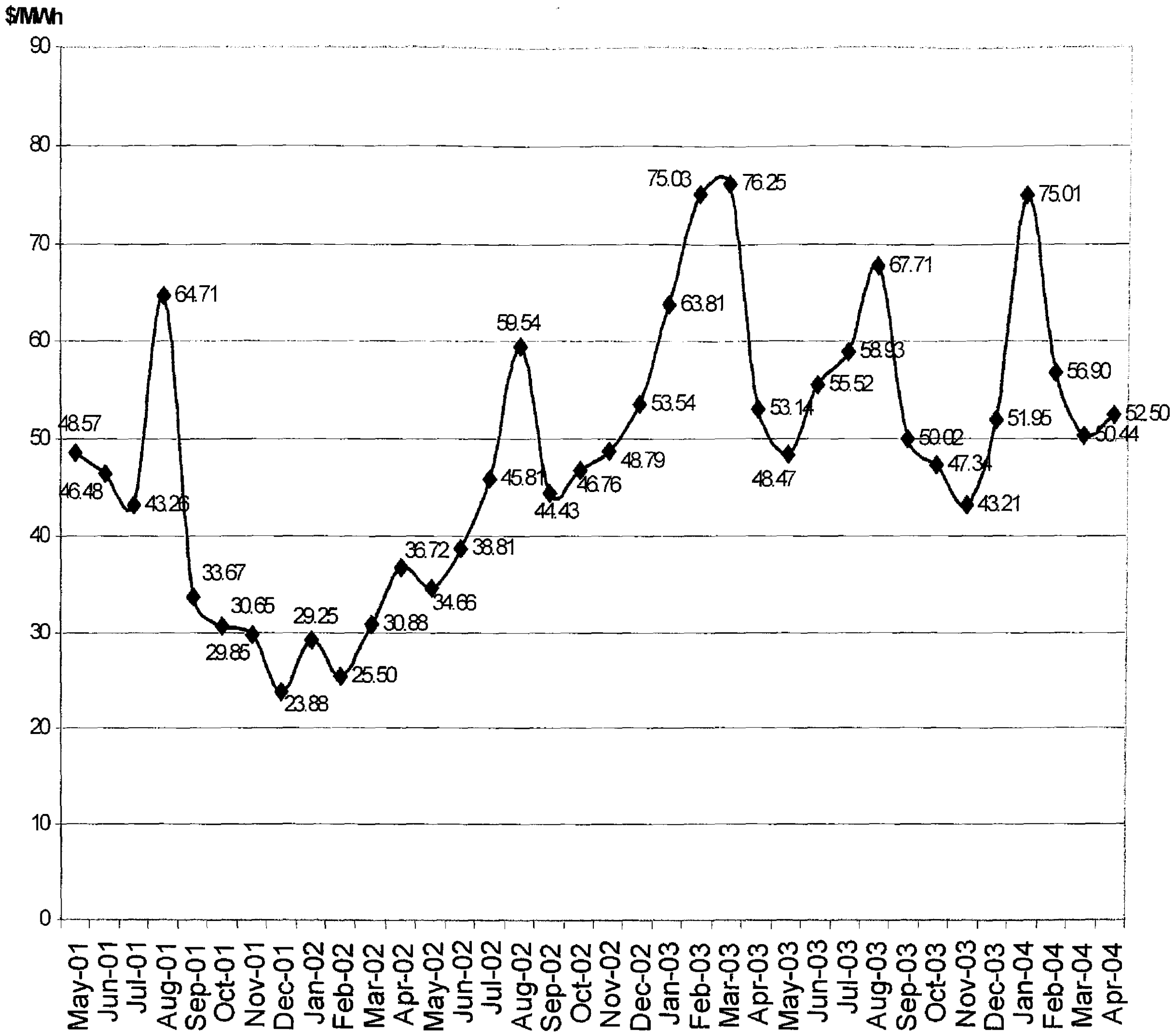
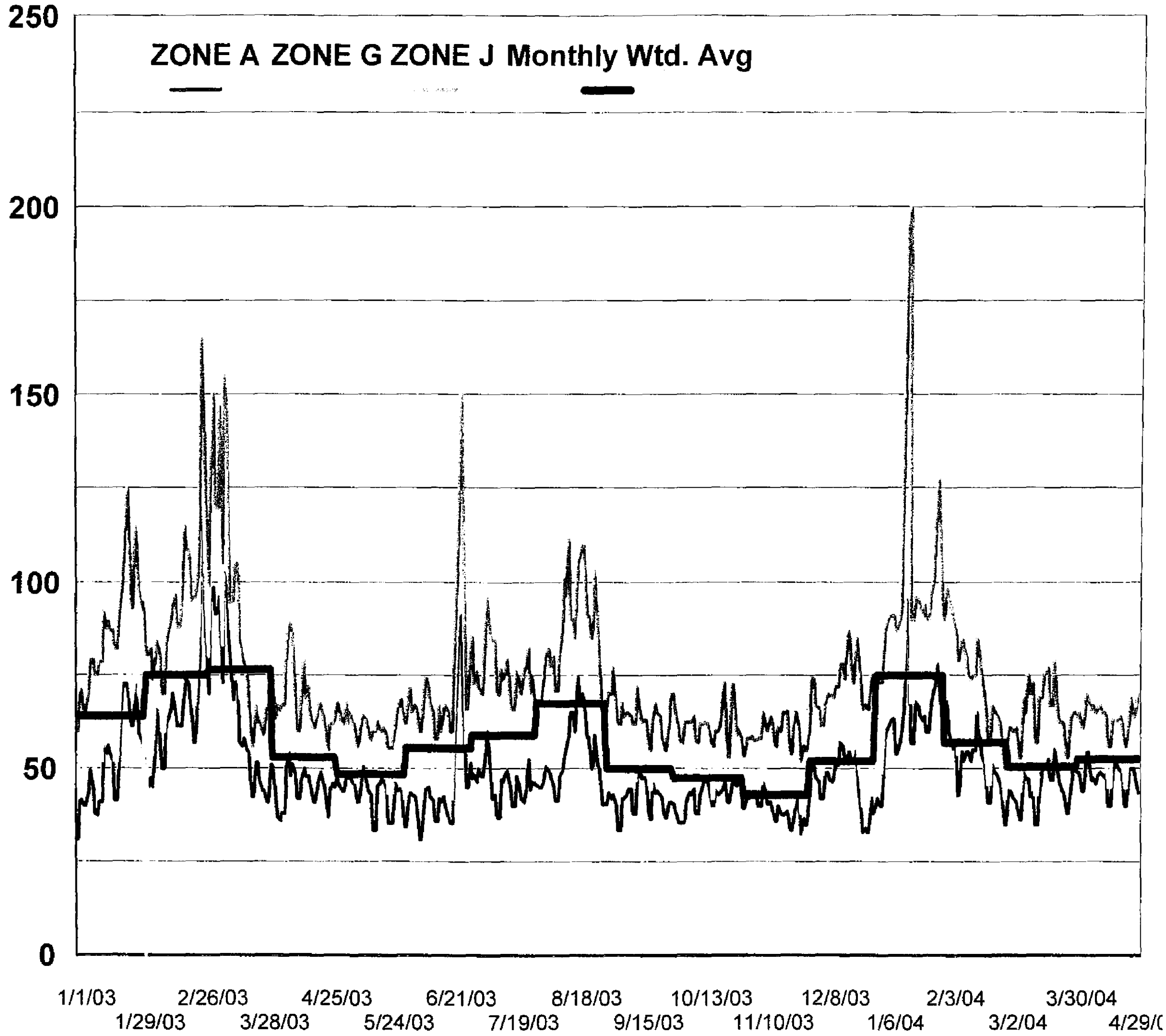
[1] *ISO Power Trends, New York's Success & Unfinished Business*, Report by the New York Independent System Operator, May 2004.



Data Source: New York ISO, May 2001 through April 2004.

Figure IV.1. New York ISO load weighted monthly average day ahead market prices.

Figure IV.2 graphs the daily variation in three New York ISO zones and the weighted monthly prices for January 2003 through April 2004. Zone A is the western most zone in the state, Zone G is the Hudson Valley region in the south eastern part of the state, and Zone J is New York City (there are a total of 11 zones in the state). The daily zone prices tend to fluctuate together, but the relatively resource constrained Zone J prices are consistently higher than the other two zones. While there were price spikes during the summer of 2003, the highest daily peaks were again during the winter months in early 2003 and 2004–spiking to $200 per MWh in January 2004. Power prices remained volatile into early spring as well in both years.



Data Sources: Platts Megawatt Daily and New York ISO, January 2003 through April 2004.

Figure IV.2. New York ISO Daily and Monthly Weighted-Average Prices.

Wholesale Market Performance

The Independent Market Advisor (IMA), the NYISO's independent market monitor, issued a "State of the Market" report in May 2004[2] that included some market performance analysis. In an attempt to determine if there was physical withholding of capacity that could be an indication that suppliers were attempting to raise prices by exercising market power (as explained in Section 1), the IMA analyzed generator deratings. Deratings occur when a supplier reduces the output either completely or partially from a power plant. The IMA considered only non-planned outages in their analysis, assuming that "planned outages are legitimate and are not aimed at exercising market power" (p. 24). They also considered only hours of higher demand, on the assumption that withholding of generation resources would increase as demand increases. They only examine areas east of the Central-East interface, assuming that transmission and generation constraints in eastern New York would likely increase the opportunity to exercise market power. Based on this analysis, they concluded "that no (statistically) significant relationship existed between deratings and load level in 2003, which would lead us to reject the hypothesis that market power was systematically exercised through physical withholding" (p. 25).

This analysis is too restrictive to draw a conclusion that there was no exercise of market power in New York's wholesale market, only that they believed that market power was not being exercised through physical withholding based on their analysis. However, their analysis may be too limited to detect even this behavior since it is likely based on a faulty assumption–that is, if suppliers had market power and were withholding capacity, withholding would increase as demand increased. At high levels of demand, the supply curve becomes very or nearly vertical. During these hours, even withholding a small amount of capacity would have a considerable impact of the market clearing price for power. This would make it unlikely that there would be a direct correlation between withholding (deratings) and demand level even though some suppliers may in fact be exercising market power. Their analysis, in other words, may

[2] *2003 State of the Market Report, New York ISO*, Potomac Economics, Ltd., Independent Market Advisor to the New York ISO, May 2004.

falsely reject the hypothesis of there being market power simply because there is no correlation between withholding of capacity and demand when market power is exercised.

Also, it is not certain the assumption that planned outages are always "legitimate" and are not intended to influence prices is a correct one either. While it is impossible to predict exactly when there will be the hottest days during the summer months, it is highly probable that those months will be warm and that most generating capacity will be needed. No mention is made if any analysis was conducted to determine if there has been any shifting of planned outages over the years from shoulder periods (spring and fall) to peak periods (summer and winter) or if there was a shift in when unplanned outages occurred.[3]

Finally, while it is reasonable to conclude that the constraints into eastern New York would make it relatively easier to exercise market power, there was no mention if any similar analysis was conduct for other areas of the state. There was also no discussion on whether the extensive price mitigation that occurred for the New York City load pocket during 2003 may have had any impact on their findings.

The IMA also conducted an "output gap" analysis to determine if there was economic withholding of capacity. They define "output gap" as "the quantity of generation capacity that is economic at the market clearing price, but is not running due to the owner's offer price . . . [was] substantially above competitive levels" (p. 27). "Reference values" based on past offers during "competitive periods" are used to compare with supplier offer prices. The assumption is that suppliers will offer prices near their marginal cost during these "competitive periods," since offers above marginal cost will not be selected for dispatch. Offers are considered above competitive levels if it exceeds reference values by the "mitigation threshold" (the lower of $100/MWh or 300

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[3]While the evidence is circumstantial, FERC data indicates that in California there was a decrease in planned outages during the spring of 2000 when compared to the spring of 1999 and a increase during the early summer of 2000, when the western power crisis began. Unplanned outages increased considerably (over 400 percent increase) during the summer of 2000 when compared to 1999. This suggest both a shifting of planned outage to the higher demand season and possible deferral of maintenance that forces an unplanned outages and, of course, deliberate withholding during critical times.

percent) and a "low threshold" (the lower of \$50/MWh or 100 percent). Similar to their analysis of deratings, they assume that the "output gap" would increase as load increases, if suppliers are using economic withholding to exercise market power. Again the analysis is only done for eastern New York. The IMA found that there was "no correlation between load and the output gap" and concluded "that economic withholding was not a significant issue in New York in 2003" (p. 28).

Again, the analysis is too restrictive to draw a conclusion that there was no exercise of market power in New York's wholesale market, only that the IMA believed that market power was not being exercised through economic withholding. However, it is also not clear if there would be a correlation between "output gap" and demand. They measured the "output gap" in megawatts (MW), however, it may be more likely there is a correlation between the "gap" in terms of price (that is, the difference between the reference price and bid, in \$/MWh) and demand. This could indicate that suppliers were able to obtain a higher price from economic withholding as demand increased. They did not report if this analysis was attempted using a "price gap" rather than a "output gap."

Another limitation is the use of past offers as reference values. Their assumption that suppliers will bid close to their marginal cost presupposes that these are competitive periods of no or only limited market power. However, if this assumption is incorrect, and suppliers have some significant level of market power, then the reference price will be higher than marginal cost and not a suitable approximation. This would mean fewer MWs being identified as an "output gap," because the spread between the reference value and the actual bid would be lower and less likely to exceed the thresholds. Also, the thresholds criteria is relatively large and again would mean fewer MWs being identified as an "output gap." Both these limitations of the methodologies will lead to the incorrect conclusion that there is no significant economic withholding, when it could in fact be occurring.

By definition, supplier market power will impact prices, since it is the price leveraging ability (or power) to significantly raise prices above what would occur in a competitive market. Therefore, these approaches used by the IMA are, at best, an indirect approach aimed at detecting a secondary affect, the physical or economic withholding of capacity to increase prices. At worst, this could lead to the conclusion that market power does not exist or is at sufficiently low level to not warrant any concern, when it is in fact significant. More rigorous and careful analysis than these are needed to draw more definitive conclusions about New York wholesale market performance.

The IMA conducted an evaluation of the references prices in an attempt to see if their assumption that supplier offer prices are close to marginal costs (p. 37). The reference prices are also the basis for market mitigation in New York. To make this comparison, they compare average reference prices in the real-time market for fossil-fired units to estimated average variable production cost. They found that statewide, reference prices were three percent below average variable cost and with cogeneration units removed from the analysis, reference prices were 1.2 percent below average variable cost (p. 39). However, since the comparison is presented in a nonstandard manner (they use a per-megawatt average, rather than megawatt hours or other energy measure), it obscures the results and prevents a valid comparison of reference price and supplier costs. Other assumptions appear overly restrictive as well to provide useful results, such as, the comparison was made for only one day in each month of 2003.

Retail Market

New York is the only state where the electric industry restructuring was not initiated by the state legislature. The New York Public Service Commission determined that it could begin restructuring with its existing authority under state law. In May of 1996, the NYPSC issued its order (Opinion 96-12) that restructured New York's electric power industry and opened the state's electric industry to competition.[4] This order required utilities to file rate and restructuring plans. In late 1997 and early 1998, the

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[4]In response to the May 1996 PSC Order requiring utilities to file restructuring plans, New York utilities filed suit against the PSC, contending that the PSC did not have jurisdiction to implement retail access or require divestiture of their generation assets. The case went to the New York Supreme Court where the Court determined that the PSC, under New York law, has such jurisdiction – allowing restructuring to proceed.

Commission approved six restructuring orders for the following utilities: Consolidated Edison Company of New York, Inc. (Con Edison); Central Hudson Gas and Electric Corporation (Central Hudson); Orange and Rockland Utilities, Inc. (O&R); New York State Electric and Gas Corporation (NYSEG); Niagara Mohawk Power Corporation (Niagara Mohawk or NIMO); and Rochester Gas and Electric Corporation (RG&E).

A seventh utility, Long Island Lighting Company's (LILCO's) transferred its electric transmission and distribution system and nuclear assets to the Long Island Power Authority (LIPA) in 1997. LILCO's gas assets and operations and its non-nuclear generating assets and operations were transferred to subsidiaries and then purchased in 1998, by corporate entities associated with Brooklyn Union Gas Company.[5] The NYPSC does not have pricing or operational regulatory authority over the LIPA system.

All of the orders originally required either rate reductions or freezes for all classes of customers and all but one of the orders (for RG&E) required divestiture of all, or substantially all, of the utilities non-nuclear generating facilities. There was a transition period of three to five years that phased-in competition to when all customers where eligible to purchase their electricity from alternative suppliers. During this transition period, rates for electricity and delivery services were set by the Commission. Also from the settlements, companies face financial penalties if reliability or customer service deteriorates from past levels. The utility settlements reached with the NYPSC are summarized in Text Box IV.1.

Currently, all rate caps and freezes have expired and all customers' power supply prices are being determined by the market, either from the supplier they chose or based on the ISO price. The two main components of the customers' price for power are for (1) generation services or the supply charge, which is based on the market price

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[5]KeySpan Corporation was formed from the merger of KeySpan Energy Corporation, the parent company of Brooklyn Union Gas, and certain businesses of the Long Island Lighting Company. KeySpan now owns and operates generating plants on Long Island and New York City with total capacity of more than 6,400 megawatts and serves approximately 1.1 million electric customers through a management service agreement with the Long Island Power Authority (information from http://www.keyspanenergy.com/).

for power, and (2) delivery services, which is the regulated rate for transmission and distribution services and other charges.

Most rates in the state have a delivery charge that include an adjustment factor to mitigate market volatility. For example, NIMO's rates have a *supply charge* based on the NYISO market price and a *delivery charge* that includes charges for transmission and distribution, "Competitive Transition Charge" (for "stranded cost"), "System Benefit Charge," and a "Delivery Charge Adjustment" (DCA). The DCA reconciles the forecasted market price with the actual market price to allow the company to recover customer supply costs and provides some mitigation against market price volatility.[6]

Customers may receive a credit for switching to an alternative supplier or Energy Service Company (ESCO) that is intended to reflect costs the utility avoids when a customer switches to another supplier. For example, NIMO residential and small commercial and industrial customers received a credit of 4 mills per kWh and all other customers receive a credit of 2 mills per kWh when they choose to received their generation service from an ESCO.[7] An ESCO may be an independent electricity supplier, or an affiliate of the former local utility or another utility company. Con Edison had a retail access incentive for small customers who signed up in April 1998 to buy power from an ESCO, and received a credit on their bill of $50 for residential customers and $75 for small business customers. These customers had to agree to stay with the ESCO for at least ten months. ESCOs were allowed discretion in using the incentive payment, including using some of the funds to cover marketing costs. Most customers who took the offer received a rebate.

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[6]Kajal Kapur, "New York Deregulation Model: Characteristics and Success," Energy Pulse, www.energypulse.net.

[7]Kapur, "New York Deregulation Model: Characteristics and Success."

Text Box IV.1. The following are highlights of the utility settlements reached with the NYPSC:*

Con Edison

- 25 percent immediate rate decrease for large industrial customers, fixed for five years.
- 10 percent rate decrease for all other customers, phased in over five years.
- Con Edison rates for electricity and delivery will be set by the PSC during the transition.
- Con Edison customers who signed up in April 1998 to buy power from an ESCO got credit on their bill of $50 for residential customers and $75 for small business customers. Customers had to agree to stay with the ESCO for at least ten months.
- Retail Choice Phase-In Timing:
  - June 1, 1998 – Choice of electricity supplier will become available to about 63,000 customers.
  - April 1, 1999 – Choice of electricity supplier will be made available to about 300,000 more customers.
  - April 1, 2000 – Choice of electricity supplier will be made available to about 300,000 more customers.
  - By December 31, 2001 – All customers may choose an alternate electricity supplier.
- Con Edison agreed to auction off at least 50 percent of its electric plants in New York City by the end of 2002. Any fossil generation not sold by that date will be transferred to a deregulated affiliate of Con Edison.

Central Hudson

- Base electric rates frozen at 1993 levels through June 30, 2001, for all customers. (Base rates do not reflect changes in fuel costs.)
- Large industrial customers may choose to continue to buy electricity from Central Hudson and receive a 5 percent per year rate reductions until mid-2001, or they may select an energy services company (ESCO) whose price will be determined by the market.
- Central Hudson's rates for electricity and its delivery will be set by the PSC during the transition to full competition.
- Retail Choice Phase-In Timing (Commercial, Residential and Small Industrial Customers)
  - September 1, 1998 – Choice of electricity supplier will become available to all customers on a first-come, first-served basis, but only up to 8 percent of Central Hudson's total electric load.
  - January 1, 1999 – Choice will become available to customers up to another 8 percent of Central Hudson's total electric load.
  - January 1, 2000 – Choice will become available up to another 8 percent of Central Hudson's total electric load, and on January 1, 2001, up to another 4 percent.
  - July 1, 2001 – Choice of electricity supplier will be available to all Central Hudson customers.
- Central Hudson was required to separate its transmission and distribution (T&D) functions from its generation operations by no later than mid-2001. This restructuring will occur through the establishment of a holding company and the sale of fossil generation plants. The company's costs associated with its share of the Nine Mile Point Two nuclear power plant will remain with the T&D function.
- Central Hudson agreed to auction and transfer its fossil-fueled generating plants by June 30, 2001. The company may bid for the plants through a separate, unregulated affiliate. As an incentive for Central Hudson to maximize the proceeds from the sale of its plants and minimize stranded costs for its customers, the company will be allowed to keep 10 percent of the proceeds above the net book value up to a maximum of $17.5 million if it does not participate in the auction.

O&R

- During 1995 and 1996, O&R's electric rates decreased an average of 4 percent for residential customers and between 4 and 14 percent for commercial and industrial customers.
- On December 1, 1997, residential rates were reduced 1 percent, and they will be reduced an additional 1 percent on December 1, 1998.
- On December 1, 1997, large industrial customer rates were reduced by about 8.5 percent.
- For customers who participate in PowerPick by choosing to buy electricity from an energy services company (ESCO):
  - Large industrial customers may have additional rate benefits in the range of 3.5 percent.
  - Smaller customers may have additional rate benefits in the range of 2 percent.
- Prices for electricity purchased from any ESCO, and from O&R after May 1, 1999, will be determined by the market.
- On May 11, 1998, O&R and Consolidated Edison Company of New York, Inc. (Con Ed) signed a merger agreement under which Con Ed will acquire all of the common stock of O&R. O&R is now a wholly-owned subsidiary of Con Edison. Each company continues to operate under its current name, and their rate and restructuring plans were not affected.
- O&R required to hold an auction to sell its generating plants. The restructuring plan contains financial incentives for O&R to sell them by May 1, 1999.
- O&R will sell electricity only to customers who do not choose to purchase it from an ESCO. As the "provider of last resort," however, it will sell electricity to any customers who switch to an ESCO and then switch back to O&R.

RG&E

- RG&E rates for sale and delivery of electricity set until mid-2002.
- The PSC regulates the utility's rates for delivery after 2002.
- Prices for the generation of electricity after 2002 determined by the market.
- Residential and small commercial customers will receive a 7.5 percent rate decrease phased in over five years.
- Other commercial and most industrial customers will receive an 8 percent rate decrease phased in over five years.
- Large industrial customers will receive a 11.2 percent rate decrease phased in over five years.
- Most customers will see bill decreases. However, some low use electric customers will see a slight increase in their electric bills because increases in the customer charge will not be completely offset by the lower electric rates. All customers pay a "customer charge" regardless of how much energy they use. The customer charge covers the average cost of being connected to the electric system, meters, billing and customer services.
- For residential customers the customer charge has typically been priced below cost. The monthly residential customer charge is being increased $1.50 each year of the plan to approach paying the full cost of service. By tripling the average rate reductions from 2.5 percent to 7.5 percent, the PSC was able to reduce the number of customers affected by the customer charge change.
- Customer access phased in over three years:
  - July 1, 1998 – 10 percent of electricity consumed in RG&E's territory will be open to competition. In addition, new customers or new load will have the ability to choose an alternate supplier.
  - July 1, 1999 – 20 percent of electricity consumed in RG&E's territory will be open to competition.
  - July 1, 2000 – 30 percent of electricity consumed in RG&E's territory will be open to competition.
  - July 1, 2001 – All customers may choose an alternate electricity supplier.
- RG&E will separate its existing combined electric operations into the following different entities: regulated electricity supply company, regulated transmission and distribution

NYSEG

- NYSEG's rates for both supply and delivery of electricity are capped until 2003.
- The PSC will continue to regulate rates for delivery after 2003.
- Prices for electricity for all customers after 2003 will be set by the competitive market.
- In a settlement approved by the PSC, NYSEG has agreed to forgo two previously authorized rate increases, saving customers over $522 million through 2002.
- In addition, the following reductions in NYSEG's rates will apply to customers regardless of whether they stay with NYSEG or choose an energy services company (ESCO) for electricity:
  - Five percent per year rate decrease, for five years, for industrial and large commercial customers with over 500 kW of load capacity.
- Residential and small commercial/industrial customers will have:
  - Rates frozen at the current levels for two years.
  - Bills reduced 1 percent in the third year of the plan.
  - A total decrease of 5 percent by the fifth year of the plan.
- For industrial and commercial customers who are not eligible for the five annual 5 percent rate decreases, the plan provides financial incentives for load growth.
- November 1997 – NYSEG began a Customer Advantage program allowing farms and food processors to buy electricity from a supplier other than NYSEG.
- August 1, 1998 – Choice of electricity supplier will become available to all customers in the company's Lockport Division, the City of Norwich, and to all its industrial customers who are not eligible for the five annual 5 percent rate decreases.
- August 1, 1999 – Choice of electricity supplier will become available to all remaining customers.
- NYSEG agreed to auction its seven coal-fired generation plants by August 1, 1999. The new owners of the plants will compete in the competitive electric generation market.

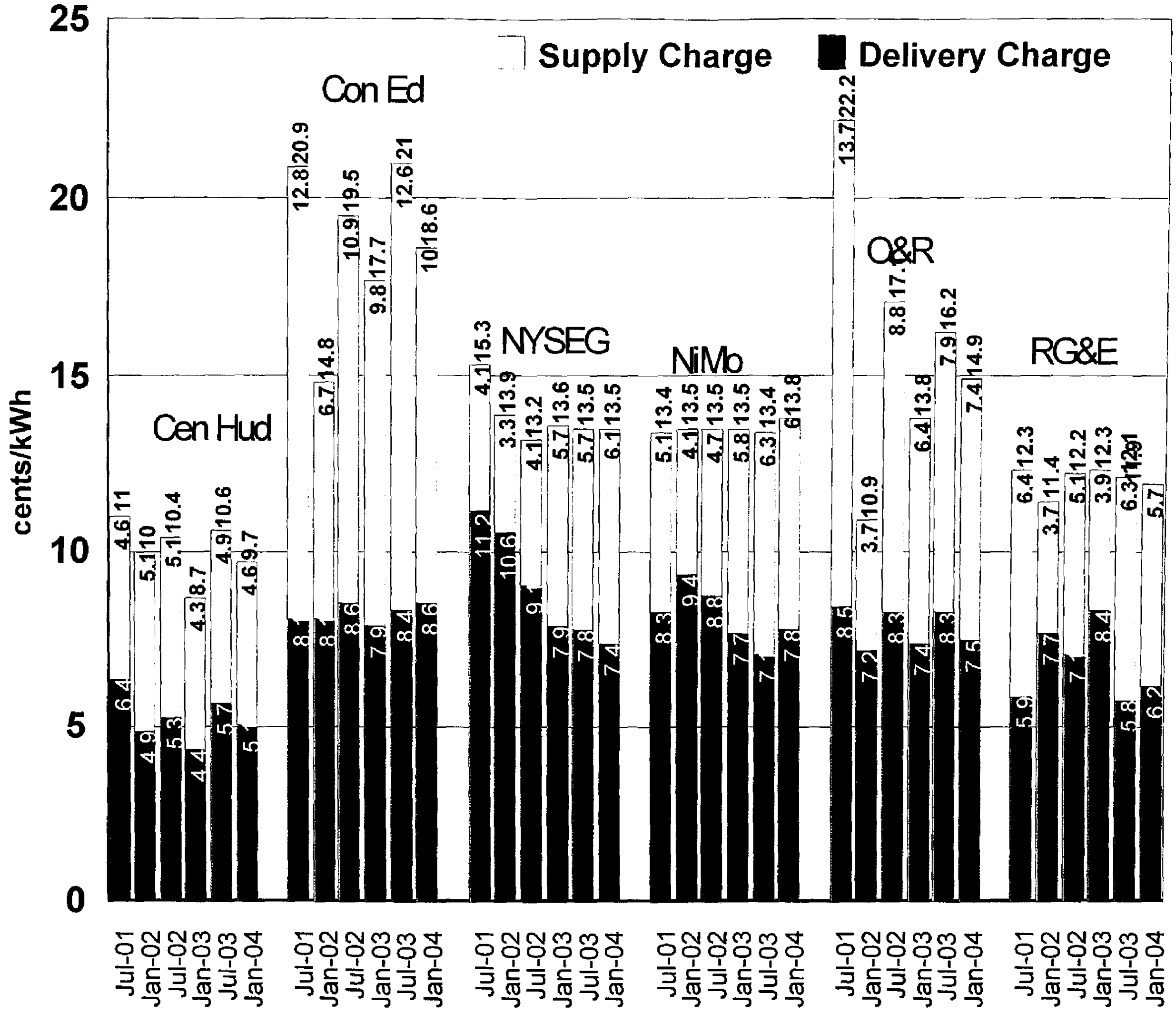
Niagara Mohawk

- Niagara Mohawk's rates will decrease overall by an average of 4.3 percent.
- Residential and commercial customers will see an average phased-in decrease of 3.2 percent over three years.
- Industrial customers will see decreases of about 13 percent.
- Niagara Mohawk rates for electricity and its delivery are set until September 1, 2001.
- In 2001 and 2002, Niagara Mohawk may request limited rate increases, but the PSC must review and approve any request.
- In 2001 and 2002, prices for some of the electricity sold to all customers will fluctuate with changes in market prices.
- November 1, 1998 – Choice of electricity supplier will become available for large industrial and commercial customers who use two or more megawatts of power.
- Retail choice phase-in:
  - April 2 - December 31, 1999 – for residential customers.
  - May 1, 1999 – retail choice will become available for all remaining transmission and sub-transmission industrial and commercial customers.
  - August 1, 1999 – retail choice will become available for all remaining non-residential customers.
- Niagara Mohawk has agreed to remediate pollution on its land, donate 5,000 sulfur dioxide air emission allowances, assist in the development of more than ten megawatts of wind and solar generation, and donate and sell a number of Adirondack land parcels to the state.
- Niagara Mohawk sold its generation capacity and is now a subsidiary of National Grid, a U.K.-based company that also owns electricity distribution operations in New England.

*Source: New York State Public Service Commission,
http://www.dps.state.ny.us/energyarch.htm#facts

Figure IV.3 compares the residential rates for the six major electric companies in New York. The figure shows the delivery charges and supply charges for each company from July 2001 to January 2004. As noted these charges are general categories for the various charges customers pay. The subcategories under the heading of delivery and supply charges are different for each company and the specific amounts of the charges, which are adjusted each month, also vary by company. For example, Central Hudson residential customers' delivery charge is composed of a basic service charge, delivery charge (for transmission and distribution), purchased power adjustment, system benefit charge, customer refund, miscellaneous charges, and taxes. The supply charge is composed of a market price charge, market price adjustment, and taxes. Central Hudson and Con Edison have an adjustment subcategory for both delivery and supply charges. Niagara Mohawk and O&R have the adjustment made on the delivery charge (as noted, for energy market cost changes). NYSEG and RG&E do not have a subcategory for adjustments, however, both the delivery and supply charges, as with all the companies, have changed from month-to-month.

In terms of overall price paid by residential customers, all companies except one have had a decrease in total price per kWh during the period shown in the graph. The exception was Niagara Mohawk, which saw a slight increase.



Data Source: State of New York, Department of Public Service, July 2001 through January 2004.

Figure IV.3. Residential price comparisons by distribution company.

Table IV.1 shows the number of energy service companies (ESCOs) that have met the New York State Public Service Commission's and utility's requirements to provide service to retail customers in the state and the number of companies that are currently serving customers, by distribution company. Some of the ESCOs counted in the table as serving customers currently may not be making offers to new customers at the time when the numbers were collected (June 2004).

Table IV.1. Qualified Energy Service Companies (ESCOs) and those serving residential and non-residential customers, June 2004

	Residential Customers		**Non-Residential Customers**	
Company	Qualified ESCOs	Currently Serving Customers*	Qualified ESCOs	Currently Serving Customers*
Central Hudson	2	2	6	6
ConEd	10	9	19	17
NiMo	12	12	20	19
NYSE&G	10	10	16	15
O&R	7	6	13	12
RGEC	1	1	4	3

*Number of companies that are currently serving retail customers, but may not be currently making offers to new customers.
Source: New York State Department of Public Service, June 2004.

Figure IV.4 summarizes customer switching, or "migration," in New York State and compares May 2002 and 2003 and March 2004 percentages. The top graph in Figure IV.4 is of residential customers, which shows that the most active shopping for these customers in the state is in the Orange and Rockland Utilities and Rochester Gas and Electric service areas.[8] The bottom graphs shows a similar pattern of activity overall for these two companies for non-residential customers, but with high percentages for the large non-residential customers in March 2004 (large non-residential, time-of-use customers[9]) in three other company areas. O&R and Niagara Mohawk had modest gains in the percent of residential customers switching to alternatives from 2003 to 2004. RG&E and Con Edison had declines and Central Hudson, LIPA, and NYSEG were essentially unchanged from 2003 to 2004 for residential customers.

The percent of customer load (MWh) that has migrated to alternative suppliers, as shown in Figure IV.5, is generally higher for non-residential customers than residential load and, except for the Long Island Power Authority's area and Central Hudson's small non-residential customers, are at relatively high levels across the state's service territories. Large non-residential customer load in Con Edison's service area reached nearly 80 percent of load for March 2004, the highest percentage for any area, customer group, and for any year in the state. For residential customers, however, the Orange and Rockland Utilities and Rochester Gas and Electric service areas remain the most active, with all other areas below seven percent in 2004.

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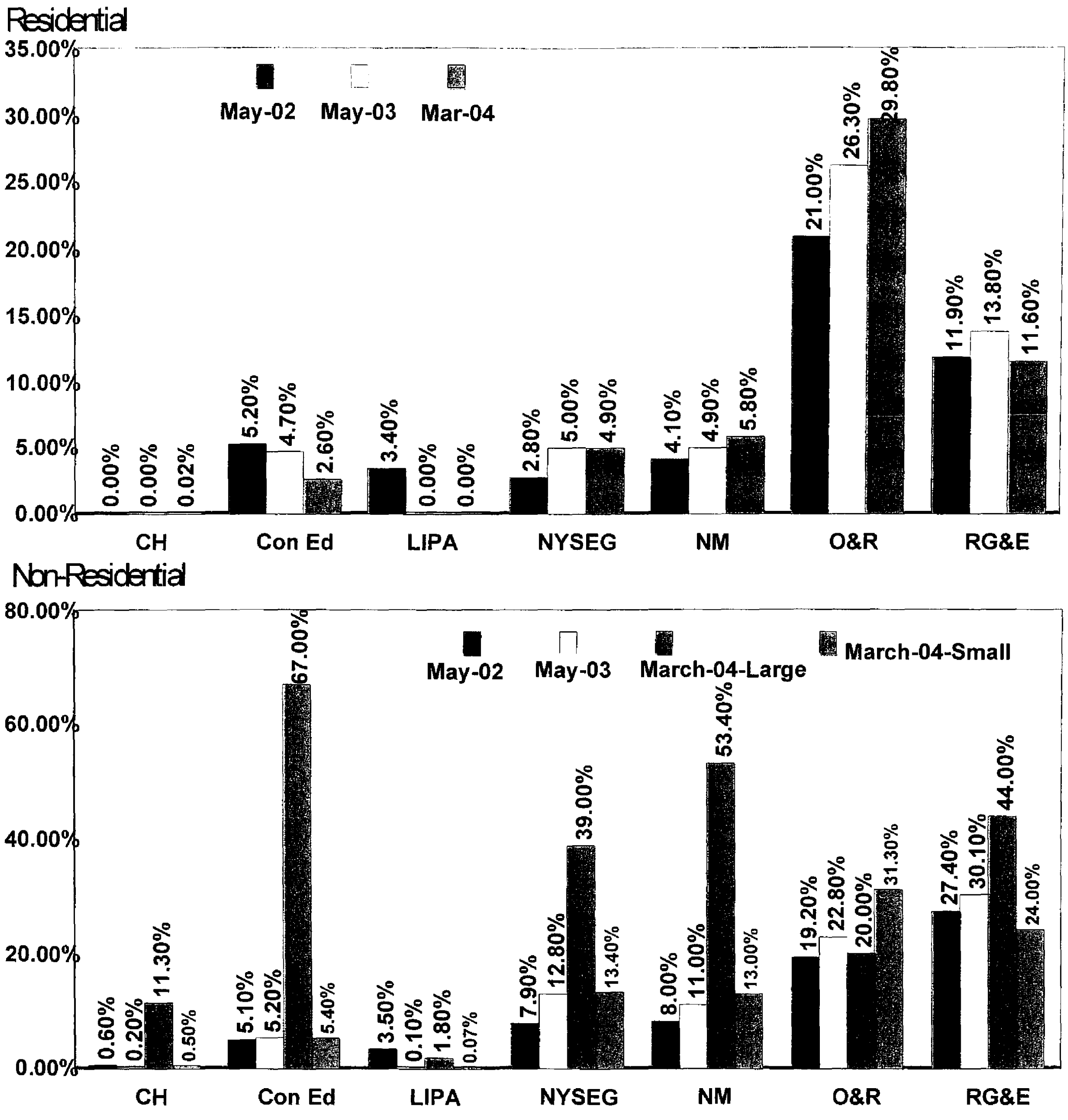
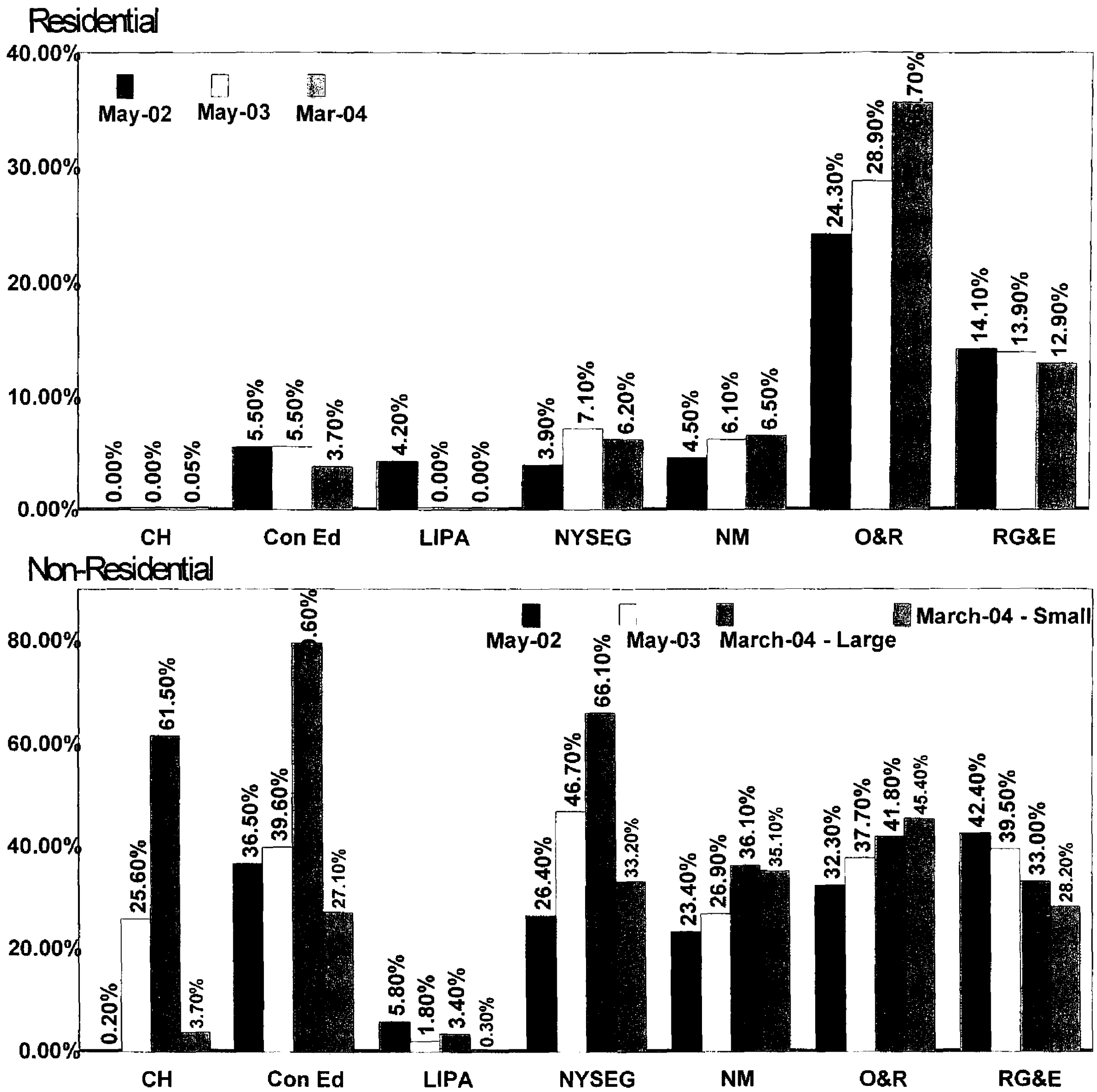
[8]The full company names that are abbreviated in the figures are as follows: CH is Central Hudson Gas & Electric Corp.; Con Ed is Consolidated Edison Company of New York, Inc.; LIPA is Long Island Power Authority; NMPC is Niagara Mohawk Power Corp.; NYSEG is New York State Electric & Gas Corp.; ORU is Orange and Rockland Utilities, Inc.; and RGE is Rochester Gas and Electric Corp.

[9]This customer category was not reported separately in the previous years.



Source: New York State Department of Public Service.

Figure IV.4. Percent customer migration in New York, residential and non-residential customers.



Source: New York State Department of Public Service.

Figure IV.5. Percent load migration (MWh) in New York for residential and non-residential customers.

Section V
Midwest

Wholesale Market

The Midwest is an area that has an extensive transmission system that interconnects the utility systems throughout most of the region. Historically, however, the region has operated as independent utility systems, not as a single tightly coordinated system as other systems in the country have. PJM and New England, for example, operated for a long period as a coordinated system or power pool before they became an ISO. With the transmission system in the Midwest, these independent utility systems have been able to coordinate their systems to support increasing volumes of wholesale sales in the last two decades. However there are some areas with transmission "bottlenecks," that limit the amount of power transfers within the region.

A significant part of the Midwest region formed the Midwest ISO (MISO), which was founded in February 1996, to begin the process of forming a more tightly integrated regional system. MISO became the first FERC-approved RTO in December of 2001 and began operation in February 2002 as a transmission provider and selling transmission service under its open-access transmission tariff. MISO covers an area that has more than 155,000 MWs of generation capacity with more than 97,000 miles of transmission lines. It covers a large area of the country that includes all or parts of 15 states and also one Canadian province, or 1.1 million square miles and 16.5 million customers. Figure V.1 is a map that highlights MISO's geographic area.

Currently, MISO is responsible for short-term reliability and interchange schedules. At this time, the wholesale market transactions in the region are only bilateral trades. While there is currently no centralized energy market, MISO is planning the operational launch of day-ahead and real-time energy markets on March 1, 2005. Market trials are scheduled to begin December 1, 2004. MISO now uses transmission loading relief (TLR) for congestion management, but plans to use Locational Marginal Pricing (LMP, that will be determined in the energy markets) and Financial Transmission

Right (FTR), similar to what other RTOs or ISOs are currently using. MISO also is the provider of last resort for ancillary services.

About 60 percent of the region's capacity are coal-fired power plants. As with the trend nationwide, most of the recent capacity additions use natural gas, which is now about 16 percent of the capacity. The resource margin for the MISO is over 20 percent (the percentage that capacity exceeds peak load).

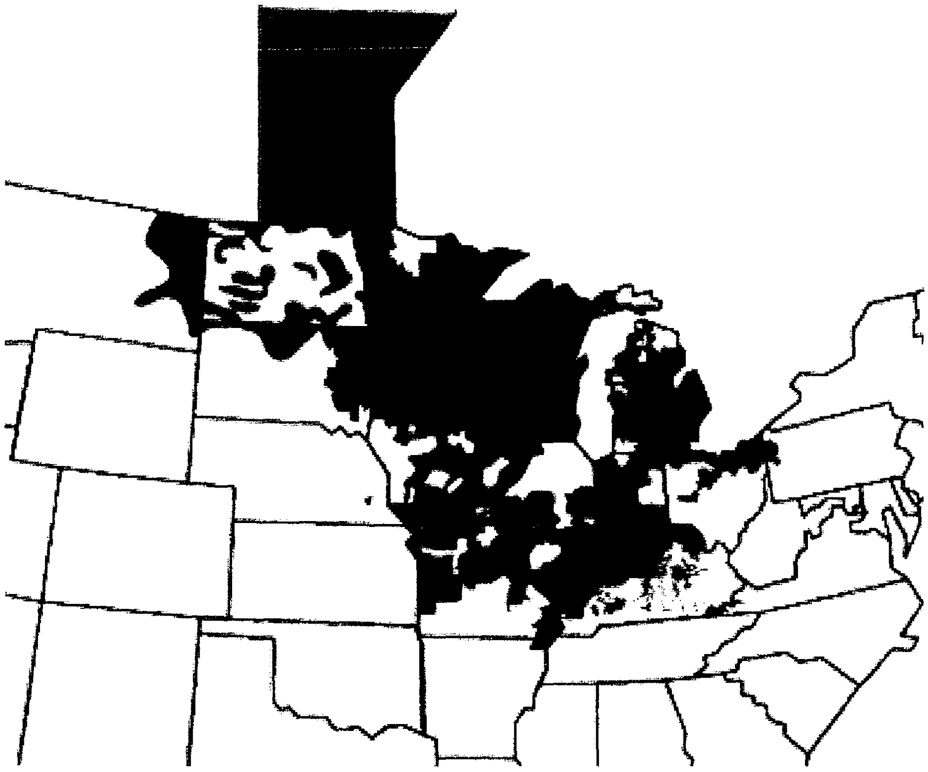


Figure V.1. The Midwest ISO operating region.
Source: Midwest ISO, July 2004.

All of the currently operating and fully functional ISOs or RTOs, New England, New York, PJM, Texas, and California, had previous histories of at least some coordination or are within the boarders of a single state. It is proving to be more difficult to form a functioning RTO over such a sizable area that crosses multiple state lines without this history of close coordination.

MISO and the Southwest Power Pool (SPP) mutually agreed to terminate a merger of their organizations in March 2003. SPP filed with FERC in October 2003 to become an RTO, which FERC conditionally approved in February 2004. SPP made another filing with FERC in May 2004 describing how they plan to meet FERC's conditions.

At this time, MISO, PJM, and SPP are working to form a "joint and common energy market" to coordinate power flows across the three regions.

Midwest Wholesale Prices

Figure V.2 and Figure V.3 plot the weighted average daily prices for several Midwestern trading hubs for January 2003 through April 2004. The data are from Platts, *Megawatt Daily*. Figure V.2 are for the Cinergy (southeastern Ohio), Commonwealth Edison (northern Illinois), and the PJM-western region. The PJM Western region now covers parts of western Pennsylvania and Maryland, northern Virginia, most of West Virginia, into southeastern Ohio, and northern Illinois (there is a map in Section II). The plan is for PJM to extend beyond these areas and include more of the Midwest–including most of Ohio and portions of Indiana and Michigan. Figure V.3 are the mid-continent trading hubs in the western portion of the Midwest area. The hub prices generally move in tandem, but over a wider range than other more centralized and higher volume markets. While natural gas is only about 16 percent of the capacity, since it is the marginal fuel and as in other electricity markets, the impact of natural gas prices in early 2003 and 2004 can again be seen in the price for power.

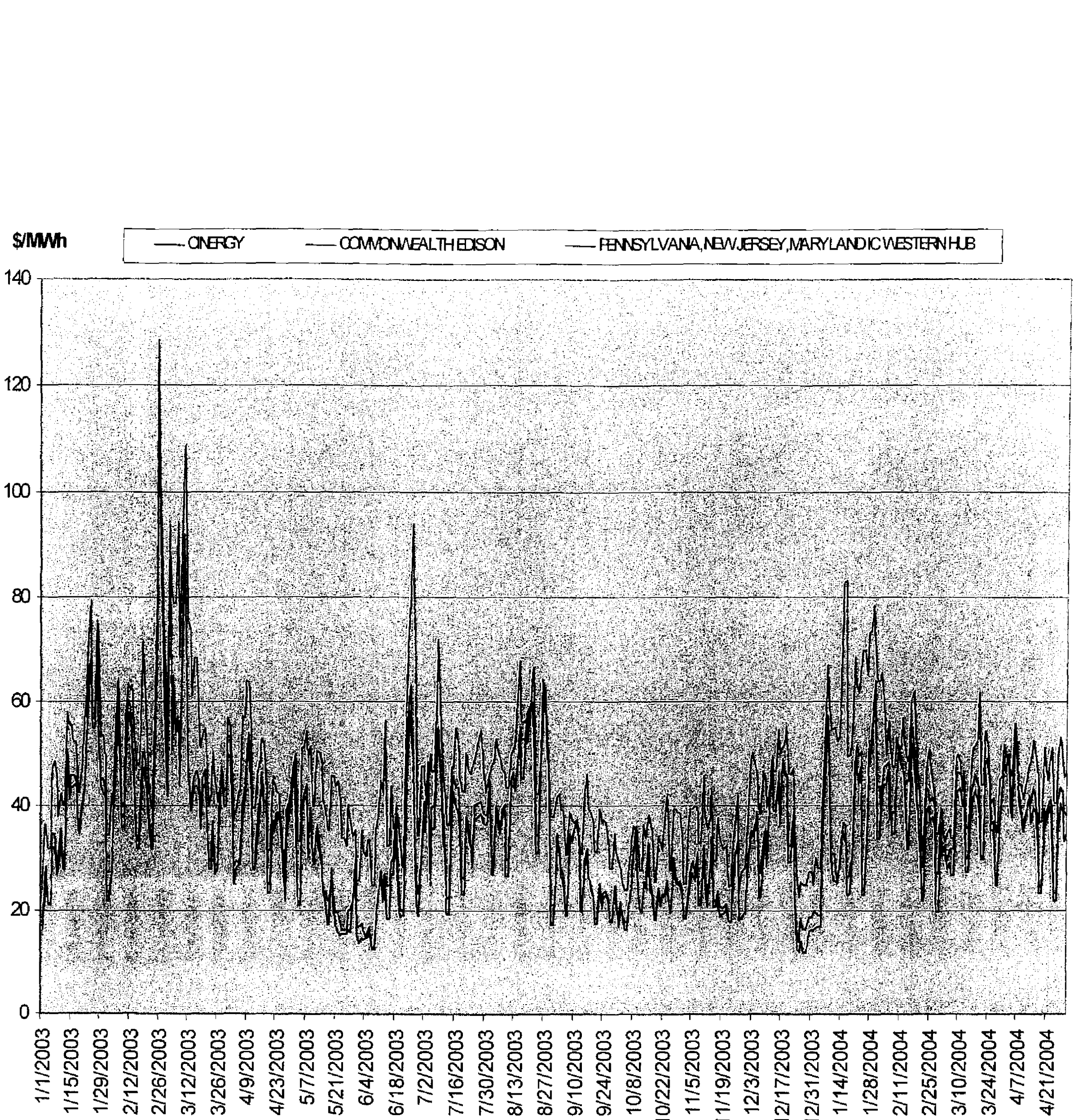


Figure V.2. Weighted average daily prices for three Midwestern trading hubs, January 2003 through April 2004.
Data Source: Platts, *Megawatt Daily*.

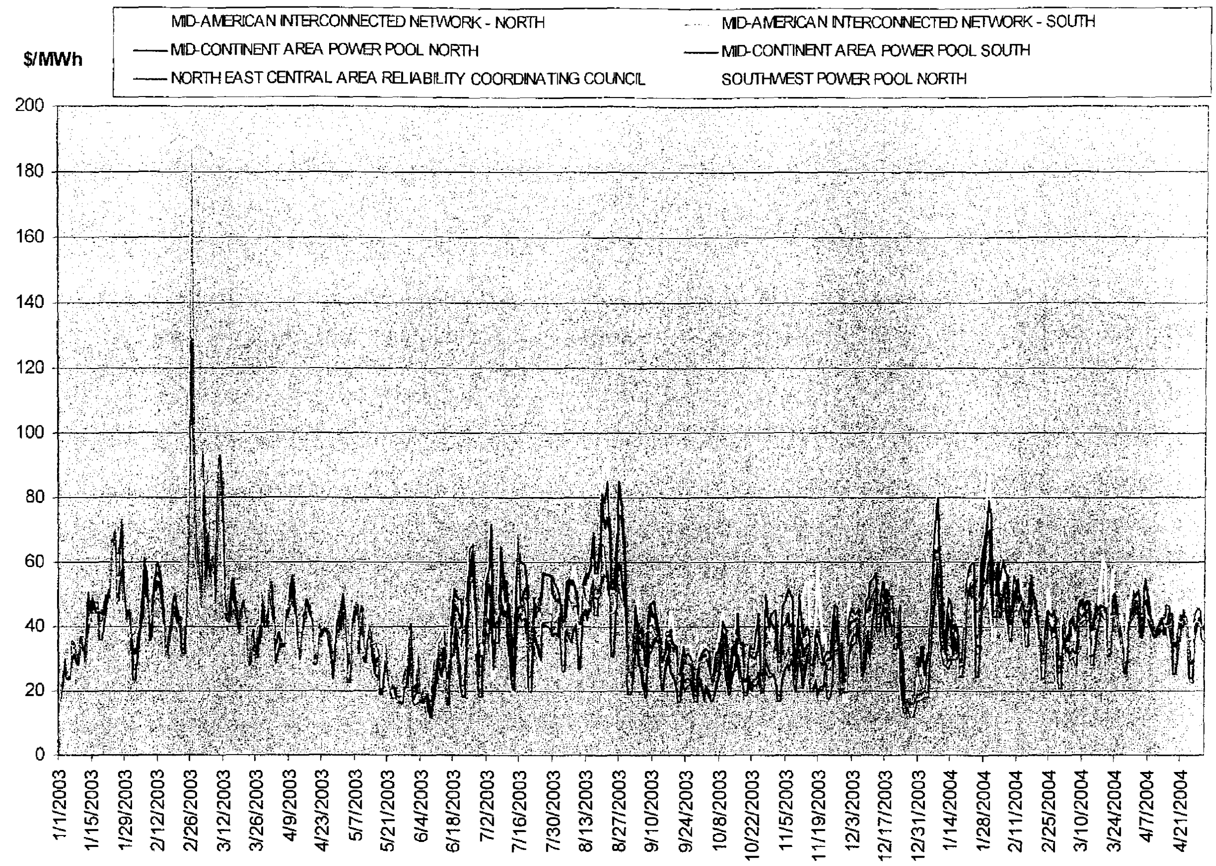


Figure V.3. Weighted average daily prices for six Midwestern trading hubs, January 2003 through April 2004.
Data Source: Platts, *Megawatt Daily*.

Retail Markets

Three states in the Midwest have retail access, Illinois, Michigan, and Ohio. The status of each state is briefly updated below.

Illinois

In December 1997, Illinois enacted into law the Electric Service Customer Choice and Rate Relief Law of 1997. Retail access was phased-in, beginning on October 1, 1999 for approximately 64,000 non-residential electric customers, about one-seventh of all non-residential customers. An additional 609,000 non-residential customers became eligible to choose a new electric supplier on January 1, 2001. Retail access for the approximately 4.4 million residential customers began on May 1, 2002. Currently, all customer classes are eligible to choose an alternative suppliers in the state. Also in May of 2002, the Illinois legislature extended the current freeze on electricity rates until the end of 2006. The Illinois Commerce Commission reports that no supplier has sought permission from the Commission to serve residential customers, consequently, no residential customer have switched to an alternative supplier in the state. The Commission also reports that at the end of 2003, ten suppliers were serving non-residential customers.

Two distribution companies are reporting no activity in their areas for all customer categories in mid 2004, Interstate Power and Light Co. and MidAmerican Energy Co. AmerenUE Co. reported very little activity, one large C&I customer of 39 total customers in the class and two small C&I customers of 7,559 total customers in the class chose an alternative supplier. Three companies, AmerenCIPS Co., Commonwealth Edison Co., and Illinois Power Co., have had some customer switching, primarily among larger customers.

Table V.1 contains the percent of customers that are receiving "delivery services." This includes Interim Supply Service, Power Purchase Option, and Retail Electric Supplier customers. The Illinois Commerce Commission (ICC) defines Interim Supply Service as a tariffed short-term service available to delivery services customers who have no source of electric supply and Power Purchase Option (PPO) as an unbundled, market-based generation option that non-residential customers subject to transition charges must be offered. Both Interim Supply Service and PPO are supplied by the incumbent utility.[1] Currently, according to the ICC, only two utilities, Commonwealth Edison and Illinois Power, charge transition charges to customers who receive delivery services.

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[1]Illinois Commerce Commission, "Assessment of Competition in the Illinois Electric Industry in 2002," April 2003.

The ICC reports that for May 2004 over 42 percent of Commonwealth Edison's delivery services customers were PPO customers. Over 91 percent of Illinois Power delivery services customers were PPO customers, 94 percent of the customers under one MW were taking PPO service. About 67 percent of Illinois Power's larger-use delivery services customers (greater than one MW) switched to PPO.

Table V.2 shows the percentage of delivery service customers using PPO by utility and demand level. The ICC has previously noted that reliance on PPO may be cause for concern for the long-term development of the market, primarily because of the temporary nature of the PPO. They note, however, that electric utilities will cease offering PPO by the end of 2006, when the statutory "Mandatory Transition Period" ends.

Table V.1. Percentage of customers receiving delivery services, May 2004.

	Residential	Commercial	Industrial	Total		
AmerenCIPS Company	0.0%	1.0%	28.2%	0.2%		
	Residential	Small C&I	Large C&I	Govern mental	Other	Total
Commonwealth Edison Company	0.0%	5.4%	74.6%	2.9%	1.0%	0.6%
	Residential	Demand Less Than 1 MW	Demand Greater Than 1 MW	Total		
Illinois Power Company	0.0%	1.5%	40.3%	0.2%		

Source: Illinois Commerce Commission, May 2004.

Table V.2. Percentage of Delivery Service Customers on Power Purchase Option, May 2004.

Utility	Less Than 1 MW	Greater Than 1 MW	Total
Commonwealth Edison Co.	43.0%	33.6%	42.6%
Illinois Power	93.9%	67.0%	91.6%

Source: Illinois Commerce Commission, May 2004 update.

Michigan

Michigan started retail access for all customers of Michigan investor-owned utilities on January 1, 2002. Table V.3 shows the percent of sales that have switched to alternative suppliers for Michigan's two largest investor-owned companies, which together provide service to almost 90 percent of the state's electric customers. While there is almost no activity among residential customers, there has been activity with larger customer groups, particularly with industrial customers in both companies' territory and with commercial customers in Detroit Edison's territory.

Table V.3. Percent of sales (MWh), end of first quarter 2003 and November 2003.

	Consumers Energy		Detroit Edison	
	2002	Nov. 2003	2002	Nov. 2003
Residential	0.000%	0.000%	0.005%	0.007%
Commercial	4.7%	6.7%	10.7%	20.3%
Industrial	10.4%	16.0%	8.8%	16.3%
Total	5.3%	8.2%	7.3%	15.0%

Source: Michigan Public Service Commission, "Status of Electric Competition In Michigan," February 1, 2004.

Ohio

Ohio's restructured electric generation market began January 1, 2001. The state remains in a transition period or a "market development period," which for most utilities continues until the end of 2005, during this time incumbent distribution utilities continue to provide standard offer service to customers who do not choose an alternative supplier and to those customers whose chosen supplier defaults in providing service. Also during this period customers receive standard offer service at prices approved by the Public Utilities Commission of Ohio (PUCO) and residential customers receive a five percent rate reduction on the distribution utility's unbundled generation service component. After the market development period, standard offer service may be provided at market rates, that could be obtained by competitive bidding for either the customer accounts or the load. A distribution utility, that offers both competitive and non-competitive services, is required to form separate affiliates and meet accounting requirements determined by the PUCO. The utility needs to obtain approval of the PUCO for the corporate separation plan.

In August 2001, the PUCO approved rules for allowing electric demand aggregation by local governments. These rules require local governments to obtain majority support of the community to act as an aggregator. Under Ohio's law the customers are automatically enrolled with the community's chosen supplier unless a customer returns an "opt-out" card mailed to all eligible customers. The North East Ohio Public Energy Council (NOPEC) formed an electric buying group that represents 112 communities in Northeast Ohio with more than 350,000 residential customers in eight counties. This is the largest public aggregation of electricity customers in the U.S.

The percentages of customers that switched to an alternative supplier for each distribution company is shown in Figure V.4. Cleveland Electric Illuminating Company[2] had the highest percentage of all customers switching to alternatives of Ohio electric distribution companies and for all customer classes except industrial. Switching of its residential, commercial, and for total customers were all above 70 percent for each category. Toledo Edison had the highest percentage of industrial customers at almost 66 percent. Toledo Edison also had a relatively high percentage of other customers switching, with residential, commercial, and total customer categories at almost 50 percent or greater switching to alternative suppliers. All of the Ohio Edison customer categories were above 30 percent. For the other five distribution companies, no category exceeded six percent customer switching, except for industrial customers of Dayton Power and Light, with was above 16 percent. Columbus Southern Power, Dayton Power and Light, Monongahela Power, and Ohio Power Company reported no

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[2]The full company names of the abbreviations used in the figures are as follows: CEI, Cleveland Electric Illuminating Co.; CG&E, Cincinnati Gas and Electric Co.; CSP, Columbus Southern Power Co.; DP&L, Dayton Power and Light Co.; Mon Pwr, Monongahela Power Co.; Ohio Ed, Ohio Edison Co.; Ohio Pwr, Ohio Power Co.; TE, Toledo Edison Co.

residential customers had chosen an alternative supplier. Cincinnati Gas and Electric had less than four percent residential customer switching.

In terms of megawatt-hour sales, shown in Figure V.5, the pattern is similar for Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison, except for industrial sales for Toledo Edison that was below four percent. Also, there was considerably more activity for commercial and industrial sales for Cincinnati Gas and Electric and for Dayton Power and Light. Dayton Power and Light industrial sales percentage was the highest of any distribution company, at over 64 percent. It should be noted that Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison (all part of FirstEnergy Corporation serving northern Ohio) had the highest regulated rates among investor-owned utilities prior to restructuring and, consequently, higher prices-to-compare than other parts of the state.

Customer aggregation by local governments in the area of Toledo and by Northwest Ohio Aggregation coalition and NOPEC in other areas contributed to substantial switching in the services areas of Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison. As of March 2004, aggregation programs account for almost 95 percent of residential, almost 88 percent of the commercial and only just under seven percent of the industrial customer switching in Ohio and almost 94 percent of all customer switching in the state. Table V.4 summarizes the aggregation program switching.

Table V.4. Aggregation activity in Ohio, March 2004.

	Customer Switching through Aggregation	**Total Customer Switching**	**Percent Switching through Aggregation**
Residential	853,229	899,527	94.85%
Commercial	104,737	119,523	87.63%
Industrial	119	1,731	6.87%
Total	958,085	1,020,781	93.9%

Source: Source: Public Utilities Commission of Ohio, Division of Market Monitoring & Assessment.

As noted in previous years' Performance Reviews, under an agreement with the PUCO and various parties, FirstEnergy agreed to make available 1,120 MW of "Market Support Generation" (MSG) to non-affiliated marketers, brokers and aggregators for sales to retail customers during the "market development period," which runs for five years beginning January 1, 2001. This capacity was made available on a first-come-first-served basis to competitive suppliers for committed capacity sales to FirstEnergy's customers. Of the total MSG capacity, 500 MW is reserved for residential customers. Total power allocations for the three northern Ohio FirstEnergy companies are 560 MW from Ohio Edison, 400 MW from Cleveland Electric Illuminating, and 160 MW from Toledo Edison. Prices for the capacity are based on customer class and increase each year that the capacity is made available. Industrial and commercial customer prices are the same for all three FirstEnergy companies, beginning at $26.23/MWh and $30.83/MWh respectively in 2001 and rising to $31.88/MWh and $37.19/MWh respectively in 2005. Residential customer prices for the MSG capacity are $30.03/MWh for Toledo Edison, $31.19/MWh for Ohio Edison, and $31.64 for Cleveland Electric Illuminating. These prices rise to $36.28/MWh, $37.69/MWh, and $38.24/MWh respectively in 2005. It is believed that these prices are initially below market prices for each customer class.

At this time there is only one offer being made to residential customers in one distribution company's territory, Cincinnati Gas and Electric–from Dominion Retail, Inc. No other offers are currently being made to residential customers in any other part of the state. The total number of residential offers has decreased from eight in January 2001, three in May 2002, one in 2003, and again one currently being made (July 2004).

The PUCO issued an order in June 2004 that requires a competitive bidding process to be conducted by a third party administrator for all of FirstEnergy's customer load. This is to test if there is sufficient competition among electricity suppliers to find a lower generation price than what FirstEnergy is now charging. If the bidding process does find lower generation rates, the accepted bids would determine rates offered to customers through 2008. If the bidding process does not find a lower cost supplier, then

FirstEnergy's current rates will continue and remained capped through 2008 – which extends the rate caps another three years. An annual bid will be conducted to determine if lower generation rates are available through the electricity market. The Competitive Transition Charge (CTC) will continue to be collected by FirstEnergy from consumers, which were originally set to expire at the end of 2005. The PUCO also found that FirstEnergy could only raise rates to cover any increases in taxes.

The PUCO modified this decision in August 2004 and FirstEnergy has indicated that it will implement the modified PUCO Rate Stabilization Plan. The changes include allowing an adjustment in generation rates when FirstEnergy's fuel costs increase and extending the MSG as a "backstop" if fewer than 20 percent of FirstEnergy customers are enrolled with competitive suppliers. Also part of the agreement, the competitive bid is to be conducted in December 2004 and the PUCO can end the plan with a one year's notice for any reason.

In the FirstEnergy case, the PUCO was concerned that the wholesale market had not developed sufficiently to end the rate caps as planned at the end of 2005. The Commission notes that when the state's restructuring law was passed,

> . . . it was assumed that a regional market would develop quickly and that the retail markets would follow. This is why the law provided for the five-year market development period (MDP). Thus far, the electric marketplace has not developed as hoped.[3]

The "rate stabilization plans" filed by FirstEnergy and other Ohio utilities, are intended "to help ensure that electric consumers do not face 'sticker shock' from electric rates when the market development period ends on December 31, 2005."[4] The PUCO is considering rate stabilization plans for the remaining Ohio utilities that have not already had one approved.

There are informal and preliminary discussions among various interested parties in Ohio on what the next steps should be beyond the rate stabilization plans. While there

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[3]Public Utilities Commission of Ohio, "FirstEnergy and the End of the Market Development Period: Frequently Asked Questions," at www.puco.ohio.gov.

[4]PUCO, "FirstEnergy and the End of the Market Development Period," ibid.

are currently no formal discussions with the PUCO or among Ohio legislators, in February 2004, the AEP companies in Ohio (Columbus Southern Power Company and Ohio Power Company) filed an application for approval of their "post market development period rate stabilization plan" that did make a recommendation to the PUCO for a formal process. AEP stated:

> The [AEP] Companies believe that by the end of the Rate Stabilization Period [RSP], the competitive market for electric generation service will more closely resemble what the Ohio General Assembly envisioned, when it enacted S.B. 3, as being in place by the end of the [market development period] MDP. However, there are no assurances that such a market will exist by the end of the RSP. Therefore, it is recommended that the [Ohio] Commission conduct a proceeding to determine the manner in which electric generation service should be provided to the Companies' customers after the conclusion of the Plan. The Commission should consider various options ranging from a 'flash cut' completion of the transition to competition, to returning to traditional cost-of-service regulation. It is further recommended that the Commission complete and report the results of this proceeding to the Ohio General Assembly no later than December 31, 2005 so that sufficient time will be available for the consideration and enactment of any legislation which might be needed. The report would include recommendations to the General Assembly. Before making such recommendations, the Commission should provide an opportunity for input by all interested parties.[5]

This reflects a general view among many in the state that more formal discussions are necessary to consider possible needed changes to the state's restructuring law, in view of the less than favorable market conditions (for consumers) that could persist through the end of 2008, when the rate stabilization plans expire. This also reflects the view of some that significant modification or even a reversal of the restructuring course may be necessary.

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[5]"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post Market Development Period Rate Stabilization Plan," Case number 04-169-EL-UNC, PUCO file date February 9, 2004; from item number 8 on pages 13 and 14.

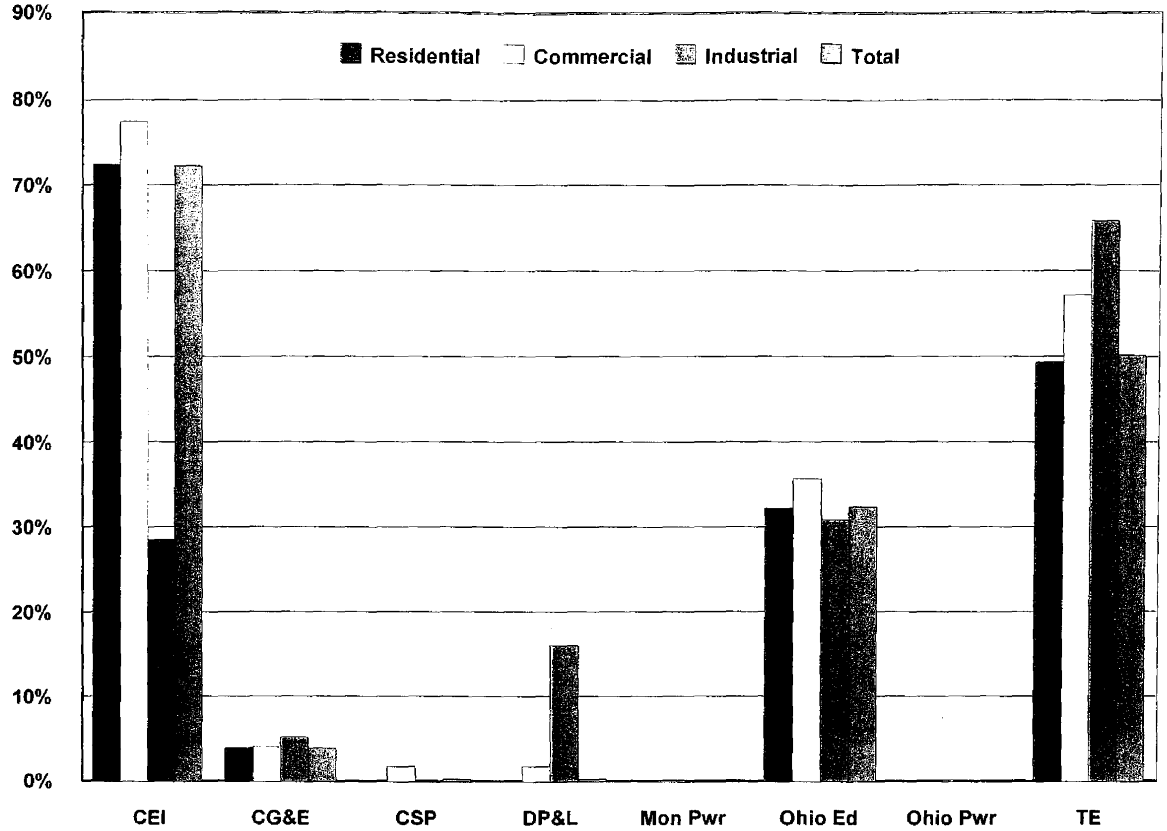

Figure V.4. Percent of customers that switched to alternative electric suppliers, March 2004.
Source: Public Utilities Commission of Ohio, Division of Market Monitoring & Assessment.

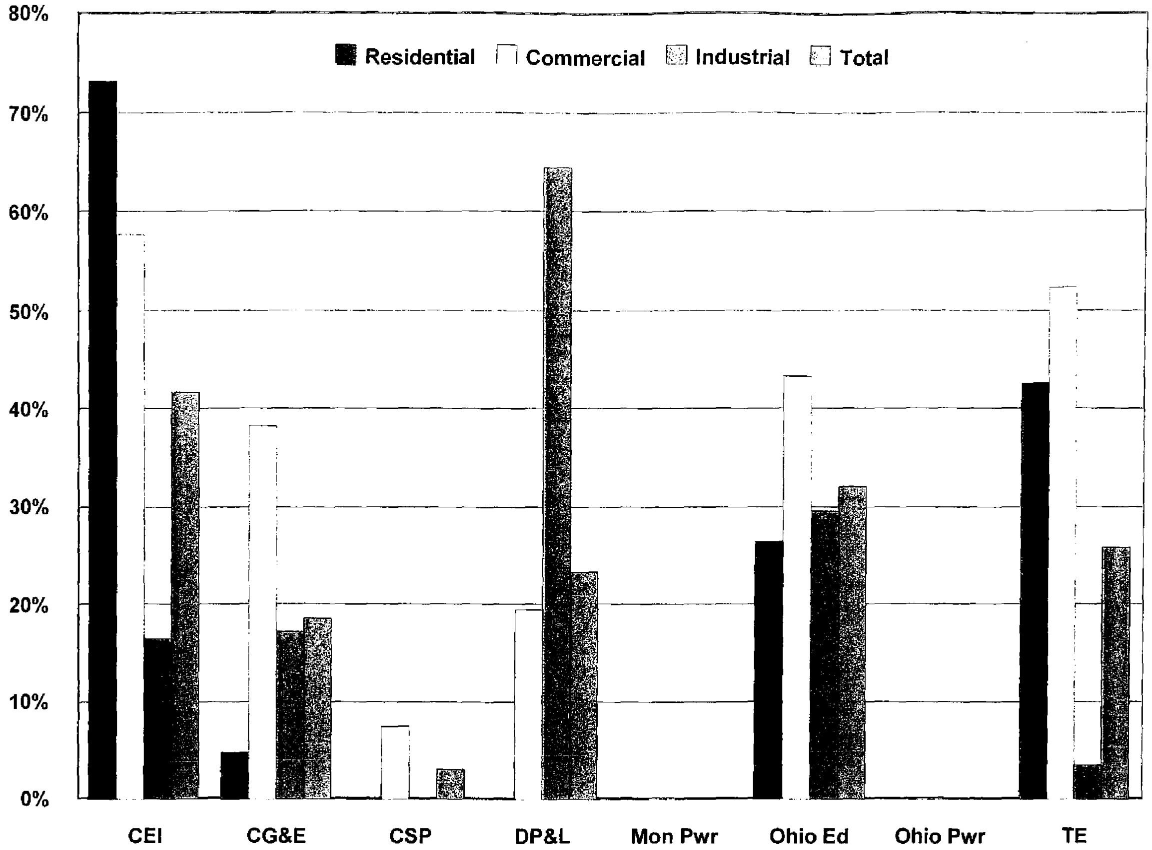

Figure V.5. Percent of megawatt-hour sales that switched to alternative electric suppliers, March 2004.
Source: Public Utilities Commission of Ohio, Division of Market Monitoring & Assessment.

The following is a summary of the Stipulation and Recommendation entered into by FirstEnergy and several interest groups that became the settlement accepted by the PUCO to implement restructuring in northern Ohio.

Summary of Transition Costs Treatment in the FirstEnergy "Stipulation and Recommendation"

<u>Terms used in the Stipulation and in this summary</u>:

RTC: Regulatory Transition Charge; charge to customers for unrecovered regulatory costs associated with regulatory assets, such as deferred expenses.

GTC: Generation Transition Charge; charge to customers for generation costs deemed to be uneconomic or unrecoverable in a competitive generation market.

Transition Costs: The term used and defined in S.B. 3 (restructuring legislation) to refer to costs incurred by regulated utilities to serve their customers that may not be recoverable in a competitive market. Also called "stranded costs " and includes regulatory and generation costs.

Generation or "little g": The determined economic generation plant, or what was determined to be recoverable in the market. For the FirstEnergy companies, this was calculated for unbundling purposes only and not used to calculate the "Shopping Credits."

Discount: A 5 percent discount off the generation cost mandated by S.B. 3. Calculated in the Stipulation as 5 percent of the sum of generation ("little g"), the RTC, and the GTC, or "Big G."

Market Development Period: January 1, 2001, the beginning of retail access, to December 31, 2005.

Shopping Credit: The "credit" back to a customer if they purchase power from another supplier. The shopping customers' new price for generation is then the price they pay their new supplier. The shopping credit is the amount that the customer uses to compare competitive offers, or the "price-to-compare."

MSG: Market Support Generation; the 1,120 MW of generating capacity made available by the three FirstEnergy companies (Ohio Edison, Cleveland Electric Illuminating, and Toledo Edison) to non affiliated marketers, brokers, or aggregators (not affiliated with any Ohio investor-owned utility) for sales to retail customers during the market development period, as allocated by company and customer class in the stipulation.

MSP: Market Support Price; the price for MSG as set in Attachment 2 in Megawatt hours.

Shopping Credit Incentive: Percentage used to calculate the shopping credit during the Market Development Period, from Attachment 3, and is based on the fixed MSP.

A Numeric Example

Figure V.6 below was drawn using the 2002 average unbundled rate components for Ohio Edison's residential class customers provided by the PUCO staff and the 2002 Shopping Credit with Incentives found in Attachment 3 of the FirstEnergy "Stipulation and Recommendation" for the same company and customer class. This is intended to be an illustrative example, not the exact amount residential customers in Ohio Edison's territory actually pay. The actual rates are divided by subclass (residential standard, residential space heating, etc.), the season (winter, summer), usage (amount of kWhs used), customer charges (a fixed charge that varies by subclass), and year applied. This is the situation for the market development period that began January 1, 2001 and continues through December 31, 2005.

The first column in Figure V.6 is the unbundled rate for residential service. The charge for distribution and transmission are fixed, but can be altered under certain circumstances–adjusted for Regional Transmission Organization (RTO) participation costs, for example. The RTC charge, or the Regulatory Transition Charge, to recover regulatory assets extends beyond the Market Development Period and may also be adjusted over time. The GTC in the first column is the fully allocation charge for uneconomic generation. Paid out over time and with no customer switching to alternative suppliers, this would allow the company to recover past generation costs that were believed to be unrecoverable in a competitive market. The generation portion, or "little g," is the generation cost that could be recovered in the market or the "economic plant."

For customers that do not choose an alternative supplier and remain with their utility, in this example they pay the total bundled price of 10.2 cents per kWh. A customer that chooses an alternative supplier pays the same unbundled rates, as shown in the second column, for distribution, transmission, and RTC, but the generation price is now the new supplier's price. If a customer can find a price below the "Shopping Credit,"

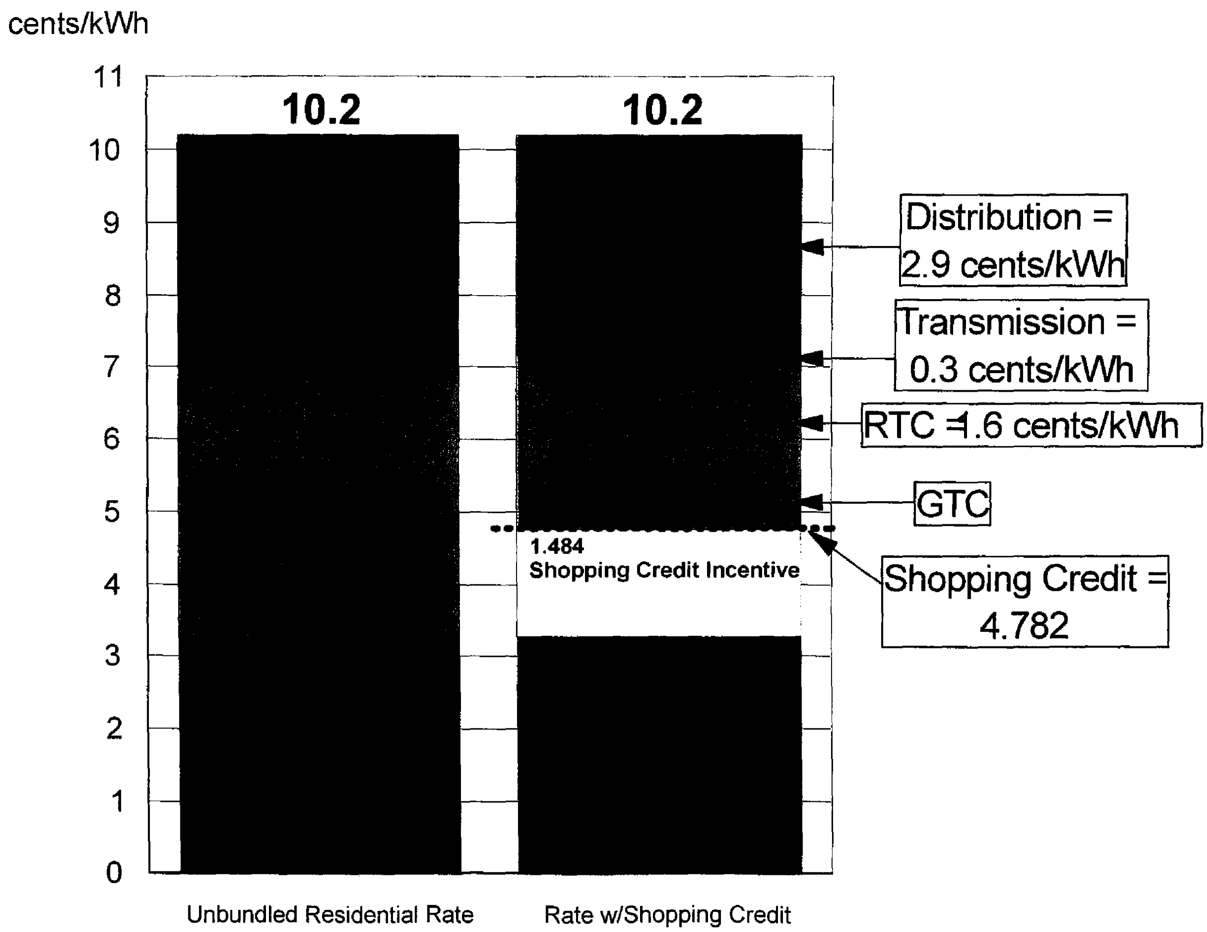

Figure V.6. Numeric example of FirstEnergy "Stipulation and Recommendation" mechanism.
Source: authors construct from the term of the agreement and PUCO staff numbers.

in this example, below 4.782 cents per kWh, the customer's savings would be the difference between the shopping credit and the new price for generation. For example, if a customer purchased power for four cents per kWh, they would save 0.782 cents per kWh and would pay a total bundled price of 9.418 cents per kWh.

For FirstEnergy, for customers that remain with them, they collect the entire GTC along with all the other charges (column one in the figure). For customers that switch to an alternative supplier for their generation, FirstEnergy now collects the reduced GTC plus the same RTC and the transmission and distribution charges. The difference between the market support price and the shopping credit, or the shopping credit incentive as shown in yellow in the figure, is deferred for recovery past the end of the market development period and is to be recovered as an adjusted RTC. Specific dates are set for each company for when the RTC recovery period should end, unless additional time is needed to amortize the deferrals when more than 20 percent of any customer class by company has switched or from a "substantial deviation" in the estimated sales due to changing economic conditions.

The legislative mandated 5 percent discount is calculated based on the generation component ("little g"), the RTC and the GTC (together referred to as "big G"). The total rate shown in Figure V.6 has the discount already deducted.

There is also a "Transition Cost Recovery Incentive" that would reduce the period of recovery of the RTC for up to $500 million if a class of customers by company has not reached 20 percent by the end of the market development period. Amounts by company and other details are in the Stipulation.

Section VI
SOUTH AND SOUTHEAST

Wholesale Markets in the South and Southeast

There are no operational ISOs or RTOs in the southeast region at this time. Three RTOs have been proposed over the last several years. In 2000, Progress Energy (Carolina Power & Light), Duke Energy, and SCANA began the formation of GridSouth RTO and filed a plan with FERC to operate the RTO in the North and South Carolina region. FERC later encouraged and mediated discussions with other southeastern transmission organizations to create a single regional RTO. However, due to a lack of consensus on which model to follow for the region, GridSouth suspended its implementation activities in June 2002.

Transmission owners in Alabama, Florida, Geogia, Mississippi, and South Carolina (including the region's largest transmission owners, Entergy and Southern Company) began the formation of the SETrans RTO in 2001. However, also citing a lack of consensus and support in the region, development activity on the RTO was suspended in December 2003, which was decided unanimously by the sponsors.

Also in 2000, Florida Power & Light, Progress Energy (Florida Power Corp.), and Tampa Electric Company, formed GridFlorida and filed with FERC to become an RTO. Provisional RTO status was granted by FERC in March 2001, provided GridFlorida continued to discuss interregional coordination with neighboring transmission organizations. Due to objections by the Florida Public Service Commission, GridFlorida refiled with FERC to become a not-for-profit entity in December 2001. Discussions between GridFlorida, FERC, the Florida PSC, and other interested parties continued into late 2003.

While there are no functioning ISOs or RTOs in the region, there are wholesale transactions for power delivered into the major companies and areas in the region. Figure VI.1 graphs *Megawatt Daily*'s volume weighted-average (peak hour) price indices for five areas in the south and southeast region, for deliveries into Entergy, Southern Company, Tennessee Valley Authority, Florida, and the Southwest Power Pool. This covers a wide and diverse area, which may explain the disparity between the higher prices into Florida (with relatively higher generation costs in the region) versus the lower prices for the Southwest Power Pool. As seen in other regions, all five price indices responded to the spike in natural gas prices seen in early 2003 (the natural gas price spike in early 2004 was mainly limited to the northeast, as seen in the New York prices in Figure I.3 of Section I).

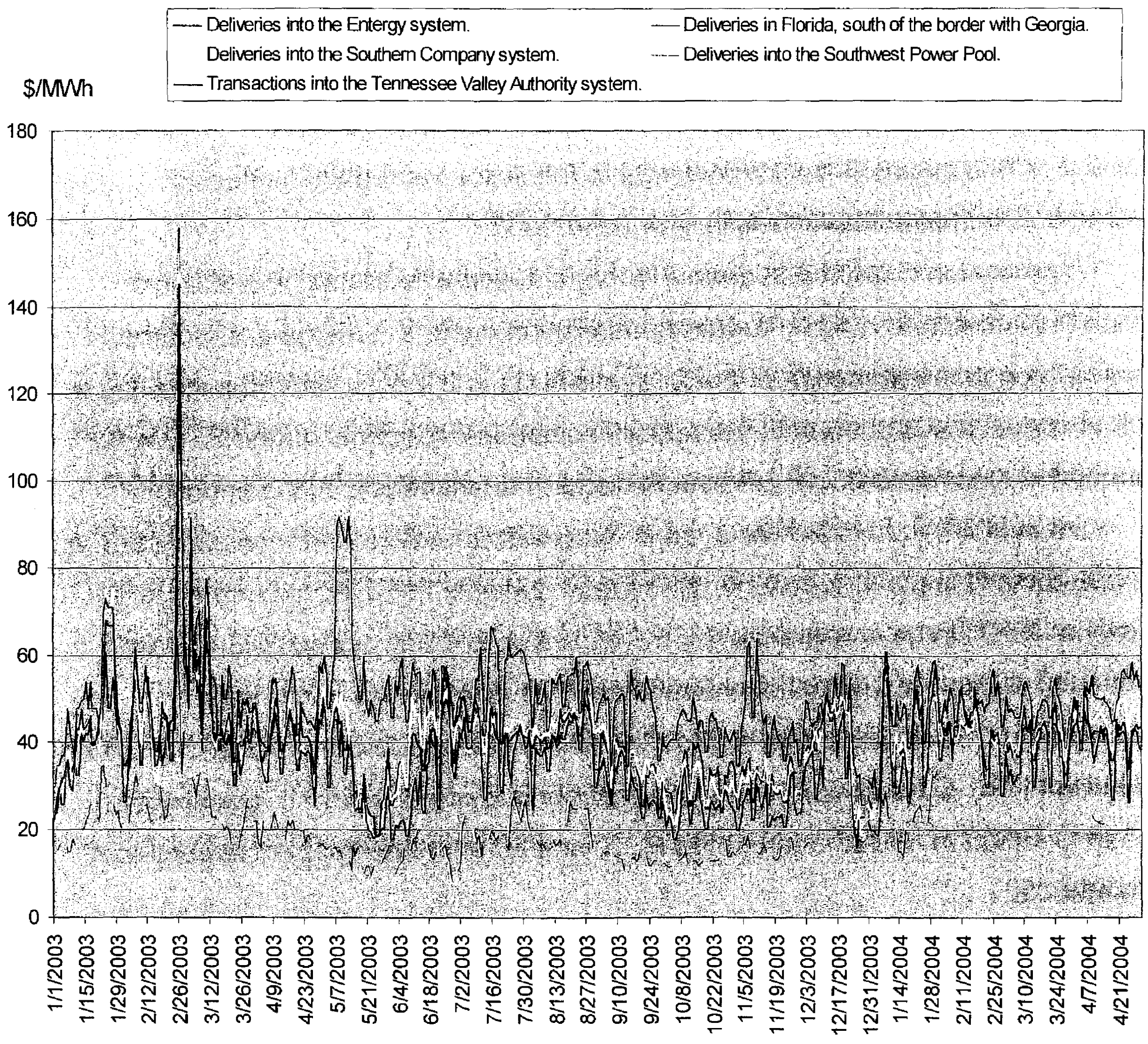

Figure VI.1. Daily weighted-average wholesale power prices in the southeastern region. Data Source: Platts, *Megawatt Daily*.

A case currently before the Georgia Public Service Commission and FERC has important implications for both the region and FERC policy on utilities' ability to use their ratepayers to hedge their competitive risks. The case before the Georgia PSC is a request by Southern Company's two Georgia utilities to recover $563 million for the cost of two power units outside Savannah.[1] The two McIntosh gas-fired units are still under construction and are located next to an existing coal-fired plant. FERC has been investigating alleged bidding irregularities by Southern Company, its two Georgia utility affiliates, and Southern Power, an affiliated wholesale power company that sold the two McIntosh units to Georgia Power and Savannah Electric in May 2004. Southern Power, the Southern Company subsidiary, began building the units after winning a competitive bid in late 2001 to sell wholesale power to Georgia Power and Savannah Electric.

The state PSC approved the purchased-power contracts in 2002. Southern Co. then submitted them to the FERC for approval. But competitors challenged the contracts, arguing that Southern Company used overlapping affiliates to favor Southern Power and asked FERC to reject the contracts. Competitors and FERC staff found evidence that Southern Company had been, at best, "sloppy" about conflicts of interest and had provided its own bidder with advantages.

The Georgia PSC decided to allow Georgia Power and Savannah Electric to buy the plants from Southern Power and recover the cost from ratepayers, but will decide later the dollar amount to be recovered. The PSC is also considering new rules on bidding for purchased power and transactions between affiliates. Southern Company canceled the Southern Power contracts and withdrew its application for FERC's approval a week before a hearing was to begin. While the sale of the units would take them out of FERC's control and transfer them to the Georgia PSC, FERC staff recommended that the investigation of Southern Company's bidding behavior continue. In addition, in a rate case, Georgia Power is seeking its first rate increase in 13 years.

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[1]The facts of the pending cases were primarily from "Georgia Power Users Could Foot Big Bill," by Margaret Newkirk, The Atlanta Journal-Constitution, June 12, 2004, distributed by Knight Ridder/Tribune Business News.

Retail Markets

While several states in the southeast have studied whether to adopt retail access or had legislative proposals, no state in the region has adopted retail access and there are currently no formal actions to do so.

Section VII
TEXAS

Due to the apparent early success of its retail markets, Texas has attracted a great deal of attention across the country. Since its beginning in January of 2002, the Texas retail market has been one of the more active in terms of offers to residential customers and savings opportunities. This early success has led some to proclaim Texas as the model for both its retail access program and its wholesale market design. This section is an abbreviated version of last year's (2003) Performance Review of the Texas market, with updated information on wholesale prices, customer switching, and residential choices.

Wholesale Market and the Electric Reliability Council of Texas

The Electric Reliability Council of Texas, Inc. (ERCOT) administers Texas' power grid and serves approximately 85 percent of the state's electric load, an area that includes about twelve million people. ERCOT is an independent, not-for-profit organization responsible for the transmission of electricity and is one of ten regional reliability councils in the North American Electric Reliability Council (NERC). ERCOT has approximately 78,000 megawatts of generation and over 37,500 miles of transmission lines. ERCOT covers approximately 75 percent of the land area in Texas.

The Texas Public Utility Commission (the Commission or Texas PUC) has primary jurisdiction over ERCOT activities and, because ERCOT is located completely within the borders of a single state, FERC does not have any jurisdiction. Some believe that this provides Texas with a better opportunity to coordinate the ERCOT portion of the state's retail and wholesale markets since both are state jurisdictional and the FERC is not involved. Outside of the ERCOT region, transmission access and pricing and wholesale generation markets are under the jurisdiction of the FERC. Retail pricing and market operations remain under the jurisdiction of the Texas Public Utility Commission.

In May 1999, the Texas Legislature passed a bill to allow electric choice or retail access, which began for most consumers in January 2002. This required ERCOT to change its structure and functions. ERCOT is still responsible for transmission reliability and open wholesale access, but is also charged with overseeing the transactions related to the state's restructuring of the electric industry–including the development and operation of the ERCOT portion of Texas' competitive retail market.

ERCOT's market relies primarily on bilateral contracts between buyers and sellers of electricity traded. In contrast to other markets in the U.S. where there is either a central power exchange or sizable day ahead and/or real-time markets that are administered by the independent system operator. Two concerns the Commission has expressed with having such reliance on the bilateral market are price discovery and liquidity.[1] A broader market, they note, could provide greater liquidity and price transparency, and provide better information about future supply and demand conditions. The existing market design, they claim, also presents gaming opportunities for market participants that could probably be eliminated by redesigning the market.

ERCOT Market Operations[2]

As noted, ERCOT's wholesale market is a market where participants use bilateral forward contracts almost exclusively, with zonal congestion management and a system operator running a minimal real-time balancing market. The Market Oversight Division of the Texas Public Utility Commission noted that ERCOT is the only operating ISO/RTO-based wholesale market in the U.S. that uses only bilateral forward contracting among market participants. ERCOT's residual energy market for balancing

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[1]Public Utility Commission of Texas, Report to the 78th Texas Legislature, "Scope of Competition in Electric Markets in Texas," January 2003. Much of the details about the Texas markets, unless otherwise indicated, are from this Texas Commission report and from various ERCOT sources.

[2]A useful overview of ERCOT market operations is "The Market Guide: An introductory guide to how the Electric Reliability Council of Texas (ERCOT) facilitates the competitive power market," January 1, 2004.

energy, representing five percent to ten percent of total demand, is for the reliability of the Texas electric grid. The Texas Commission has identified problems with its wholesale market design and has been formally considering changes.

In 2003, the Texas PUC (Order 26376) began a redesign of how the wholesale market manages transmission congestion and provides "day-ahead" market services. A "Nodal Team" of market stakeholders was established in August of 2003 to begin the redesign of the zonal congestion management system to a Local Marginal Pricing (LMP) or "nodal" model. The PUC order is to be implemented by the end of 2006.

Prices in the bilateral market that represents the bulk of delivered energy in Texas are based on mutual agreement or long-term contract between the parties, and are not known by ERCOT. These agreements are incorporated into base energy schedules which are submitted to ERCOT on a daily basis and account for over 90 percent of the end-user electric energy requirements in ERCOT.

Ancillary Services

ERCOT has operated day-ahead ancillary service markets and the real-time balancing energy market since July 31, 2001. ERCOT's five ancillary services (and the total amount required each day) are: Regulation Up (1,200 MW), Regulation Down (1,800 MW), Responsive (spinning) Reserves (2,300 MW), Non-Spinning Reserves (1,250 MW), and Replacement Reserves (as needed). Market participants can self-provide their ancillary service requirements or allow ERCOT to procure these services on their behalf.

During the first year of operation as a single control area, ERCOT usually procured from ten percent to 20 percent of the ancillary service capacity required. Market participants chose to provide their own ancillary services rather than expose themselves to unknown market clearing prices from the ERCOT auction. According to the Commission (in 2003), prices for ancillary services procured by ERCOT were below $20 per MW for more than 95 percent of the time, from August 2001 through July 2002.

Capacity Adequacy

ERCOT currently has no formal capacity market comparable to PJM's capacity credit market. The Texas Commission is developing a generation adequacy rule which likely will use a mechanism that differs from capacity credit markets in the northeast region of the U.S. ERCOT utilities have traditionally sought to maintain a planning reserve margin of 15 percent. Because the system cannot rely on imports, due to its isolation from surrounding interconnections, relatively high reserve margins are thought necessary. However, in mid-2002, the ERCOT Board approved a 12.5 percent reserve margin requirement.

In 2000 and 2001, the reserve margins at peak were 14 percent and 21 percent, respectively. From 1995 to January 2001, 22 new generating plants, totaling more than 7,600 MW, were built in the ERCOT region. This represents 10.9 percent of total generating capacity; during this same period, peak demand grew by 24.5 percent. The Texas Commission reports[3] that statewide (ERCOT and non-ERCOT regions of the state) 68 plants for a total of 29,375 MW were completed from 1995 through early 2004. Also, it was reported that 6 plants with a total of 2,483 MW were under construction, 14 plants with a total of 7,108 MW had been announced or planned, and 15 plants totaling 8,212 MW had been delayed. The Commission indicated that 7,349 MW of announced new generation capacity had been cancelled, 7,296 MW had been "mothballed," and 1,211 MW were retired. Of the completed capacity additions, wind turbines accounted for 1,260.5 MW of the projects, while the remaining 28,114.5 MW were nearly all natural gas combined cycle plants. The Texas Commission is reporting an expected ERCOT capacity reserve margin of 27.1 percent for 2004 and a 23.8 percent expected reserve margin for 2005.[4] By 2008, the current expectation is for it to decline to 17.3 percent.

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[3]These data on generating plant project status are from "New Electric Generating Plants in Texas Since 1995," April 15, 2004.

[4]Public Utility Commission of Texas, presentation before Senate Business and Commerce Committee, "State of the State –A Brief Review of Electric Competition," April 27, 2004.

The Commission noted that transmission constraints limit the deliverability of some generation resources, especially wind power from West Texas. The Commission states that so much wind power has been added that the existing transmission system is not always capable of delivering all of the power available from the wind projects. Transmission projects are planned to relieve the bottlenecks, but they report that significant new facilities are required, which will take up to five years to complete.

ERCOT introduced monthly and annual Transmission Congestion Rights (TCRs) auction markets in February of 2002. TCRs were implemented in ERCOT along with the implementation of direct assignment of interzonal congestion charges to allow market participants a means to offset the risk of transmission congestion charges. ERCOT initially adopted a simple flow-based transmission right approach and flow-based congestion charges. An annual auction is held for 60 percent of the TCRs, the remaining 40 percent are auctioned on a monthly basis.

Real-Time Balancing Energy Market

As noted, ERCOT does not have a central power exchange or sizable day ahead or real-time energy markets administered by an independent system operator. However, ERCOT does have a balancing energy market designed to maintain the balance between load and generation and to resolve transmission congestion. Balancing energy makes up the difference between the total ERCOT electricity requirements and the sum of the base energy schedules. The real-time balancing energy market process accepts bids in ascending order of price until the total quantity required is obtained. The bid price of the last quantity accepted for Balancing Energy Service sets the Market Clearing Price of Energy (MCPE) for that 15-minute interval.

The balancing energy market is not a spot market, but an ancillary service market, and accounts for only five to ten percent of the total ERCOT energy market.

Market Prices

Figure VII.1 shows the ERCOT energy spot market prices for the five trading zones, as reported in *Megawatt Daily*. These are volume-weighted average daily price

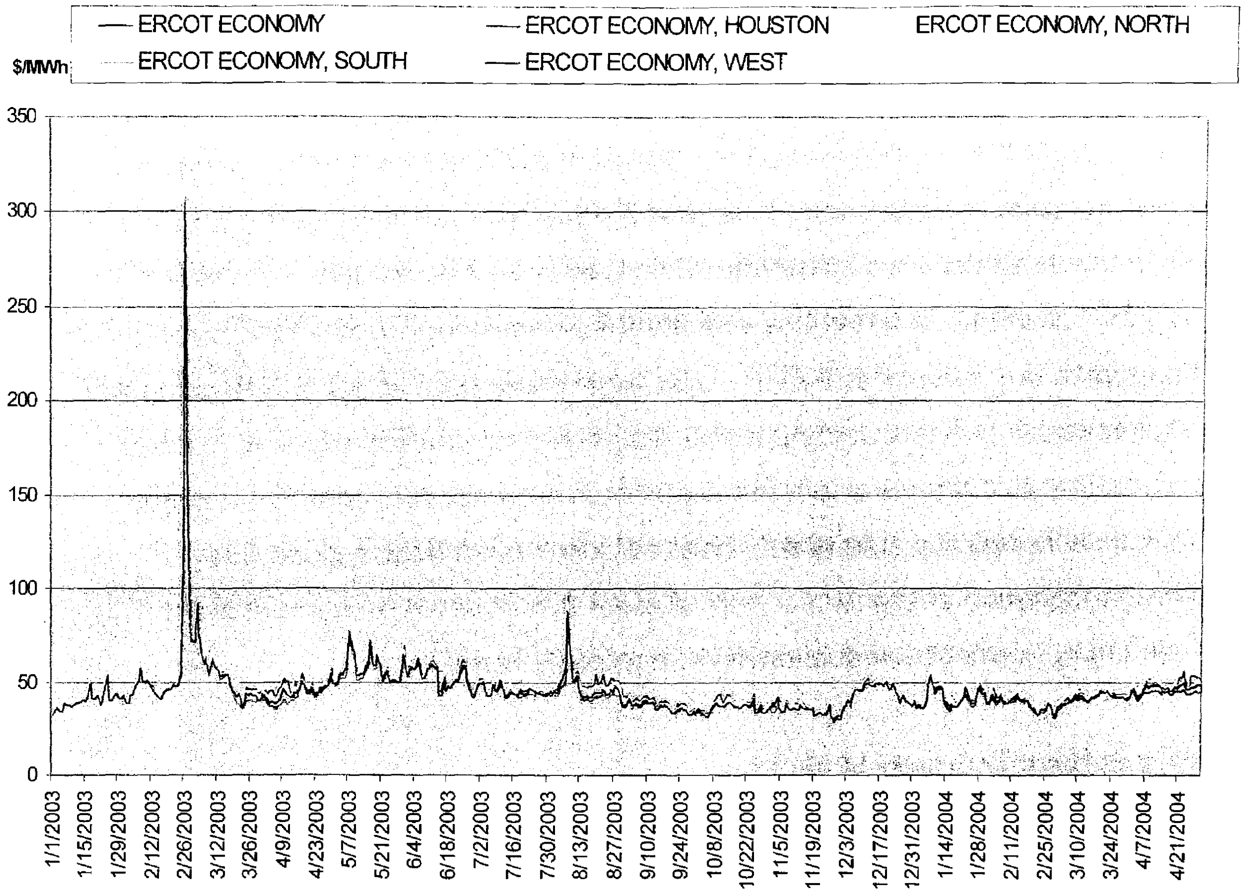

Figure VII.1. Daily volume weighted average price indices ($/MWh) for ERCOT trading zones.
Data source: Platts, *Megawatt Daily*, January 2003 through April 2004.

indices for the trading zones. Being an interconnected region, the ERCOT zone prices move together in a relatively tight range. There was a considerable price spike that occurred in early 2003, when prices reached $300 per MWh or more in four of the zones (the peak was $325 per MWh for the Houston zone). Another spike occurred in the summer of 2003 to nearly $100 per MWh. Prices traded mostly in the $40 to $50 per MWh range or higher for most of March and April of 2004.

Texas Retail Market

Overview

As noted, Texas passed their restructuring bill in June of 1999 and retail competition began for all customers of investor-owned utilities in the Electric Reliability Council of Texas (ERCOT) region on January 1, 2002. For areas served by municipal utilities and electric cooperatives, competition is allowed if the governing body of the city or cooperative opts for retail competition. Metering services for commercial and industrial customers opened to competition beginning January 1, 2004. For residential customers, metering services are regulated until September 1, 2004 or until 40 percent of customers have switched to an alternative supplier, whichever is later.

The Legislature delayed retail competition for utilities in the non-ERCOT regions of Texas, in the El Paso Electric service area until September 2005, (the end of the rate-freeze period from El Paso Electric's bankruptcy proceeding in 1995) and in the Southwestern Public Service Company service area (in the Panhandle region of Texas) until 2007 at the earliest. The Southwestern Public Service Company service area is described as a transmission-constrained area that has limited access for alternative power generation companies and retail providers to serve customers.[5] The Public Utility Commission of Texas delayed the start of full customer choice for the Entergy, Southwestern Electric Power Company (SWEPCO – the Commission suspended full customer choice until January 2007 for SWEPCO), and a small portion of West Texas Utilities Co.'s (WTU)[6] service area that is located within the Southwest Power Pool region. The Commission delayed competition for the Entergy and SWEPCO service areas because of three concerns: (1) a lack of independence in the administration of transmission service and uncertainty about the market rules for these areas; (2) a lack

[5]The Legislature required Southwestern Public Service Company to conduct an analysis on the need for additional transmission infrastructure and on plans to interconnect with other power regions.

[6]WTU is now also known as AEP Texas North, an affiliate Retail Electric Provider (REP) of AEP's Texas local distribution utilities. AEP Texas Central, also is still known by its former names CPL, Central Power and Light Company, or CPL Retail Energy.

of testing of the technical systems needed to accommodate retail choice; and (3) a lack of necessary market institutions and lack of open and non-discriminatory access to the transmission grid.

Investor-owned utilities were required to separate their business functions into three distinct companies: a power generation company (PGC), a transmission and distribution utility (TDU), and a retail electric provider (REP). PGCs operate as wholesale providers of generation services, such as independent power generators. REPs operate as retail providers of electricity and energy services and have primary contact with retail customers. TDUs remain regulated by the Commission, and are required to provide non-discriminatory access to the transmission and distribution grid at rates and terms of access prescribed by the Commission.

The "Price-to-Beat"

Customers who did not choose a new retail electric provider, or REP, by January 1, 2002 were automatically transferred to their utility's affiliated REP. Residential and small non-residential electric customers (with a peak demand of 1 MW or less) who remain with the affiliated REP are charged a regulated rate, called the "price-to-beat." Commission rule generally required a 6% reduction from the rates in effect on January 1, 1999 for residential and small commercial customers, with adjustments for the setting of a final fuel factor for the integrated utility as of December 31, 2001. The reduction applied to customers who did not choose a REP and continue to take service from the affiliated retail electric provider. The affiliated REPs are required to sell electricity at the price-to-beat until January 1, 2007.

Texas purposefully set the price-to-beat with some "headroom," that is, to allow the difference between the price-to-beat and the costs incurred by non-affiliated REPs (see the discussion in the overview section of this report) to be sufficient to allow competitors to profitably offer prices to customers for their services and offer sufficient savings off the price-to-beat so that customers are encouraged, by the potential savings, to consider alternative suppliers. The Commission found, as other states have, that if the price-to-beat or the fuel factors were not adjusted to reflect changes in the market price of electricity, the price-to-beat could fall below the costs of alternative REPs and competition in the retail market will not develop and decline (negative headroom). For this reason, the price-to-beat is adjusted to reflect changes in natural gas and purchased energy market prices. If the price of natural gas futures changes by more than four percent, Commission rule permits the affiliated REP to request adjustments to their fuel factor. Also, if headroom diminishes from changes in the market price of purchased power as measured by one-year and three-year contract prices, the affiliated REP may also request an adjustment to the price-to-beat.

Affiliated REPs, that is, the incumbent utility, can offer rates lower than the price-to-beat beginning January 1, 2005, or earlier if at least 40 percent of residential or small-commercial customers switch to competitors.

The price-to-beat rates for residential customers for each affiliated REP are shown in Table VII.1. In the case of First Choice/TNMP, CPL/Mutual Energy, and WTU/Mutual Energy, base rates changed a level other than six percent due to changes in rates between January 1, 1999 and December 31, 2001 that resulted from merger proceedings. (See the sideline note on company names in Texas.) Since retail access began on January 1, 2002, the Price-to-Beat has increased significantly for all the companies – by 22 percent, 28 percent, 23 percent, 30 percent, and 34 percent for TXU, Reliant/CenterPoint, First Choice/TNMP, CPL/Mutual Energy, and WTU/Mutual Energy, respectively.

Table VII.1. Price-to-Beat rate comparison (cents per kWh).*

Affiliated REP	Dec. 31, 2001	Jan. 1, 2002	Sept. 2002	June 2003	May 2004
TXU	9.67	8.25	8.66	9.70	10.06
Reliant/CenterPoint	10.40	8.62	9.12	10.10	11.05
First Choice/TNMP	10.57	8.66	9.15	10.10	10.65
CPL/Mutual Energy	9.57	8.80	9.52	10.92	11.42
WTU/Mutual Energy	9.98	8.88	9.73	11.34	11.91

*May 2004 Price-to-Beat for 1,000 kWh.
Source: Public Utility Commission of Texas, January 2003 and May 2004, ENERGYguide.com, June 2003.

The Commission reports that because of significant increases in the price of natural gas, the fuel factor portions of the rates have been rising significantly and also required fuel surcharges to recover past uncollected fuel expenses. At the end of 2001, natural gas prices had fallen significantly, resulting in reductions in the fuel factor portion of the price-to-beat rates. Also, the fuel surcharges that were in place during 2001 terminated in December 2001. As a result, customers received in excess of a six percent reduction in their total rates as compared to rates in effect on December 31, 2001. Natural gas prices dropped in the early months of 2002, but began to rise significantly in March and April of 2002. All of the affiliated REPs (except TXU-SESCO) subsequently requested adjustments to their price-to-beat fuel factors in order to reflect increases in the price of natural gas in the range of 16 percent to 24 percent. Reliant Resources filed for a second adjustment in November 2002 to reflect a further seven percent increase in natural gas prices (that was approved by the Commission in December 2002).

> Due to mergers; the required unbundling of investor-owned utilities into three companies – (1) power generation company (PGC), (2) transmission and distribution utility (TDU), and (3) retail electric provider (REP); and other structural changes that companies in Texas have undergone in recent years, the names of companies have been changed or new names created. In this report, where possible, the names of the companies reported by the Commission along with the figures supplied are used in the tables and graphs. In the text, the company's pre-retail access utility name is also given. Here is a summary of the utility, REP, or new names that are used:
>
> - Central Power and Light Co. / CPL / AEP Texas Central / now CPL or Mutual Energy
> - HL&P / Reliant Energy / CenterPoint Energy
> - Texas-New Mexico Power Co. / TNMP / First Choice Power
> - TXU Electric & Gas / Oncor
> - West Texas Utilities Co. / WTU / AEP Texas North / now WTU or Mutual Energy.

Provider of Last Resort (POLR) Service

In areas of the state where retail access is in effect, the Commission designates REPs to serve as providers of last resort or a POLR. The Commission adopted POLR rules in October 2000 that required the selected POLR to charge a fixed rate that could not be changed over the term of the POLR contract. Each POLR was required to offer a standard retail service package for each class of customers designated by the Commission at the approved fixed, non-discountable rate. In the event that a REP failed to serve its customers, the POLR must offer the standard service package to those customers with no interruption of service. The standard service package must also have been available to any requesting customer. In addition, under the original POLR rule and customer protection rules, only the POLR had the authority to disconnect customers for nonpayment of electric services. Other REPs could only cancel a nonpaying customer's contract and transfer that customer to the POLR.

POLRs were originally to serve two types of customers: (1) customers of a REP that chose to exit the market without making arrangements to transfer those customers to another REP, and (2) non-paying customers of a REP. For the first set of customers, POLRs faced the risk of potentially being required to serve a large number of customers from an exiting REP with little notice and at a fixed rate that was set far in advance of the switch. For the second set of customers, POLRs faced the risk of serving customers that had already demonstrated an inability or unwillingness to pay their provider for energy consumed. The Commission states that the combination of these risks led to the high rates initially set for the POLRs for 2002. Several parties appealed the orders and contracts with the POLRs alleging that the rates were not just and reasonable, and that the Commission erred in the process it used to select POLRs and set the rates for POLR service.

The Commission's new POLR rules remove non-paying customers from the class of customers served by the POLR. REPs no longer transfer non-paying residential and small commercial customers to the POLR, as of September 2002. Instead non-affiliated REPs transfer them to the affiliated REP for service at the price-to-beat. The affiliated REP has authority to disconnect the customers if the customer does not establish any required deposit with the affiliated REP, or subsequently does not pay a bill of the affiliated REP. All REPs have authority to disconnect large commercial and industrial customers for non-payment, unless an existing contract provides for different treatment.

This structure will remain in place until October 1, 2004. After that, all REPs will have the authority to disconnect non-paying customers, if protections are in place for retail customers. The primary purpose of the POLR service is now to serve customers of a REP that exited the market without making arrangements to transfer their customers to another REP.

The original POLR rules chose a sealed-bid competitive bidding process to set the POLR rates. The Commission conducted a bid for each customer class in each designated service area, but only one REP submitted a bid. The Commission accepted the bids of TXU Energy Services to provide POLR service in the majority of the state. The Commission designated non-bidding REPs to serve as POLRs and set the rates for the remaining areas of the state where no bid was received through negotiation and in contested case proceedings. The initial rates for POLR service, whether approved by bid, negotiation, or contested case proceeding, were substantially above the price-to-beat in all areas.

Under the revised POLR rules, the Commission compares bids for POLR service on price alone and the selected rates are to be adjusted monthly to reflect changes in wholesale market prices. If no bids are submitted or all bids are rejected, the new rule requires the Commission to select POLRs by a lottery. The selected POLRs would provide service at specific rate levels determined under the rule. For service beginning January 1, 2003, only affiliated REPs were eligible to bid or be selected by lottery. Bids could also not exceed 125% of the price-to-beat for residential and small commercial customers.

The Commission noted that the competitive process it envisioned has yet to perform adequately. Only Reliant Resources submitted a POLR bid under the new process and was selected as POLR for most areas of the state. TXU Energy Services, First Choice Power, and AEP did not submit bids under the revised rule. The Commission held a lottery for the areas where Reliant did not bid.

The 2002 and 2003 POLR rates for Texas service areas are in Table VII.2.

Table VII.2. POLR rates for 2002 and 2003 (cents per kWh).

Service Area	2002 POLR Rates	2003 POLR Rates
Reliant/CenterPoint	11.96	10.83
TXU/Oncor	10.54 - 11.05	10.00
WTU/AEP Texas North	12.86	12.37
CPL/AEP Texas Central	12.22	11.08
TNMP/First Choice Power	12.13	10.99

Source: Public Utility Commission of Texas, January 2003, p. 44.

Customer Choices

Texas continues to have the most active market in the country for residential customers in terms of offers and savings opportunities. In May 2004, as summarized in Table VII.3, residential customers had between six to ten competitive providers offering between eight to 14 competitive offers (this count does not include the affiliated REP's standard service at the price-to-beat rate). All five areas have at least seven offers below the price-to-beat rate, two areas had seven offers, and three areas had eight offers below the price-to-beat. As measured by the lowest offer, residential customers had an opportunity to save between ten percent and 22 percent off the price-to-beat rate.

According to the Texas Commission, reporting in early 2003, commercial and industrial customers also appear to have a large variety of offers from which to choose. They report that there were, as of September 2002, approximately 19 REPs serving commercial and industrial customers in all service territories open to competition. As seen in other states, while residential offers are sometimes publicly available, the commercial and industrial market operates mostly under individual contracts. These customers often negotiate the type of service (firm vs. interruptible, short term vs. long term), and choose the amount of risk of price volatility (fixed price vs. indexed) they desire to accept. Customers who have negotiated contracts with the pricing tied to natural gas or power market prices enjoyed extremely low prices early in 2002 when natural gas prices (and power prices) dropped dramatically. Customers who have negotiated fixed price contracts have been able to avoid the subsequent increase in prices that have occurred since.

Table VII.3. Residential competitive offer summary for Texas, May 2004

Utility	Number of Competitive Suppliers	Total Number of Offers from Competitive Suppliers	Number of Offers Below the Price-to-Beat	Savings with Best Offer*
TXU/Oncor	10	14	8	17%
CPL/Mutual Energy	8	12	8	20%
WTU/Mutual Energy	6	8	8	22%
Reliant/ CenterPoint	10	12	7	17%
TNMP/ First Choice Power	7	11	7	10%

*Calculated by comparing the Price-to-beat with the lowest offer in cents/kWh.
Data Source: Public Utility Commission of Texas, based of offers from ENERGYguide.com.

Figure VII.2 graphs all the residential offers in five service territories that were made in late May 2004 (the same offers tallied in Table VII.3). All service areas had offers below the price-to-beat (heavy dashed line in figure) and also at or greater than ten percent savings (dotted line in figure).

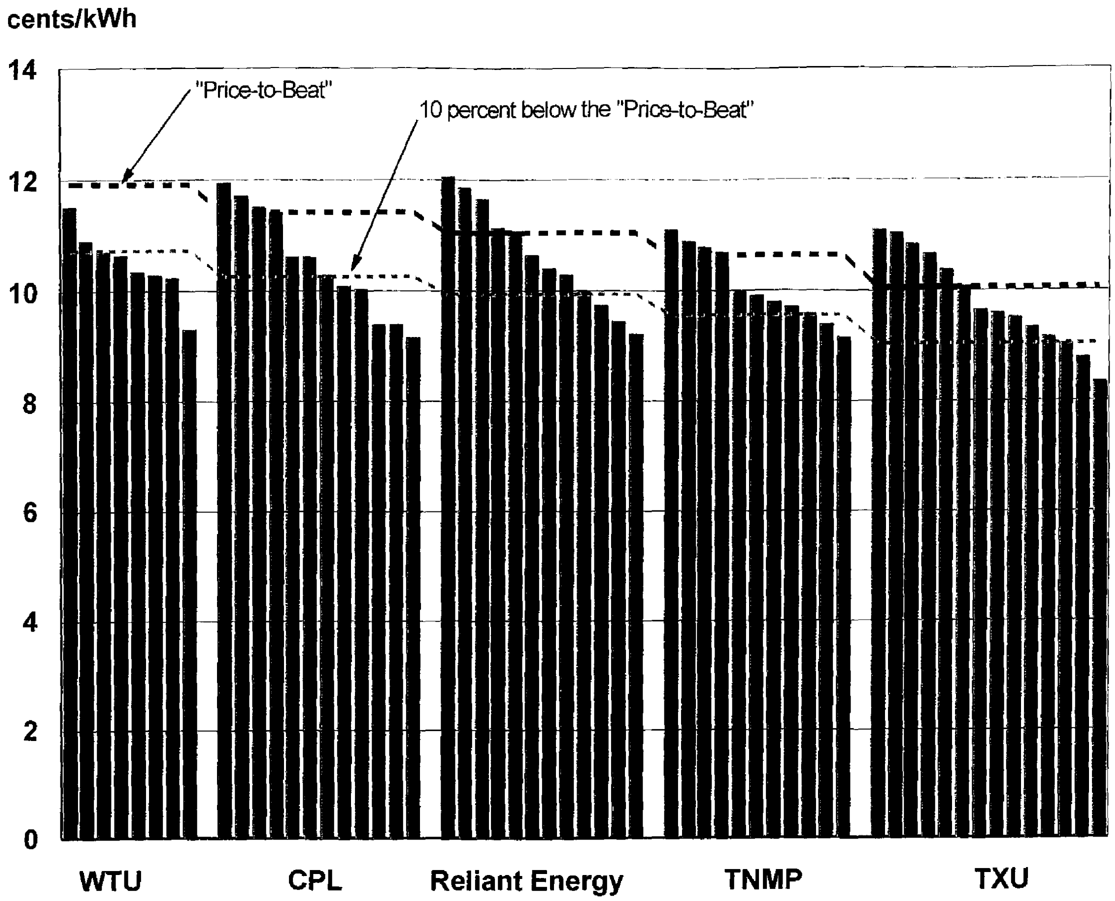

Figure VII.2. Residential offers in five Texas service territories, May 2004. Data Source: Public Utility Commission of Texas, based of offers from ENERGYguide.com.

<u>Customer Switching</u>

As Figure VII.3 shows, almost 15 percent of all residential customers were served by a non-affiliated REP by December 2003. All service areas had over ten percent of residential customers being served by non-affiliated REPs by the fall of 2003. WTU reached almost 20 percent by the end of 2003. Figure VII.4 shows that about 28 percent of CPL secondary voltage customers

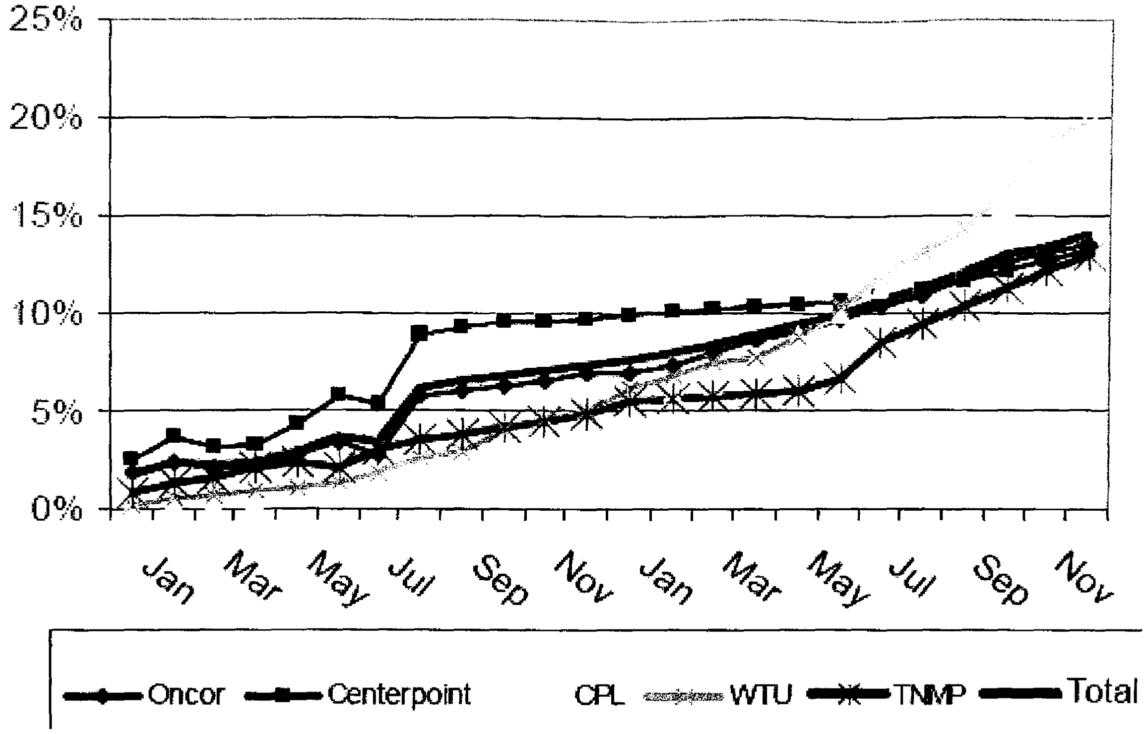

Figure VII.3. Residential customers with competitive REP.
Source: Public Utility Commission of Texas, March 2004 Report Card on Retail Competition.

(primarily smaller commercial and industrial customers, most of which are eligible for the price-to-beat) were receiving power from competitive REPs by December 2003. CPL had the highest percentage of these customer, while about 19 percent of all the secondary voltage customers were with a competitive REP by December 2003. Figure VII.5 shows that over 40 percent of the secondary voltage load (MWh) were with competitive REPs. CPL, again with the highest percentage, at over 60 percent the customer load.

About 35 percent of commercial and industrial customers that receive service at primary or transmission voltage levels (larger commercial and industrial customers, many of which are not-eligible for the price-to-beat) were receiving service from a non-affiliated REP in December 2003 (Figure VII.6). (The Commission does not report a break down by TDU area because of concern for confidentiality of market share information for these customers by

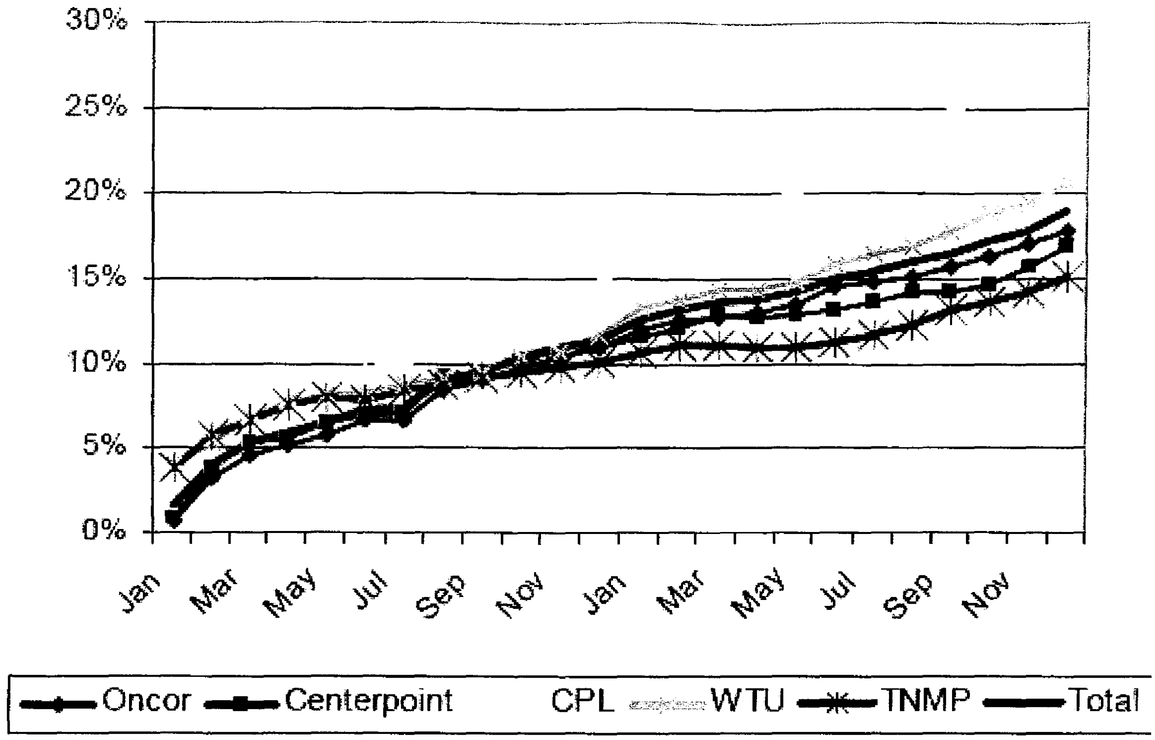

Figure VII.4. Secondary voltage customers with competitive REP.
Source: Public Utility Commission of Texas, March 2004 Report Card on Retail Competition.

the affiliated REPs. They note that the trends are similar across TDU areas with respect to the number of customers that are being served by non-affiliated REPs.)

Customers without a price-to-beat available from the affiliated REP, are essentially in the market and were encouraged to choose to purchase power from the affiliated REP or a competitive REP. As seen nationally, because these customers use large amounts of power and have a strong incentive to consider alternatives, they are usually the most active shopping group and are usually the more sought after customers by retail suppliers. In addition, the Texas Commission required affiliated REPs to give the non-price-to-beat customers advance notice of the rate they would be charged on January 1, 2002, if they did not negotiate other arrangements with the affiliated REP or

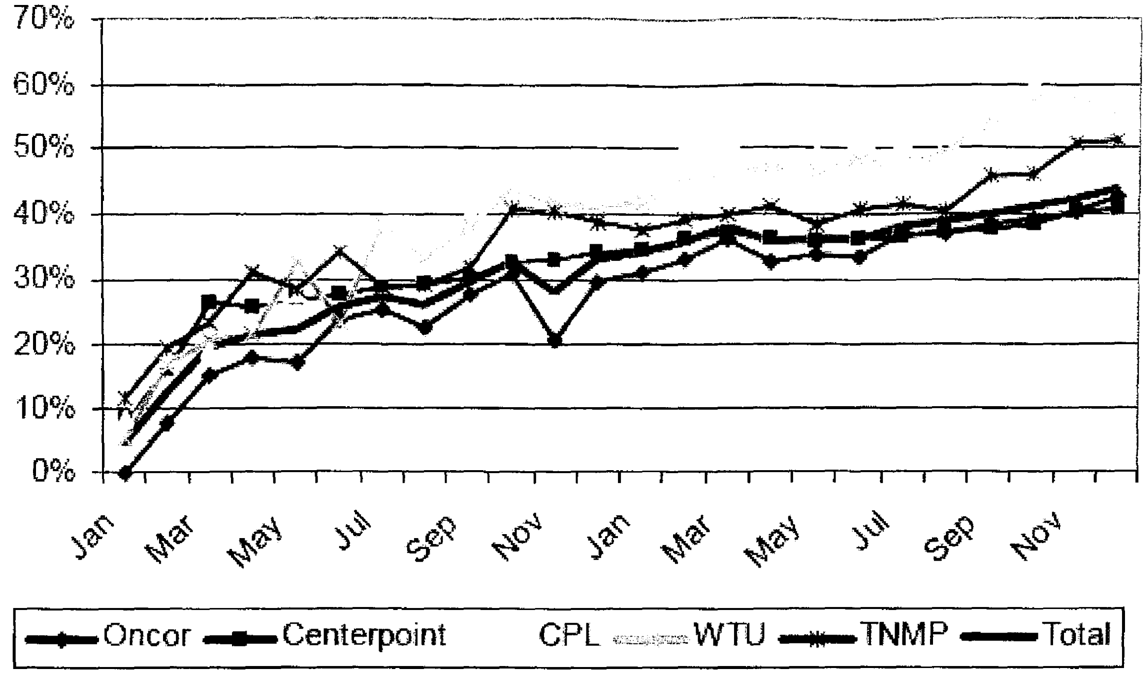

Figure VII.5. Secondary voltage megawatt-hours with competitive REP. Source: Public Utility Commission of Texas, March 2004 Report Card on Retail Competition.

switch to a competitive REP. The Commission reports that the default offers of the affiliated REP were generally either a very high fixed price offer or a pass-through of market prices, both of which may be considered risky options for most retail customers. This likely provided added incentive for these customers to shop for the best available price, since the default offers may lead to rates higher than those in effect before retail access began. No percentage numbers were released by the Commission for these customers since early 2003, however, as of December 2002, approximately eight percent of the non-price-to-beat customers remained on this default pricing offer, or approximately 92 percent of these customers have negotiated a competitive contract with either the affiliated REP or a non-affiliated REP.

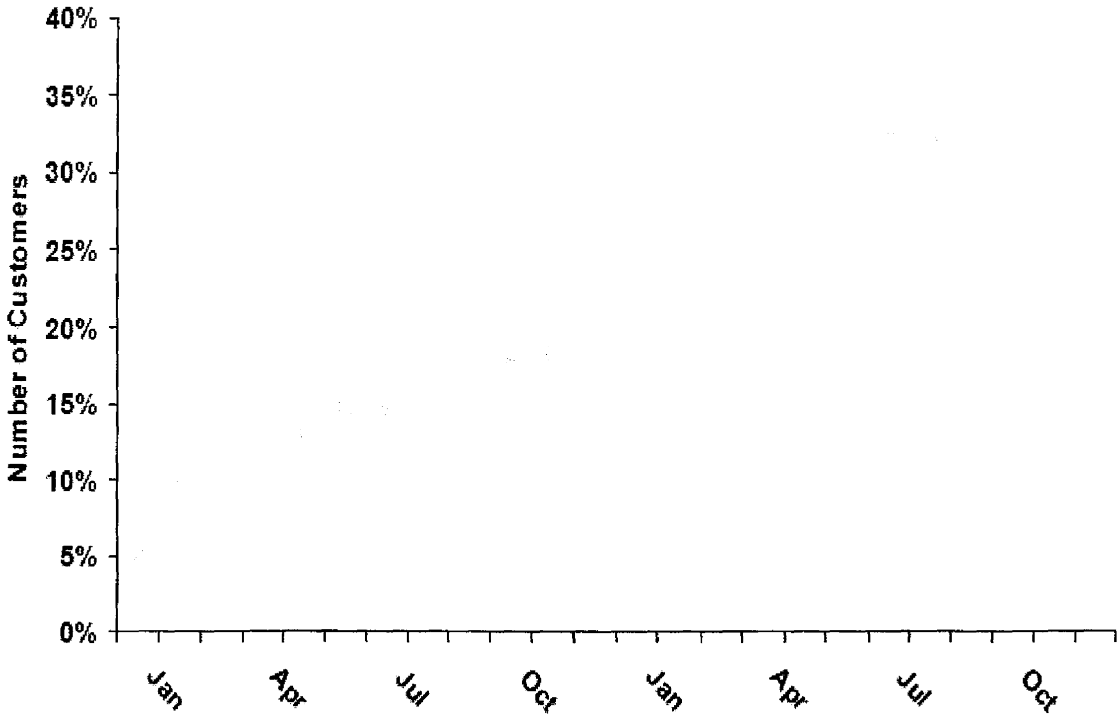

Figure VII.6. Primary or transmission voltage customers served by non-affiliated REPs.
Source: Public Utility Commission of Texas, "State of the State –A Brief Review of Electric Competition," April 27, 2004.

Stranded Cost True-Up

Utilities are required to finalize their stranded cost determination in 2004 through a market valuation of assets. The Commission is concerned that because of the current level of uncertainty and the lack of investor interest in wholesale generation companies, the market-based valuations of generation facilities or companies that own them may result in significant stranded costs for several companies. High stranded costs would, in turn, likely result in higher delivery charges from the TDUs. In Texas (as in many other states), the

Commission noted that stranded costs are predominately related to nuclear generation assets' high capital costs.

The initial estimates of stranded costs were made during the cost separation cases filed by the utilities in April 2000. In large part due to high estimates of natural gas prices, the Commission found initial estimates of stranded costs to be negative, that is, estimates of the market value of the generation resources exceeded the net book value of the assets. As a result, the Commission did not establish interim CTCs and instead ordered the utilities to begin returning stranded cost mitigation to customers as a credit to the non-bypassable charges (the "excess mitigation credit," or EMC).

In December 2001, the Commission adopted a rule to establish the procedures by which formerly integrated utilities will conduct their true-up proceedings in 2004. The primary purpose of the true-up proceedings is to reach a final determination of the utilities' stranded costs as the new rule establishes the process for quantifying the stranded costs of the utilities, and the reconciliation of that amount with prior estimates is used to set rates. Several investor-owned utilities have appealed the true-up rule.

TXU and Entergy have both agreed to forego further stranded cost recovery, and will not be conducting true-up proceedings as a result of these settlements. Reliant/Centerpoint, TNMP, and CPL/AEP are required, barring additional settlements, to finalize their stranded costs. In early 2004, the Commission reported[7] that Reliant/CenterPoint had stranded costs of $2.4 billion, requested true-up of $1.4 billion and other adjustments of $0.6 billion, for a total of $4.4 billion. TNMP had stranded cost of $307 million, requested true-up of $107 million, less other adjustments of $57 million, for a total $357 million. Estimate for CPL/AEP were $1 billion in stranded costs and true-up of $0.5 billion.

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[7]Public Utility Commission of Texas, presentation before Senate Business and Commerce Committee, "State of the State –A Brief Review of Electric Competition," April 27, 2004.

The rule amendments included a "transmission cost recovery factor," or TCRF, that permits a utility to receive expedited cost recovery of additional transmission investments, and include those costs in the non-bypassable rates that are charged to retail customers. The TCRF is to only recover the capital costs associated with new investments in transmission facilities, and is subject to reconciliation in the transmission utility's next transmission rate case. The Commission believes that the TCRF mechanism will encourage the timely construction of new transmission facilities needed to facilitate competition by reducing the risk to the transmission utility of making such investments. (This is similar to a FERC proposal issued in January of 2003.)

SECTION VIII
West

Wholesale Markets in the West

Currently, there is one functioning ISO in the west, the California ISO. The California ISO began operation on March 31, 1998 and is a not-for-profit public benefit corporation that operates California's wholesale power grid. The ISO covers most of the state, with members that include the three major distribution companies in the state, Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company. The ISO's principal function is to maintain reliability in its operation of the power grid that serves 30 million people in the state. The ISO has 25,526 circuit miles of transmission lines that it manages and supervises the maintenance on, but the transmission systems are owned and maintained by individual utilities. The ISO also acts as a transmission planner, identifying and approving enhancements transmission owners make to the grid to meet high reliability standards.

The ISO coordinates about 40,000 arrangements for electricity every hour between buyers and sellers, tracking prices and the settlement system, but does not buy or sell power itself. The ISO operates three markets to allocate transmission capacity, maintain operating reserves, and match supply with demand. However, these markets together make up less than ten percent of the total wholesale electricity market. The three markets the ISO operates are:[1]

> (1) Ancillary Services Market – for adjusting the flow of electricity for unexpected events, such as a power plant failure or a sharp rise in demand for power. The capacity that is bought and sold can be dispatched within seconds, minutes or hours. The Ancillary Services Auction is conducted for day-ahead and hour-ahead of when the electricity is used for:

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[1]This information is from the California ISO, at http://www.caiso.com.

Regulation — generation that is already running (synchronized with the power grid) and that can be increased or decreased instantly to keep energy supply and energy use in balance;

Spinning Reserves — generation that is running, with additional capacity that can be dispatched within minutes;

Non-Spinning Reserves — generation that is not running, but can be brought up to speed within ten minutes; and

Replacement Reserves — generation that can begin contributing to the grid within an hour.

(2) Transmission Market – to allocate space on the transmission lines for the day-ahead and the hour ahead of when electricity is delivered. When there is transmission congestion, Scheduling Coordinators operating in congestion zones can participate in the congestion management market, curtailing their power deliveries or generating more.

(3) Real-Time Imbalance Market – for supplemental energy that can be quickly bought or sold every 10 minutes to accommodate energy use moments before it occurs. Scheduling Coordinators receive payment for extra generation they supply or are billed for extra energy they need to meet customer demand. Market Participants can submit incremental bids to supply more power, or decremental bids to reduce power output because of oversupply or congestion on transmission lines.

These markets are monitored by the ISO's Department of Market Analysis, that watch wholesale prices and look for any market power abuse. The ISO's Compliance Department ensures that market participants meet their obligations by monitoring responses to dispatch instructions and imposing penalties for non-compliance.

There are two other transmission organizations that are developing in the west. RTO West members filed a plan with FERC in October 2000 to form an RTO. FERC conditionally approved parts of the RTO West proposal as a "first step" in April 2001. The RTO would operate (but not own) transmission systems for participating transmission owners in California, Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming. This would be a non-profit independent operator. In March 2004, members of RTO West decided to change the name to "Grid West." In the southwest, WestConnect (formerly DesertSTAR) members announced they would develop a for-profit RTO in October 2001 and received FERC's conditional approval. This area includes Arizona, Colorado, New Mexico, and parts of Texas and Wyoming. A grid-wide tariff for WestConnect may not be in place until 2009 and an operational RTO until 2011. The geographic areas of all three western transmission organizations are shown in Figure I.4 in Section I.

FERC had indicated at one time that they preferred a single western RTO. However, plans have been proceeding with the thee transmission organizations as just described. All three of these transmission organizations in the west, California ISO, Grid West, and WestConnect, are working with the Seams Steering Group - Western Interconnection (SSG-WI), created in 2002, to discuss and deal with "seams issues" to coordinate the three organizations and perhaps create a "seamless" western market in the future.

Figure VIII.1 graphs *Megawatt Daily*'s volume weighted-average (peak hour) price indices for six wholesale hubs in the western region.[2] Mid Columbia, in the northwest, is primarily hydro-based and generally the lowest cost. The other price indices move together in a relatively tight range given the wide geographic area they cover. As with other power markets, the natural gas price spike in early 2003 caused all the price indices to move higher nearly in unison.

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[2]Platts describes the hubs as follows: California-Oregon Border: deliveries at the Captain Jack and Malin substations in southern Oregon. Four Corners: deliveries at the Four Corners, Shiprock and San Juan substations in northwestern New Mexico. Mid Columbia: deliveries at ties to a number of dams on the Columbia River, namely Midway, Rocky Reach, Wells and Wampum/Vantage. Power at the John Day dam is priced separately and not part of this index. NP 15: deliveries north of Path 15 in California on selected ties between Los Banos and Gates. Palo Verde: deliveries at the Palo Verde switchyard in southeastern Arizona. SP 15: deliveries south of Path 15 in California on selected ties between Gates and Midway.

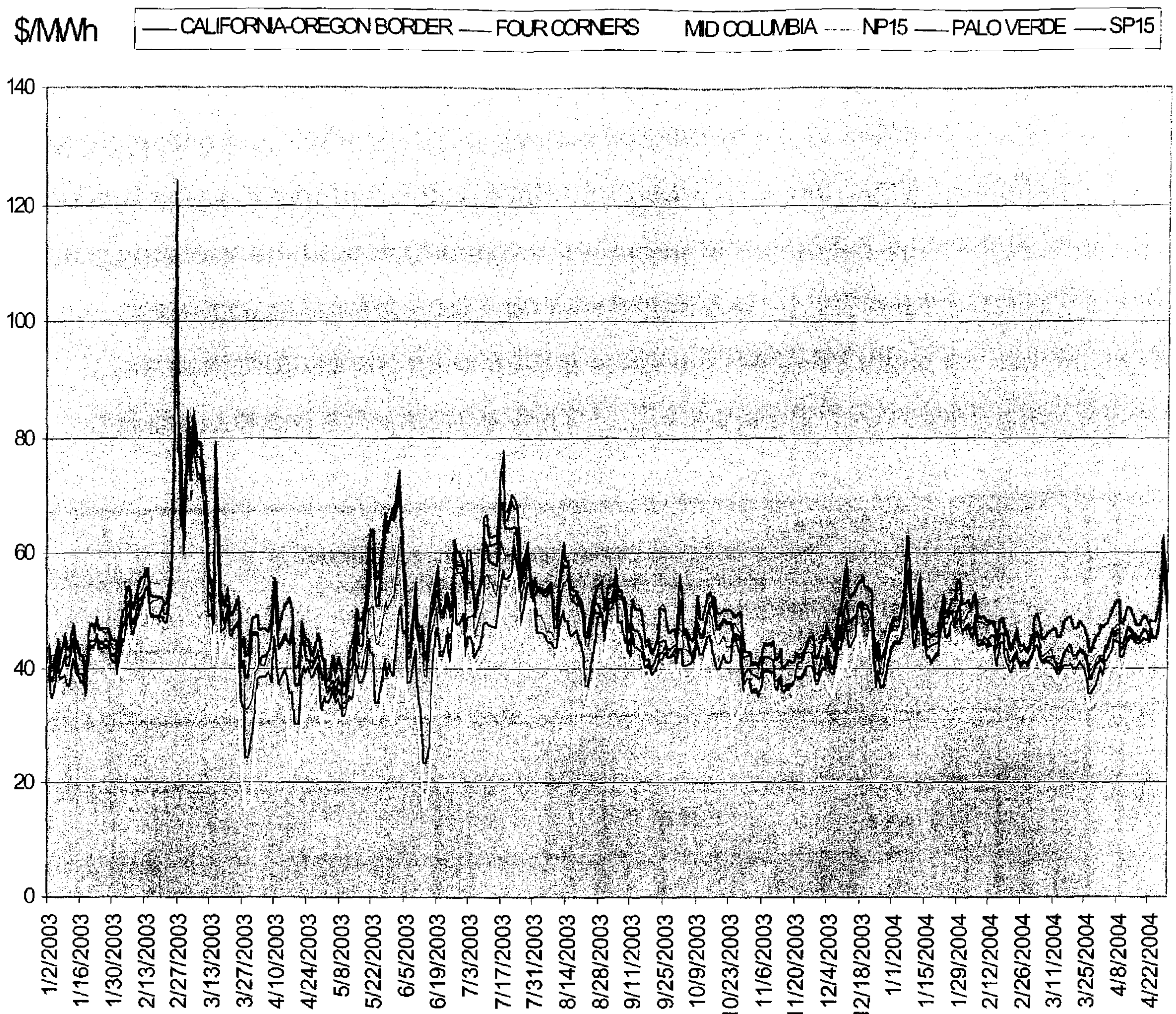

Figure VIII.1. Daily weighted-average wholesale power prices in the western region. Data Source: Platts, *Megawatt Daily*.

Wholesale Market Performance

Previous Performance Reviews summarized several analyses of the California and western power crisis that occurred from late May 2000 through July 2001. These analyses have been conducted by the California ISO's internal market monitor, the Department of Market Analysis, the Market Surveillance Committee members, and others. Because of the power crisis, California's market is perhaps the most studied and evaluated market in the country, for the crisis period. For more recent analyses, only the California ISO of the three transmission organizations in the West conducts on-going analysis of its markets.

As an update of previous Performance Reviews, Figure VIII.2 is a graph created by the California ISO's Department of Market Analysis of the monthly average market clearing prices and their estimated markups for the real-time incremental energy market for January 2003 to June 2004. The actual real-time incremental energy price is generally higher, as might be expected since it is for short-term sales, than the wholesale index prices seen in Figure VIII.1. They calculate the markup using two

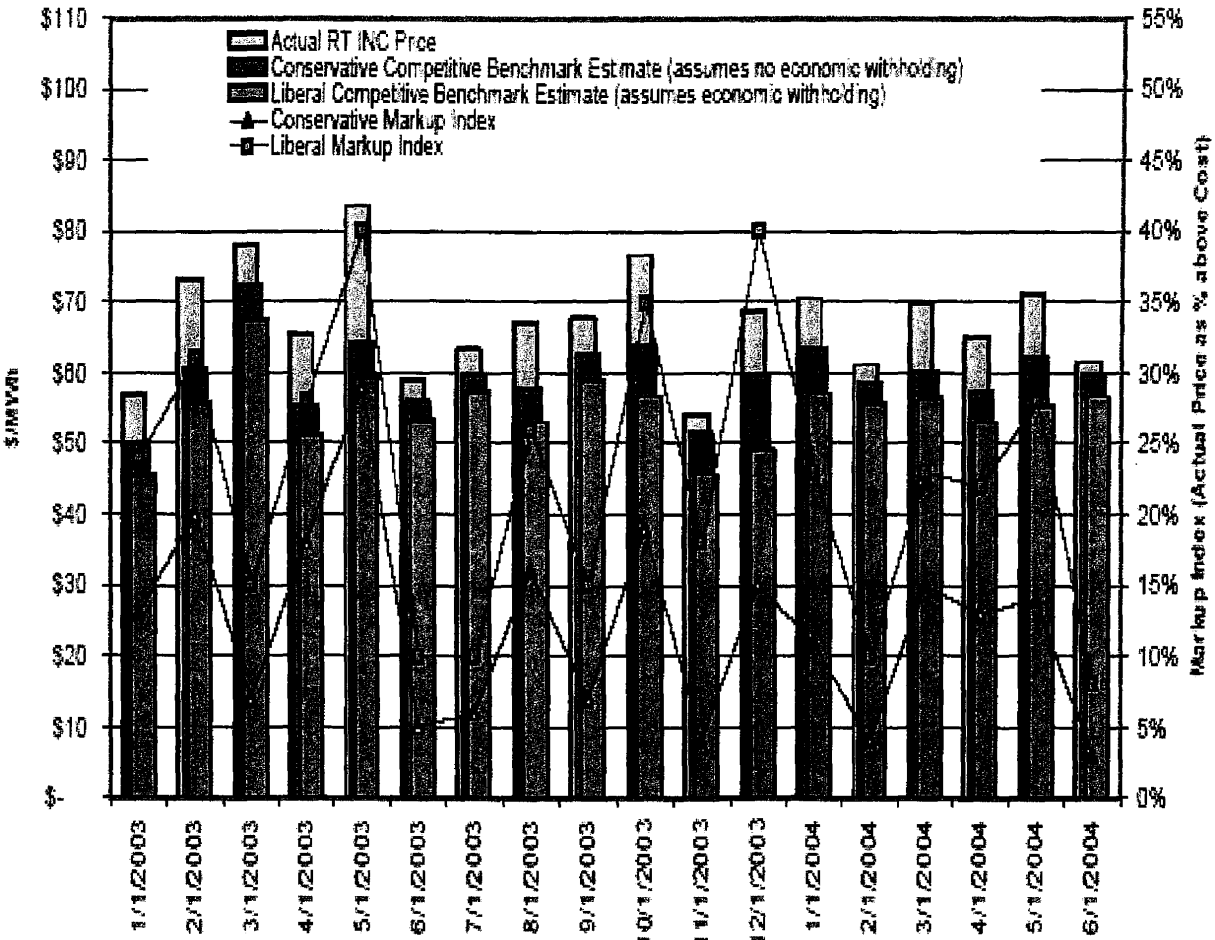

Figure VIII.2. Monthly average competitive market clearing prices and markups in real-time incremental energy market, January 2003 to June 2004.
Source: Greg Cook, "Market Update," Market Surveillance Committee Meeting, California ISO Department of Market Analysis, July 16, 2004.

different methods to calculate the competitive benchmark estimate, which is an estimate of the price that would occur under competitive conditions for comparison with the actual price.[3] The markup is then calculated as the percent of the actual price that is above the benchmark estimated price. The "conservative" benchmark assumes no economic withholding, while the "liberal" benchmark assumes there is economic withholding. There is considerable variation between the two methods and from month-to-month. The "liberal" markup index reaches 40 percent in May and December 2003. The "conservative" markup index, except for May 2003, is at or below 20 percent. This market is a relatively small portion of the California wholesale market and the market clearing prices generally are higher than the wholesale prices, which may increase the markup.

Figure VIII.3 is also a graph created by the California ISO's Department of Market Analysis, of 2003 SP 15 and NP 15 estimated short-term price-to-cost markups. For both price indices, the markup indices are at or below 20 percent and are often below ten percent. Much lower than the markups calculated for the crisis period, which were sometimes above 50 percent and were for the statewide Power Exchange.

[3]This is an estimate of the marginal cost for the markup calculation, that is similar to the Lerner Index discussed in Section I. That is, (Price - Marginal Cost)/Price, which measures the markup of price over marginal cost (as a percentage of price).

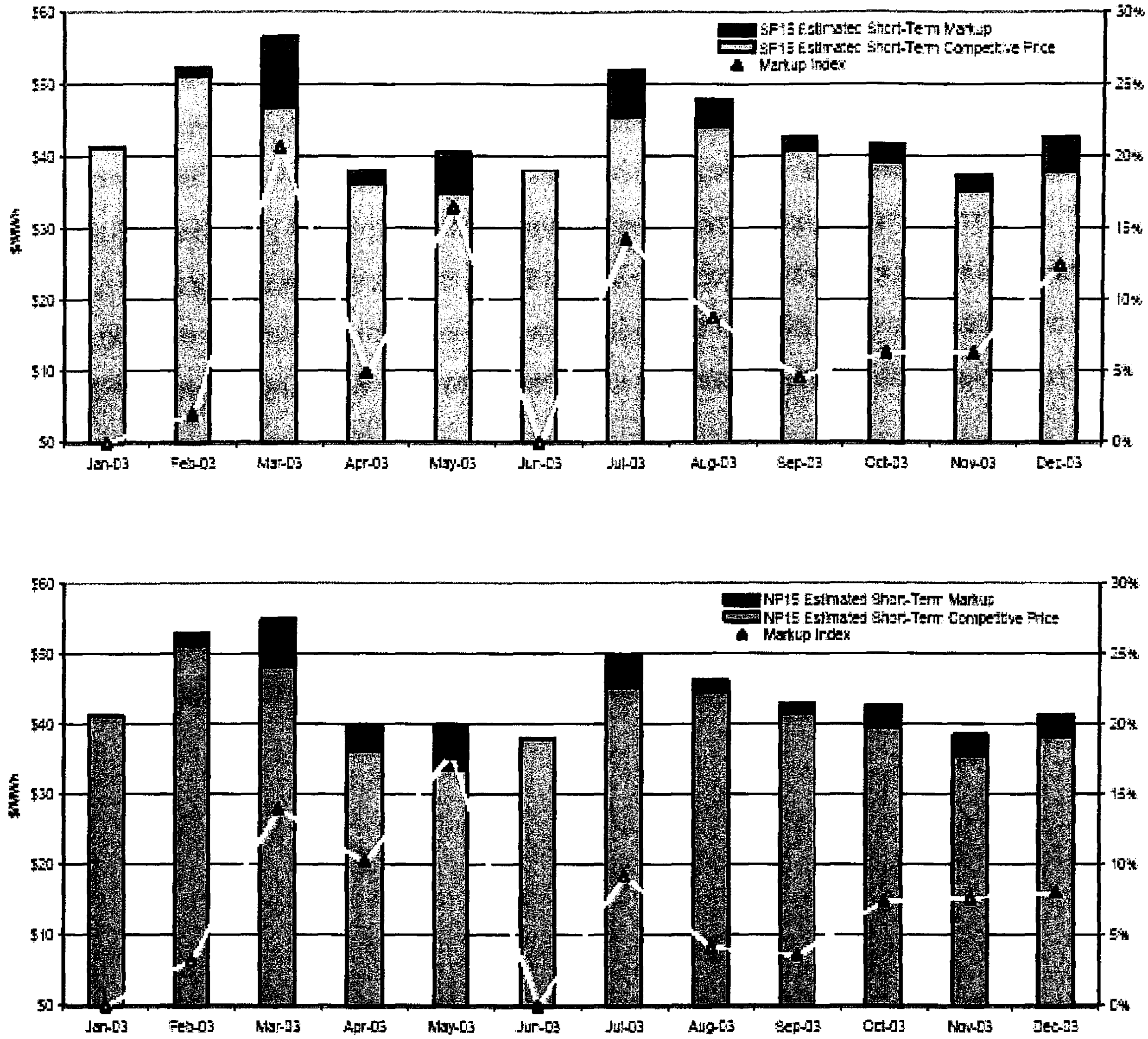

Figure VIII.3. 2003 estimated short-term price-to-cost markups indices for SP15 and NP15.
Source: Greg Cook, "2003 Annual Report on Market Issues and Performance," Board of Governors Meeting, California ISO, April 22, 2004.

Retail Markets

While there are some large retail customers in the market in California, Montana, and Oregon, in general, western state retail markets have not fully recovered from the California and western power crisis and remains relatively inactive.

Arizona

In 1996, the Arizona Corporation Commission (ACC) adopted rules that required the start of electric competition in 1999 for the utilities that the ACC regulates. Those rules were modified in 1998, 1999, and 2000. Also, in August 2002, the ACC eliminated the requirement for utilities to divest generation assets and the requirement that all power needed for standard offer service be purchased in the competitive market. The Electric Competition Act, (HB 2663), signed in 1998, allowed phased-in competition in Arizona for the utilities not regulated by the ACC. Since January 1, 2001 all areas of the state have been open to retail competition. There was an initial round of offers by alternative suppliers in 1999 and 2000, but has been no retail activity since then and now there are no customers served by alternative suppliers. In 2004, the ACC and interested parties are developing a process for standard offer competitive bidding.

California

California suspended the retail access program it already had implemented in September 2001, more than one year after the beginning of the California and western power crisis. Current law prevents customers from leaving their utility until 2013, when the long-term power contracts entered into by the state expire. Under discussion in the legislature is a bill that would create "core" and "non-core" customer groups. Core customers, residential and small business customers, would remain with the local utility. Non-core customers, large business customers, would be allowed to switch to a competitive service provider, after paying an exit fee. An earlier bill under discussion in the legislature would have essentially repealed the state's original restructuring law.

Some customers (mostly large industrial customers) that were receiving power from alternative suppliers before the suspension of retail access remain in the market.

Montana

Montana has also been dealing with the severe aftermath of the western power crisis. They implemented retail access for large industrial customers in July 1998, but residential access originally scheduled to begin by July 2002 has been postponed to July 1, 2027 (there have been two previous extensions of the transition period to retail access for smaller customers). The extension of the transition period was in a law signed by the Governor in May 2003 and would also require smaller customers to continue to be served by their distribution company in central and western Montana, but mid-sized and larger customers are still allowed to choose an alternative suppler. After Montana passed its restructuring law in 1997, there was some retail market activity early on for larger customers after retail access began. However, these larger customers paid much higher prices as a result of the western power crisis of 2000 and 2001. Many of these customers remain in the market, at this time, 87 percent of the large customer load or 34.2 percent of the total customer load in the central and western part of the state (NorthWestern's service territory) was being served by competitive suppliers.[4]

Montana Power, which at the time the restructuring law was passed was the main utility in the state, sold all its energy assets. Most of its generation assets were purchased by PPL Corporation in December 1999. In January 2001 Montana Power sold its electric and gas distribution system to NorthWestern Corporation. Montana Power then became a telecom company, "Touch America," which is now in bankruptcy. As a result of the sale, the generation assets of Montana Power became wholesale facilities that are no longer price regulated and no longer under the jurisdiction of the Montana PSC. This divestiture was voluntary and was not required by the state's restructuring law.

NorthWestern has no power plants in Montana and must purchase power in the wholesale market for its customers. NorthWestern also filed for bankruptcy protection

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[4]Personal communication, NorthWestern Corporation, August 2004.

on September 14, 2003. This was driven by NorthWestern's non-utility affiliates, not the gas and electric distribution systems in Montana.

The Montana PSC adopted guidelines in March 2003 for default supply, resource planning and procurement, and portfolio management after a roundtable process. The planning and procurement goals include having adequate, stable, reliable, and reasonably priced electric service.

Nevada

Nevada had originally planned to allow retail access for all customers but modified their restructuring law to limit access to only large customers. Nevada passed restructuring legislation AB 366 in July 1997. But, due to the California crisis, the restructuring statue was revoked in April 2001. This repeal was to halt retail access permanently and freeze utility rates until early 2002. But a law enacted in July 2001 partially restored retail access for large customers (1 MW and above) with the approval of the Commission. Customers must provide evidence of the impact from their leaving the system will have on other customers. The petition to exit their utility could be denied or an exit fee could be charged, if a significant cost is involved. Large customers have been granted permission to leave their utility in Nevada, but as of early 2004, none have actually done so due to the exit costs and transmission access.

New Mexico

New Mexico passed restructuring legislation in April 1999 that would have allowed retail access for residential, small consumers, and public school customers beginning in 2001 and all other customers by January 2002. A five year delay was enacted in March 2001. But this was rescinded in April 2003 when the Governor signed a bill that repealed the 1999 restructuring law.

Oregon

Oregon passed a restructuring law in 1999 that limited retail access to only larger non-residential customers. Retail access to these customers was set to begin by October 2001, however legislation delayed it until March 1, 2002. A small percent of the state's non-residential load (less than five percent) is served by competitive suppliers.

Biography

Kenneth Rose has been working on energy and regulatory issues for twenty years. He has testified or presented at many legislative and public utility commission hearings, proceedings, conferences, and workshops on electric industry issues and has testified before several congressional committees. Dr. Rose has worked primarily on studies concerning the electric industry and has directed or contributed to many reports, papers, articles, and books. Topics include Clean Air Act implementation, environmental externalities of electricity production, competitive bidding for power supply, regulatory treatment of uneconomic costs, market power and market monitoring, and other industry restructuring issues. He is a frequent presenter at conferences, workshops, and other instructional venues and is quoted often in national newspapers and trade publications. Dr. Rose is a Senior Fellow at the Institute of Public Utilities at Michigan State University and lectures for the School of Public Policy and Management at The Ohio State University. Dr. Rose was a Senior Institute Economist at The National Regulatory Research Institute (at OSU) from 1989 until October 2002. Prior to NRRI, Dr. Rose worked on many energy related issues at Argonne National Laboratory from 1984 to 1989. Dr. Rose received his B.S. (1981), M.A. (1983), and Ph.D. (1988) in Economics from the University of Illinois at Chicago.

PART II

STATUS OF RETAIL ACCESS AND COMPETITION

IN THE COMMONWEALTH

PART II

Status of Retail Access and Competition in the Commonwealth

Executive Summary

The first part of our fourth annual report to the Governor and the Commission on Electric Utility Restructuring ("EURC"), provided a review of recent performance of electricity power markets throughout the United States. The electricity supply industry continues to struggle following price run-ups, disclosures of accounting and data improprieties, creditworthiness issues, and volatile fuel prices, particularly natural gas. Most of the retail markets remain inactive, especially for smaller residential and commercial customers.

Part II of the Report focuses on activities in Virginia related to retail access and competition in the electricity market over the past year. It also reviews the SCC's efforts to develop a proper infrastructure to accommodate competition and to prepare Virginians for consumer choice for generation, as directed by the Restructuring Act.

At the present time, about 3.1 million electricity customers of Virginia's investor-owned utilities and electric cooperatives in Virginia have the right to choose an alternative supplier of electricity. The exception is the approximately 29,400 customers in the southwestern part of the Commonwealth exempted from the Act by legislation enacted by the General Assembly in 2003 and approximately 7,600 customers served by Powell Valley Electric Cooperative.

As we reported last year, the right to choose has not yet evolved into the ability to choose. While it is clear that the SCC, the utilities and the various stakeholders have effectively enabled almost universal retail access in Virginia, there is 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 just under 1,900 residential customers and 20 small commercial customers in Dominion Virginia Power's northern Virginia with an environmentally-friendly "green" power offer. This service is more expensive than Dominion Virginia Power's price-to-compare and the number of customers taking such service has declined from last year's report. Again, as detailed in Part I, this lack of activity is not unique to the Commonwealth; in other states currently offering retail access, few customers have the option to purchase power at a price lower than their incumbent's price-to-compare.

Over the past twelve months, the SCC, aided by the incumbent utilities and interested stakeholders, continued to make strides in preparing the Commonwealth for the arrival of competition for the generation component of electric service. Various work groups coordinated by the Staff have been assisting the SCC to provide the foundation for retail access by examining many issues, including competitive metering, supplier billing, default service and energy infrastructure. The SCC appreciates the time and effort of the respondents that have participated with these work groups.

The SCC has issued orders during the past year relating to issues such as competitive metering, market price/wires charge determination, market-based costs, regional transmission organizations ("RTO"), and pilot programs within Dominion Virginia Power's territory. Slow development of competitive activity and statewide budget constraints have caused the SCC to continue suspension of its consumer education efforts.

INTRODUCTION

In this part of the State Corporation Commission's ("Commission" or "SCC") report to the Governor and to the Commission on Electric Utility Restructuring ("EURC"), we provide an update regarding activities in Virginia related to competition in the electricity market. Since § 56-596 of the Virginia Electric Utility Restructuring Act ("Restructuring Act" or "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. At the present time, 3.1 million electricity customers in Virginia have the right to choose an alternative supplier of electricity. In compliance with the Act and this Commission's Order in Case PUE-2000-00740, all electricity customers of Virginia's investor-owned utilities and electric cooperatives are eligible to switch to a competitive supplier except for about 29,400 customers in the southwestern part of the Commonwealth[2] and approximately 7,600 customers served by Powell Valley Electric Cooperative.

As discussed later in this report, work began or continued during the past year to address restructuring issues such as those related to competitive metering, supplier billing, default service, energy infrastructure, stranded costs, and regional transmission organizations ("RTO"), to name a few.

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

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

It remains disappointing, however, that more competitive service providers have not made offers of attractively priced energy options. As in many other states that offer retail access, competitive activity has stagnated in Virginia during the past twelve months. One supplier continues to serve a small portion of customers in northern Virginia with a limited renewable resource, but no other electricity supply offers have been made.

The Commission approved Dominion Virginia Power's ("DVP") revised proposal to implement three pilot programs as a means to encourage competitive activity. These programs are just underway and it is too early to draw any conclusions. Further details will be discussed later in this report.

The following pages provide an overview of the continued transition to full retail access; the process used to develop wires charges and a price-to-compare; the status of our consumer education program; and details on a diverse list of activities and investigations devoted to the development of a competitive market.

ACTIVITY RELATED TO ACCESS

This section provides a review of activity during the past 12 months of the transition to full 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.

Transition to Full Retail Access

Allegheny Power ("AP")[3], American Electric Power – Virginia ("AEP-VA") 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 AEP-VA to provide service within their respective Virginia service territories. Only one CSP is fully registered with Delmarva but has not pursued serving customers.

Dominion Virginia Power ("DVP") implemented customer choice for its customers in three phases beginning in September 2002. DVP's phase-in was complete on January 1, 2003 when the final third of its residential customers became eligible to switch suppliers.

To date, six CSPs and aggregators are registered with DVP to provide service within DVP's 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 1,888 customers. Although PES is not currently mass-marketing its service, it continues to enroll 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.

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

The Commission Order in PUE-2000-00740 permitted the electric cooperatives ("Cooperatives") to phase-in implementation of retail access at their own pace provided it was completed by January 1, 2004. Northern Virginia Electric Cooperative's ("NOVEC") implemented retail access in July 2002. Four additional distribution cooperatives implemented retail access in 2003: Rappahannock Electric Cooperative ("REC"), Shenandoah Valley Electric Cooperative ("SVEC"), Community Electric Cooperative ("CEC"), and Southside Electric Cooperative ("SSEC").

The phase-in of retail access was complete when customers of A&N, BARC, Central Virginia ("CVEC"), Craig-Botetourt ("CBEC"), Mecklenburg ("MEC"), Northern Neck ("NNEC") and Prince George ("PGEC") Electric Cooperatives became eligible to choose a CSP on January 1, 2004. Commission approval of the retail access applications was complete by the end of 2003 to comply with its Order and the Restructuring Act to offer electricity retail choice to all of Virginia's customers by January 1, 2004.

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.[4] 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-four electric and natural gas CSPs and aggregators are licensed

[4] Guidelines to become licensed as a competitive service provider or aggregator are available on the SCC's website at: http://www.state.va.us/scc/division/eaf/compete.htm.

by the Commission to participate in full retail access. A list of licensed suppliers can be found at the end of this section.

In order to participate in an LDC's retail choice program, a CSP must also complete a registration process with the utility. Electronic Data Interchange ("EDI")[5] 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, three CSPs, Dominion Retail, PES and Washington Gas Energy Services ("WGES") are fully registered with DVP. Additionally, three aggregators, New Era Energy, EnergyWindow, Inc. and Vivex, Inc. are fully registered with DVP.

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

[5] EDI standards and guidelines are established by the Virginia Electronic Data Transfer Working Group ("VAEDT"). The VAEDT is discussed later in this report.

Licensed Competitive Service Provider/Aggregator
as of August 10, 2004

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

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 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, landfill gas from a landfill 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 1,888 residential and 20 commercial customers are enrolled with PES. No industrial customer has yet chosen a competitive electricity service provider.

Customer Participation

Pepco Energy Services began serving retail access customers in January 2002 and is currently the only active CSP. Out of approximately 3.1 million customers in Virginia who currently have the right to choose an alternative supplier of electric energy, less than 1,900 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 23, 2004.

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	1,868,436	224,063	1,856	20
AEP-VA	423,423	69,235	0	0
AP	76,587	13,903	0	0
DPL	17,961	3,145	0	0
NOVEC	106,773	7,274	0	0
REC	79,324	5,036	0	0
SVEC	27,332	4,599	0	0
CEC	8,228	1,576	0	0
A&N	9,971	723	0	0
BARC	11,164	577	0	0
CVEC	26,881	2,575	0	0
CBEC	5,609	543	0	0
MEC	28,307	1,711	0	0
NNEC	15,387	942	0	0
PGEC	8,935	1,022	0	0
SSEC	46,656	2,077	0	0
TOTAL	2,760,974	339,001	1,856	20

* Customer numbers as of December 31, 2003

FUNCTIONAL UNBUNDLING AND WIRES CHARGE

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.[6]

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 procedure 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.

[6] 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,[7] 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. This section will provide an update to the last report.

AEP-Virginia (PUE-2001-00011): By order dated June 18, 2002, the Commission approved the Company's April 30, 2002, motion requesting that the Commission hold all further proceedings on the corporate separation issues in abeyance until no earlier than July 1, 2003. On July 1, 2003, AEP-Virginia filed a Motion For Leave to Withdraw Request. The Company states that it is no longer actively pursuing legal separation at this time. AEP-Virginia requests leave to withdraw, without prejudice, its request for legal separation and further requests that this proceeding be closed. On December 24, 2003, the Commission issued an Order Granting Motion allowing AEP-Virginia to withdraw its request for legal separation and closing the case.

Wires Charge 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

[7] A bundled rate is a single rate for electricity comprised of all service elements: generation, transmission and distribution.

establish such wires charges the Commission must determine projected market prices for energy and subtract those projected market prices from each utility's embedded generation rate. According to the Act, these projected market prices and the resulting wires charges may be adjusted on no more than an annual basis. The embedded generation rate includes fuel costs as determined by the Commission pursuant to § 56-249.6.

Market price determination for full retail access began in 2001 with the market price and wires charges determinations for AEP-VA and DVP.[8] In 2002, the Commission established the market price determination methodology for the electric distribution cooperatives within the Commonwealth, and this past year, completed the determination of wires charges for all relevant electric cooperatives in the Commonwealth for 2004.

The Commission approved the basic methodology for AEP-VA 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 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

[8] Delmarva and Potomac Edison waived their right to wires charges throughout the transition period. AEP-VA waived its right to collect wires charges consecutively for calendar years 2002 though 2004, and recently waived its right to wires charges during calendar year 2005.

prices"[9] for electric power traded in the wholesale market. The Commission made this decision in the beliefs that forward prices are the most appropriate indicators of projected market prices and that forward markets were functioning reasonably well.

The forward price method considers prices at two delivery/receipt points (Cinergy and PJM West) for a calendar year of data. Although DVP has incorporated a value for capacity in the Company's 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.

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 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 additional "headroom" for CSP's entering the Virginia retail electricity market.

At the time that the Commission allowed the incorporation of the capacity adder into DVP's projected market prices, it declined to allow certain proposed changes to DVP's CSP Coordination Tariff that the company had proposed concomitantly with its capacity adder proposal. Although DVP maintained that the tariff changes were necessary to make the

[9] "Forward prices" generally refer to agreements made today for the future purchase and sale of a specified quantity of electric power at some specified location for a specified time period.

company whole in the event of a CSP default, the Commission was concerned that the proposed changes might have had a negative effect on CSP participation in the Virginia retail market. The Commission, however, did not preclude DVP from proposing risk mitigation measures in the future if they were found necessary.

In 2003, DVP again proposed changes to its CSP Coordination Tariff. As in the previous year, these changes were intended to minimize the financial risks of including the capacity adder in the company's projected market prices. The company modified its proposed changes somewhat from the previous year, and in particular, did not seek the ability to recover through a fuel proceeding any lost revenues due to non-compliance of a CSP with the tariff. In accepting the proposed revisions, the Commission specifically prohibited the use of a fuel proceeding to recover any lost revenue due to tariff non-compliance by a CSP and stated that the recovery of any such lost revenues must be accomplished through DVP's approved tariff provisions.

The projected market prices for DVP for 2004 remain below the company's capped generation rates. As such, wires charges are applicable to DVP customers that choose to take service from a CSP during 2004. On July 1, 2004, DVP submitted an application to impose a wires charge in 2005. This application is currently under review by Staff.

This year, AEP-VA 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.[10] AEP-VA's decision not to seek wires charges for 2005 implies that market prices for 2005 within its service territory will again be above its capped generation rate.

[10] Although this decision by AEP-VA leaves the issue of the company's calculation of its transmission cost adjustment to its projected market prices unresolved, the issue remains moot for 2005. To date, the Commission has not accepted AEP-VA's methodology for calculating this adjustment given that AEP-VA's proposed adjustments have been significantly higher than the Commission deems reasonable.

With respect to the electric distribution 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 AEP-VA should be utilized by the Virginia electric distribution cooperatives,[11] 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 AEP-VA. Whereas, the capped rate 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.

The approval process of projected market prices for the respective Cooperatives began in 2002 and was completed by early 2004. With the exception of Central Virginia Electric Cooperative, which did not seek to collect wires charges, the capped rates of the remaining Cooperatives are in excess of the projected market prices within the respective service territories of these Cooperatives; therefore, customers of those Cooperatives who switch to CSPs must pay a wires charge to the cooperative serving them.

Price-to-Compare

[11] 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.

Once rates have been unbundled and the appropriate wires charge has 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.

Among investor-owned utilities, only DVP imposed a wires charge component for 2004 to be included within its price-to-compare. Each of the cooperatives implementing retail access in 2004, with the exception of Central Virginia Electric Cooperative, also included a wires charge component within the respective price-to-compare.

The table below shows the prices-to-compare for the investor-owned utilities in Virginia required to implement retail competition. A similar table for the electric distribution cooperatives that have implemented retail competition 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 2004 price-to-compare values for the subject investor-owned utilities are:

Customer Class	Dominion Virginia Power	AEP Virginia	Allegheny Power	Conectiv
Residential	4.276¢/kWh	3.246¢/kWh	3.87¢/kWh	5.47¢/kWh
Small Commercial	4.320¢/kWh	3.067¢/kWh	3.96¢/kWh	5.94¢/kWh
Large Commercial	3.949¢/kWh	3.585¢/kWh	3.90¢/kWh	Not applicable
Small Industrial	3.812¢/kWh	2.962¢/kWh	3.55¢/kWh	5.58¢/kWh
Large Industrial	3.535¢/kWh	2.781¢/kWh	3.34¢/kWh	5.49¢/kWh
Churches	4.157¢/kWh	2.984¢/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 2005. 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 wires charges imposed pursuant to § 56-583 of the Act. The Commission initiated a proceeding with its Order of June 16, 2004 in Case No. PUE-2004-00068, to permit an exemption to the current payment of wires charges.

Such amended legislation provides an opportunity for large industrial and commercial customers, and aggregated customers in all rate classes subject to aggregated demand criteria as may be established by the Commission, to switch to a CSP without paying wires charges if those customers agree to pay market-based costs for electric energy upon return to an incumbent LDC or default provider. Customers are permitted to avoid wires charges and participate in this program on a first-come, first-served basis until the accumulative billing demand of transferred customers reaches 1000 MW or eight percent of such LDC's adjusted peak-load within 18 months after the program is implemented. Additionally, such customers may not return to the incumbent electric utility or default provider thereafter under capped rates.

The recent Commission Order charged the Staff to invite interested parties to participate in a work group to assist the development of the rules, as well as an appropriate methodology, necessary to implement this new statutory provision. Several questions were also included in the Commission Order for interested parties to provide responses to prompt discussion at the initial work group meeting held on August 19, 2004. Such discussions will continue over the next several weeks. The Staff is directed to submit its report within 30 days of the last work group meeting which is expected to be this fall.

CONSUMER EDUCATION

The "quiet" period for the Virginia Energy Choice ("VEC") consumer education program continued for the past year with limited resources focused on maintaining a website, a toll-free information line, responding to requests for printed materials, and completing the remaining consumer education grant projects. VEC suspended all market research, advertising, public relations, and major grassroots outreach activities on March 1, 2003.

The VEC website (www.vaenergychoice.org) has extensive information on the changes coming to the energy market in Virginia and is routinely updated. The site receives between 8,000 and 10,000 individual visits per month. Web visitors can print information sheets or request consumer guides be mailed to them. The SCC also responds to an average of 20 email inquiries per month from the site.

The VEC toll-free information line (1-877-YES-2004) is supported by an automated system that provides callers with the choice of listening to a brief recording on energy restructuring, leaving address information to receive consumer education materials, or requesting a call from SCC staff. The information line receives between 500 and 600 calls per month.

Two consumer education projects funded with VEC grants were completed in the past year. A total of 10 community-based organizations have participated in the grant program to disseminate information to consumer groups with special needs. Funds were used to print special brochures on energy choice topics, distribute consumer information, or conduct workshops. VEC shared these outreach ideas with organizations that have participated in the grassroots program through an electronic newsletter called "The Source." The periodic distribution of the newsletter is planned to continue through the "quiet" period in order to keep those who are interested informed about energy choice.

The SCC continues to receive the advice and input from the Virginia Energy Choice Education Advisory Committee. The committee members represent investor-owned utilities, electric cooperatives, consumer groups and competitive suppliers. With the likelihood of limited minimal retail energy market activity in the coming year, the SCC and the committee agreed to maintain the Virginia Energy Choice consumer education program at the existing modest level and provide for necessary updates to education materials. With the participation of the committee, the SCC will determine the size and scope of future energy choice outreach activities as market conditions warrant.

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.[12] The Rules Governing Retail Access to Competitive Energy Services ("Retail Access Rules" or "Rules"), adopted by Commission Order in Case No. PUE-2001-00013,[13] 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

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[12] 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.

[13] The Rules Governing Retail Access to Competitive Energy Services are available on the Commission's website at: http://www/state/va/us/scc/division/restruct/main/rules/teirrules.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.[14]

Minimum Stay Provisions

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 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, to permit an exemption to the current minimum stay requirement.

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.[15] The statutory exemption permits such customers to elect to accept market-based costs for electric energy as an alternative to being subject to the 12-month minimum stay provision. The recent Commission Order charged the Staff to invite interested parties to participate in a work group to assist the development of the rules, as well as an appropriate methodology, necessary to implement this new statutory provision. Several questions were also included in the Commission Order for interested parties to provide responses to prompt discussion at the initial work group meeting held on August 19, 2004. Such discussions will continue over the next several weeks. The Staff is directed to submit its report within 30 days of the last work group meeting which is expected to be this fall.

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[14]Dockets regarding restructuring issues may be found on the SCC's website at: http://www.state.va.us/scc/caseinfo.htm .

[15] 20 VAC 5-312-80 Q

Competitive Metering Provisions

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

In addition, the Commission directed the Staff and the competitive metering work group to continue to study the possibility of the utilities establishing voluntary time-of-use rate programs for residential and small commercial customers and to expand these efforts to consider new meter technology including examining the types of meters the utilities use, and for the Staff to file a report on or before May 1, 2004, providing the results of its investigation. The Staff filed its report on April 28, 2004,[16] advising that it is premature to implement additional elements of competitive metering and recommending that the Staff and the work group continue to monitor regulated and competitive market developments in metering. The Commission provided interested parties an opportunity to comment on the Staff's report by June 1, 2004.

Following comments to the Staff Report submitted by three parties, the Commission entered its Order on July 16, 2004, adopting the recommendations of the Staff Report.

Competitive Billing Provisions

On August 31, 2002, the Commission issued an Order in Case No. PUE-2001-00297, adopting rules for CSP consolidated billing.[17] The Commission also found that an EDI workaround approach for implementation of CSP consolidated billing was reasonable on an

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[16] The report may be found at: http://docket.scc.state.va.us:8080/vaprod/main.asp .
[17] The adopted rules may be found at: http://www.state.va.us/scc/caseinfo/pue/case/e010298b.pdf .

interim basis, recognizing that such approach will need to be replaced with standardized EDI protocols as the competitive market develops and the volume of competitive billing increases.

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.[18] By Order dated April 9, 2003, the Commission issued an Order adopting a change to Retail Access Rule 20 VAC 5-312-20 D and reaffirming our direction to Staff to file two reports on or before July 1, 2004. One report related to the impact on the development of a competitive market, of incumbent-affiliated competitive service providers and their activities in affiliated LDC's service territories. The second report related to the impact of aggregation contracts, particularly regarding exit fees, on the development of competitive retail markets in the Commonwealth

On June 28, 2004, Staff filed a report detailing both issues as required. Staff noted in its report that there has been no aggregation activity in the Commonwealth. Therefore Staff was unable to study the two issues as directed. However, Staff noted that the Commission recently approved three pilot programs offered by DVP and are expected to commence this fall, with one pilot specifically focused on municipal aggregation. Staff expressed belief that these pilots may result in aggregation activity that may permit the two issues mentioned above to be addressed. The Commission recognized the current lack of aggregator activity in its Order of

August 25, 2004, by concluding this matter and dismissing it from the docket of active cases. These issues may be revisited in the future if market conditions warrant further review.

Distributed Generation

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

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

Chapter 827 of the 2004 Acts of the General Assembly amended the net metering provisions of the Code of Virginia, Section 56-594 of the Restructuring Act to revise the definition of eligible customer generator. The definition now refers to a nonresidential customer that owns and operates an electric generation facility that, among other things, has a

[18] Available at http://www.state.va.us/scc/caseinfo/pue/e020174.htm .
[19] In May of 2000, the Commission issued rules governing net energy metering promulgated pursuant to § 56-594 of the Restructuring Act. The net metering rules establish interconnection guidelines and tariffs under which an electric customer may interconnect a small wind, hydro or solar generating facility to the grid. The rules may be found at: http://www.state.va.us/scc/caseinfo/pue/case/e990788rul.pdf .

capacity of not more than 500 kW. The capacity limit for nonresidential customers previously was 25 kW.

In response to this statutory change, by Order dated June 3, 2004, the Commission established Case No. PUE-2004-00060. This proceeding to amend the current Regulations Governing Net Energy Metering adopted in 2000 permits interested parties to submit comments or a request for hearing by July 19, 2004 and Staff to file a report of its findings and recommendations by August 25, 2004. Several parties filed comments raising substantial issues. DVP filed a motion for leave to submit reply comments, to modify the procedural schedule and to permit the convening of a work group to assist Staff's consideration of the complex issues raised. Several parties support DVP's motion which is now pending before the Commission.

Business Practices

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

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

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

conference calls to update regulators and continues to serve on the Advisory Committee to NAESB.

Virginia Electronic Data Transfer Working Group

The Staff continues to serve as a facilitator for the Virginia Electronic Data Transfer ("VAEDT") Working Group to develop standards and guidelines for electronic data interchange ("EDI"). EDI is a means for a utility and a CSP to communicate electronically and involves the computer-to-computer exchange of business and customer information that is required to transact business between CSPs and LDCs. The current Virginia Plan, Implementation Guidelines, and EDI Test Plan[21] are on file with the Commission for informational purposes. Because of current inactivity, the VAEDT has not been as active and intends to meet this fall to discuss potential issues relating to membership within PJM.

The VAEDT continues to support efforts of the First Regional Electronic Data Interchange ("FREDI")[22] to establish and maintain uniform criteria across the Mid-Atlantic region[23] and more easily exchange electronic information between electric utilities operating in multiple jurisdictions. This effort served as the basis for NAESB's on-going 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.

Generation and Transmission Additions

Since 1998, ten generating plants have been built and placed into commercial operation within the Commonwealth, adding 3,682 megawatts ("MW") to existing generation physically located in Virginia.[24] Approval of seven additional facilities has been granted by this

[21] Additional information available at: http://www.vaedt.org .
[22] Additional information available at: http://www.firstregionalEDI.org .
[23] Currently comprised of jurisdictions from DC, DE, MD, NJ, PA, OH, and VA.
[24] These new plants are comprised of three Dominion generating stations, one ODEC facility, and six independent

Commission summing to 4,333 MW, of which one facility is under construction and should be ready for operation by the fall of 2004. Another certificated facility of 680 MW has since been withdrawn. The remaining facilities, totaling 3,185 MW, are in various stages of development to move forward. In addition, seven independent power producers submitted applications for generating capacity of 5,430 MW, but withdrew their requests prior to receiving certificates. The table at the end of this section provides further detail regarding applications for new facilities.

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

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

Expansion of transmission facilities is also needed to accommodate expected customer demand and required energy supply. The SCC granted permission to AEP-VA to construct a 765-kV electric transmission line in southwestern Virginia. That line is under construction and

power plants, representing 1,500 MW, 472 MW, and 1,710 MW, respectively.

is expected to be operational in late 2006. Applications for a few smaller transmission lines have been approved or are currently pending before the SCC. Additionally, several new natural gas pipelines are now in service or have been approved.

By order dated August 21, 2002, the Commission adopted filing requirements for applications filed on or after September 1, 2002.[25] In the August 21st Order the Commission also concluded that, due to the passage of SB 554[26], filing requirements addressing cumulative environmental impacts are not necessary and therefore are excluded from the Commission's filing requirements.

The Restructuring Act as amended by the 2004 Session of the General Assembly as Senate Bill 651, extended by two years the expiration date of certain certificates granted by the Commission. Those certificates to construct and operate electrical generating facilities for which applications were filed with the Commission prior to July 1, 2002, will receive the two-year extension.

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[25] The amended rules may be found at: http://www.state.va.us/scc/caseinfo/pue/case/e010655a.pdf .

[26] The adopted rules may be found at: http://www.state.va.us/scc/caseinfo/pue/e010313.htm. Senate Bill No. 554 was signed by Governor Warner on April 4, 2002, and became effective on July 1, 2002. The bill modified the Commission's role in reviewing the environmental aspect of appliations to construct electric generating facilities in Virginia.

Summary of Construction Activity in Virginia
As of August 10, 2004

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 (1/16/01)	885 MW	Fluvanna County	PUE010039	Gas CC	May 04	3/13/02	4/19/02
INGENCO Wholesale Power, LLC (11/13/03)	16 MW	Chesterfield County	PUE-2003-00538	48-LFGas	Jun 04	none	4/12/04
	3,682 MW						
New power plants with SCC certificates currently under construction.							
Marsh Run Generation, LLC (12/28/01)	**468 MW**	Fauquier County	PUE020003	3-GasCT	Sep 04	5/21/02	SCC app 11/6/02
New power plants with SCC certificates, but not yet under construction.							
Competitive Power Ventures (8/31/01/2/02)	520 MW	Fluvanna County	PUE010477	Gas CC	spr 06	1/9/02	SCC app 10/7/02
Tenaska Virginia Partners II, LP (8/15/01)	900 MW	Buckingham County	PUE010429	Gas CC	n/a	5/28/02	SCC app 1/9/03
CPV Warren, LLC (2/14/02)	520 MW	Warren County	PUE020075	2-GasCC	spr 05	7/24/02	SCC app 3/13/03
Chickahominy Power, LLC (1/4/02)	665 MW	Charles City County	PUE010659	Gas CT	n/a	5/1/02	SCC app 3/12/04
James City Energy Park, LLC (3/8/02)	580 MW	James City County	PUE-2002-00150	2-GasCC	win 05	9/18/02	SCC app 3/12/04
White Oak Power Co., LLC (5/9/02)	680 MW	Pittsylvania County	PUE-2002-00305	4-Gas CT	sum 04	10/24/02	SCC app 8/1/03,w/drawn
	3,865 MW >>> 680 withdrawn **leaving 3,185 MW**						
New power plants that have applied for an SCC certificate							
Duke Energy Wythe, LLC (12/27/01)	620 MW	Wythe County	PUE010721	Gas CC	sum 04	6/25/02	**Dismissed 5/20/04**
CinCap-Martinsville	330 MW	Henry County	PUE010169	4-GasCT	sum 03	9/18/01	**Dismissed 4/29/03**
Kinder Morgan VA, LLC	560 MW	Cumberland County	PUE010722	Gas CC	sum 04	12/17/02	**Dismissed 1/14/03**
Kinder Morgan of Virginia, LLC	550 MW	Brunswick County	PUE010423	Gas CC	win 04	11/7/01	**Dismissed 11/1/02**
Henry County Power/Cogentrix (MB)	1,100 MW	Henry County	PUE010300	Gas CC	sum 04	10/17/01	**Dismissed 8/26/03**
Loudoun County Power/Tractebel (WS)	1,400 MW	Loudoun County	PUE010171	Gas CC/CT	04/05	12/6/01	**Dismissed 3/27/02**
Mirant Danville, LLC (KH)	870 MW	Pittsylvania County	PUE010430	Gas CT/CC	03/04	12/5/01	**Dismissed12/16/03**
Total	**5,430 MW** >>> withdrawn/dismissed **leaving 0 MW**						

*Commercial Operation Date

Company/Facility	*Size*	*Location*	*Docket*	*C.O.D.*	*Order*
Transmission lines					
AEP-VA	765 kV-90 mi	Wymoing-Jackson's Ferry	PUE970766	2006	5/31/01 approved, under construction
DVP	500 kV-101 mi	Joshua Falls-Ladysmith	PUE910043	n/a	revised 5/02 and continued
DVP	230 kV- 4 mi	Loudoun	PUE010154	n/a	6/27/02 approved conditionally
DVP	500 kV-8 mi	Morrisville-Loudon	PUE-2004-00062	5/07	pending
DVP	230kV – 11.8 mi	Trabue-Winterpock	PUE-2004-00041	11/06	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 Loudon	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 4/9/04 for AP to file cost/benefit analysis by 6/18/04, Staff report on 8/23/04 and hearing on 9/28/04.
Conectiv (PJM East)	PUE-2001-00353	Order of 5/20/04 recognizes current membership in PJM since 3/97 **SATISFIES** RTE Rules.
KU (MISO)	PUE-2000-00569	**EXEMPT** 2003 via §56-580 G
AEP (PJM West)	PUE-2000-00550	Order of 1/15/04 setting 6/22/04 for Staff Report & hearing on 7/27/04.
DVP (PJM South)	PUE-2000-00551	Order of 12/22/03 setting 8/16/04 for Staff Report & hearing on 10/12/04.

Energy Infrastructure Study

Senate Bill 684, enacted by the 2002 Session of the General Assembly, requires 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 EURC 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 EURC's consideration. The EURC 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 EURC, on or before July 1, 2003, and to provide subsequent reports as the Commission deems necessary or as requested by the EURC.

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 is currently collecting updated data and will report to the EURC on this matter in the near future.

RTE Development

Section 56-579 of the Restructuring Act requires incumbent electric utilities to establish or join regional transmission entities ("RTEs")[27] as part of the transition to retail competition. This obligation is imposed on each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity. Section 56-579 also requires the State Corporation Commission to determine "whether to authorize transfer of ownership or control from an incumbent electric utility to a regional transmission entity." Behind this requirement was an expectation that RTEs would manage and control the transmission assets of Virginia's utilities with the objective of meeting the transmission needs of electric generation suppliers both within and outside Virginia.[28]

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

[27] RTE and RTO (Regional Transmission Organization) are essentially synonymous terms. The former is used in the Act; the latter is the Federal Energy Regulatory Commission ("FERC") preferred acronym.
[28] § 56-579 A 2 d.

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

Three of Virginia's incumbent electric utilities, Kentucky Utilities, Allegheny Power and Delmarva, have shifted management of their transmission facilities to an RTE. Delmarva and AP are participating in PJM[29] and KU is participating in the MISO.[30]

Virginia Power and AEP, along with a number of other utilities, sought to form the Alliance RTO which was rejected by the FERC on December 20, 2001. On April 25, 2002, FERC issued an order directing the Alliance Companies to make compliance filings detailing which RTO(s) they plan to join, collectively or individually. On May 28, 2002, AEP made a compliance filing noting its intention to join PJM West. Virginia Power also made a filing on that date noting that it was soliciting input from its stakeholders. On July 15, 2002, Virginia Power filed an update to its earlier filing notifying that the Company had entered into a MOU to join PJM as "PJM South."

On July 31, 2002, FERC issued an order conditionally accepting AEP's and Dominion Virginia Power's filings. Both utilities have entered into implementation agreements with PJM. These agreements reflect financial commitments by both companies to fund certain PJM expansion related costs and set forth schedules for the proposed expansions. The following discussion will provide additional information regarding the status of individual RTE proceedings currently pending Commission approval.

[29] 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.

[30] "MISO" is the Midwest Independent System Operator. MISO began offering transmission service over KU's transmission facilities on February 1, 2002.

AEP-VA

AEP-Virginia filed a substitute application for approval to transfer functional control of its transmission facilities to PJM on December 19, 2002. The Commission issued a scheduling order, in Case No. PUE-2000-00550,[31] regarding that application on March 7, 2003. That order required AEP "to develop, as soon as practicable, but no later than 90 days, after a final SMD rule has been adopted, a study of the costs, benefits, and resulting cash flows that would arise from the transfer of AEP-VA's transmission assets to PJM. The Company shall submit a report detailing the methodology, key assumptions, and results of the cost/benefit analysis from the perspective of AEP, AEP-VA, other AEP corporate entities, AEP shareholders, AEP-VA's customers, and Virginia ratepayers as a whole." The order also noted that the Commission expected: "the cost/benefit analysis to include at a minimum an examination of (1) how participation in PJM would impact AEP-VA's fuel factor during the capped rate period; (2) market prices for generation as compared to current cost of service based generation pricing; (3) transmission rates for the recovery of embedded transmission costs; (4) transmission congestion costs incurred under the locational marginal pricing ("LMP") construct; and (5) the availability and effectiveness of transmission rights for "hedging" against transmission congestion charges. The study also should include a sensitivity analysis to evaluate and identify critical assumptions including, but not limited to, the following: (1) differing load forecasts; (2) differing levels of transmission congestion and associated transmission rights; (3) abnormal vs. normal weather; (4) differing unit outage assumptions; and (5) differing fuel cost projections (higher or lower gas costs vs. coal costs, for example). Finally, the study should include a discussion of how the completion of the planned Wyoming to Jackson's Ferry 765 kV line might impact study results."

On November 7, 2003, the Commission entered an Order pursuant to which the Commission amended the March 7, 2003 Order to require the Company to file additional relevant information quantifying the net costs of the Company's proposal with respect to various stakeholder groups under six scenarios.

On March 14, 2003, the public utilities commissions of Ohio, Michigan and Pennsylvania filed a motion requesting that the FERC direct that AEP transfer control of its transmission facilities to PJM, irrespective of pending state regulatory approvals. Exelon Corporation and Commonwealth Edison Company filed in support of the motion on March 17, 2003. This Commission filed a response to those motions on April 1, 2003. The Commission's response sought to preserve state authority and argued against federal preemption. On that same day, the FERC approved AEP's request to join PJM but did not direct that AEP join by a date certain thereby avoiding any ruling regarding state authority relative to RTO participation. Thereafter, the Commission filed a request for rehearing on May 1, 2003, questioning the FERC's decision to grant approval on the basis that the record was devoid of any factual basis for the FERC finding that AEP's transfers of control of its facilities to PJM would be consistent with the public interest. Significantly, and as emphasized in the Commission's request for rehearing, the application lacked, among other things, information identifying the actual facilities whose control was proposed to be transferred from AEP to PJM. AEP's application was similarly silent concerning the impact of the proposed transfers on customers' rates for power and energy. The Commission's request, as well as various other motions for reconsideration, is currently pending.

On June 26, 2003, the FERC Staff issued data requests to PJM and AEP seeking information regarding the possibility of transferring control of only a portion or portions of

[31] See http://www.state.va.us/scc/caseinfo/pue/e000550.htm

AEP's transmission system to PJM. PJM filed responses basically concluding that partial integration of the AEP system was feasible from a technical and operational perspective. By its own admission, PJM did not address any "federal or state legal or regulatory concerns or issues that might arise about dividing AEP-East's facilities ...." AEP filed responses with quite different conclusions. AEP noted that partial integration would result in a long list of quite serious negative consequences, including; (1) increasing the cost to serve AEP customers, (2) violating Commission requirements pertaining to single-tariff service over a single holding company system, (3) potentially creating a seam within AEP-East where none has existed previously, (4) decreasing planning and operational efficiencies, (5) contradicting Commission policies which favor the regionalization of tariff and reliability functions, (6) complicating the pending AEP applications in non-transferring states, and (7) creating intra-company operational barriers for the first time for those individual AEP operating companies that serve customers in more than one state. On July 16, 2003, the Commission filed comments supporting AEP's position and criticizing PJM's response with the FERC.

On July 17, 2003, the Kentucky Public Service Commission ("KPSC") denied AEP's application to transfer control of its major transmission lines in Kentucky to PJM. The KPSC determined that the proposed transfer would not be in the public interest because it would impose costs on Kentucky Power ratepayers without providing demonstrable benefits. The KPSC cited the following factors in denying Kentucky Power's application to join PJM:

- Kentucky Power would pay $3 million annually in membership fees, but could show no quantifiable benefits of membership in PJM.

- Kentucky Power has low costs and reliable transmission, so is unlikely to benefit from membership in PJM.

- PJM could in the future set a single wholesale electricity rate for its entire system, a move that would significantly raise rates for Kentucky Power customers.

- If Kentucky Power joins PJM, the RTO could decide which customers in the overall system get priority in the event of power shortages. That conflicts with Kentucky law that requires utilities in the state to give priority to the "native load" in their service territories. The PSC has no authority to override that law.

AEP filed a petition for rehearing of the Kentucky decision on August 6, 2003. The petition was granted and rehearing was scheduled for April 21, 2004.

On September 12, 2003, the FERC issued an "Order Announcing Commission Inquiry into Midwest ISO-PJM RTO Issues." The order directs AEP, among others, to have a senior company official present at an inquiry to be held on September 29 and 30, 2003. AEP must file prefiled testimony discussing impediments to its voluntary commitment to join an RTO by September 23. The order also invites state commission representatives to the inquiry. The Commission filed a motion for reconsideration of the September 12 order on September 24, 2003 and was represented at the FERC hearings held on September 29 and 30. The Commission also filed comments concerning AEP's partial integration proposal on October 9, 2003.

On November 25, 2003, in Docket No. ER03-262-009, FERC issued its "Order Making Preliminary Findings and Giving Public Notice and Setting Matter for Public Hearing under PURPA Section 205 (A)," in which it preliminarily found that AEP should be exempted from complying with either the orders of the Kentucky Public Service Commission or the provisions of the Virginia Electric Utility Restructuring Act because these "are preventing AEP from fulfilling both its voluntary commitment in 1999, as part of merger proceedings, to join an RTO, and its application to join an RTO pursuant to the Commission's Order No. 2000."

The FERC convened a public hearing on this matter on January 26, 2004. Briefs were filed on February 12, 2004, and oral argument in lieu of reply briefs was held on February 24, 2004. The Administrative Law Judge filed recommendations on March 15, 2004.

On April 20, 2004, the parties to the Kentucky Power RTE proceeding presented the KPSC with a proposed stipulation, which would settle the matter by allowing AEP to transfer its Kentucky Power transmission facilities to PJM control, subject to certain conditions. On May 19, 2004, the KPSC approved the stipulation and allowed Kentucky Power to transfer control of its major transmission lines to PJM subject to certain conditions. The stipulation affirms the KPSC's authority over Kentucky Power's retail rates, the KPSC noted in its order. "This affirmation of this Commission's authority, coupled with the voluntary nature of PJM's energy market for meeting Kentucky Power's native load energy requirements, provides adequate assurances that Kentucky Power's retail energy costs will continue to be fair, reasonable, and relatively stable over time, and not subject to market price variations," the KPSC said. The KPSC also sought to be dismissed from the FERC in Docket No. ER03-262-009 proceeding on the grounds that its May 19 order renders the question moot.

On June 17, 2004, the FERC issued an "Opinion on Initial Decision and Order on Rehearing" Docket No. ER03-262-009 that:

- Affirmed the FERC's initial finding that it could act under section 205(a) of the Public Utility Regulatory Policies Act of 1978 (PURPA)[32] and permit AEP to integrate into PJM over the objection of the Commonwealth of Virginia.

- Recognized that the Virginia Commission is considering whether AEP-VA should join PJM and noted that while the FERC would prefer that Virginia complete its state proceeding prior to its decision in No. ER03-262-009 that the current schedule does not provide for the Virginia Commission's hearing to begin until July 27, 2004.

- The FERC further noted that it was concerned that such a schedule will not provide adequate notice to the market participants to permit AEP to join PJM as of October 1, 2004, the date set forth in our November 25, 2003 Order. The FERC stated that AEP, PJM, and their customers need greater certainty for the integration to be able to proceed on that date, and therefore invoked its authority under PURPA section 205.

[32] 16 U.S.C. § 824a-1(a) (2000).

- Finally the FERC noted, to the extent that the Virginia Commission is able to complete its proceedings prior to the date of integration and reaches agreement as to reasonable conditions relating to integration that do not prevent or prohibit integration, that it would be open to considering such provisions.

In a separate order issued on June 17, 2004, the FERC approved the Kentucky settlement.

On June 29, 2004, the Commission filed an Emergency Motion with the FERC in Docket No. ER03-262-009. The motion requested that the FERC issue an order staying the effectiveness of its June 17 opinion and order by no later than July 15, 2004. The FERC denied that motion for stay on July 15, 2004. On July 29, 2004, the Commission filed a Motion for Expedited Reconsideration of the FERC's July 15 Order. In that motion, the Commission noted that parties to the Virginia proceeding regarding the transfer of control of AEP's transmission facilities to PJM's had entered into a Stipulation that would enable the Commission to approve the proposed transfer and that approval of the Stipulation by the Commission would moot the issues addressed in Opinion No. 472 concerning the laws, rules and regulations of the Commonwealth of Virginia. On August 3, 2004, the FERC issued an order staying its opinion and order until September 2, 2004. It should also be noted that on July 16, 2004, the Commission filed with the FERC a motion requesting rehearing of the FERC's June 17, 2004, decision in this matter.

In a related filing, the Commission filed a Petition for Writ of Mandamus to the Federal Energy Regulatory Commission in the United States Court of Appeals for the District of Columbia Circuit on July 21, 2004. In that petition, the Commission requested that the Circuit Court stay the effectiveness of the FERC opinion and order until the FERC's order on rehearing is issued, and the matter can then be fully considered on appeal by the Circuit Court.

The Commission issued a procedural schedule in PUE-2000-00550 setting the matter for notice and hearing on January 15, 2004. AEP was directed to file testimony and exhibits by

March 1, 2004; respondents were directed to file testimony and exhibits by May 24, 2004; and Staff was directed to file testimony and exhibits by June 22, 2004. The public hearing took place on July 27, 2004. During the hearing, AEP-VA; the Commission's Staff; the Division of Consumer Counsel of the Office of the Attorney General; the Old Dominion Committee for Fair Utility Rates; PJM; and Edison Mission Energy offered a stipulation recommending that the Commission approve AEP-VA's participation in PJM subject to certain specified conditions. The conditions set-forth in the stipulation included agreements by AEP-VA and the parties regarding future ratemaking proposals that may come before the Commission; modest bill credits for the period 2005-2010; a curtailment protocol specifying conditions under which service to Virginia consumers may be curtailed; and information reporting requirements for AEP-VA and PJM. On August 2, 2004, the Commission issued an Order Requesting Comments on a proposed modification to the curtailment protocol specified in the stipulation. This matter is now pending a Commission decision.

Allegheny

Allegheny filed an application to transfer control of its transmission facilities to PJM under an arrangement known as PJM West. On August 16, 2001, the Commission issued an Order Prescribing Notice and Inviting Comments and/or Requests for Hearing that established a procedural schedule for this matter, Case No. PUE-2000-00736.[33] On October 26, 2001, Staff filed a report supporting Allegheny's application and its membership in PJM West. However, the Staff noted that it was unknown what would occur as a result of the FERC-ordered mediation involving PJM, Allegheny, the New York Independent System Operator, and ISO New England. The Staff, therefore, recommended that the Commission either delay

[33] See http://www.state.va.us/scc/caseinfo/pue/e00736.htm

acting on, or grant only conditional approval of, Allegheny's request to transfer management and control of its transmission facilities in order to permit Staff to review any FERC order in the Northeast RTO proceeding.

On January 30, 2002, FERC issued an Order that, among other things, permitted Allegheny and PJM to form PJM West, effective March 1, 2002. On May 9, 2002, the Commission issued an order noting that much had occurred regarding the development and implementation of PJM West and that those developments may have affected the accuracy and completeness of the information included in Allegheny's application. Accordingly, the Commission required Allegheny to update its application.

On July 12, 2002, the Staff filed a Supplemental Report recommending that the Commission delay approval of Allegheny's application until more information was known about the ITC proposal for PJM West, Dominion's PJM South proposal, and the outcome of PJM and MIS0 discussions to form a single energy market across the PJM and Midwest regions.

On May 30, 2003, the Commission issued an order requiring Allegheny to develop and file a study of the costs, benefits, and resulting cash flows that would rise from the transfer of Allegheny's transmission assets to PJM within 90 days of FERC's adoption of a final rule pertaining to SMD.

Potomac Edison has turned over operational control of its transmission facilities to PJM and currently operates under the LMP model. A procedural schedule setting this matter for notice and hearing was issued on April 9, 2004. Potomac Edison was directed to submit an analysis of the comparative costs and benefits of its participation in PJM by June 18, 2004. Respondents were directed to file testimony and exhibits by July 26, 2004, and Staff was directed to file testimony and exhibits by August 23, 2004. The public hearing is scheduled for September 28, 2004.

Delmarva

On October 16, 2000, Delmarva filed a Motion with the SCC in Docket No. PUE-2000-00086[34], requesting the Commission to determine that Delmarva's membership in PJM constituted compliance with the requirements of the Restructuring Act and the SCC's Regulations Governing Transfer of Transmission Assets to Regional Transmission Entities, 20 VAC 5-320-10 *et seq.* ("RTE Rules").

On June 1, 2001, the SCC issued a procedural order prescribing notice and inviting comments on Delmarva's request. By Order dated June 22, 2001, the SCC created a separate docket, Case No. PUE-2001-00353, to receive comments and requests for hearing on Delmarva's request. On August 17, 2001, the Staff filed a response to Delmarva's request. In its response, the Staff noted that the FERC had issued an order on July 12, 2001, provisionally granting RTO status to PJM. The Staff commented that the FERC had strongly encouraged the formation of one Northeast RTO encompassing PJM, the New York Independent System Operator, and ISO New England.[35] The SCC Staff observed that the FERC's Order raised the possibility that PJM's configuration could change if a larger Northeastern RTO developed as a result of the involuntary mediation process the Commission had initiated. The Staff, therefore, recommended that the SCC either delay acting on, or grant only interim approval of,

[34] See http://www.state.va.us/scc/caseinfo/pue/e00286.htm

[35] PJM Interconnection, L.L.C., Allegheny Electric Cooperative, Inc., Atlantic City Electric Company, Baltimore Gas & Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric & Gas Company, UGI Utilities, Inc., Order Provisionally Granting RTO Status, Docket No. RT01-2-000, 96 F.E.R.C. ¶ 61,061 at 61,231-61,232 (July 12, 2001).

Delmarva's request until more was known about the mediation process and about any Northeastern RTO that might be formed.

The Commission entered a second order on May 9, 2002, establishing a procedural schedule and requiring the filing of supplemental documents in this docket. The May 9, 2002 Order observed that a number of developments could have affected the accuracy and completeness of the information accompanying Delmarva's original request. It therefore required Delmarva to file on or before June 18, 2002, complete information about further developments relevant to Delmarva's October 16, 2000 request. Additionally, the Commission directed its Staff to file a supplemental report detailing the further results of Staff's investigation, and invited Delmarva and any interested person to file on or before August 2, 2002, comments responsive to the Staff's supplemental report.

On June 18, 2002, Delmarva filed its response to the SCC's May 9, 2002 Order. In its response, Delmarva reported that there had been no changes in Delmarva's status as a member of PJM, and that none of the features of PJM essential to Delmarva's compliance with Virginia's requirements had changed since August 31, 2001, or since Delmarva filed its Request on October 16, 2000.

On July 12, 2002, the Staff filed a supplemental report and recommended that the SCC delay or grant only conditional approval of Delmarva's request until more was known about the proposal for potential expansion of PJM West, Dominion's PJM South proposal, and the outcome of PJM's and MISO's discussions regarding formation of a single energy market across the PJM and Midwest regions.

On May 30, 2003, the Commission issued an order requiring Delmarva to develop and file a study of the costs, benefits, and resulting cash flows that would rise from the transfer of

Delmarva's transmission assets to PJM within 90 days of FERC's adoption of a final rule pertaining to SMD.

In light of the uncertain prospects for any final SMD rule, the Commission in an Order on March 4, 2004, directed Delmarva to first supplement its filing with a legal memorandum responding to the initial question whether, given Delmarva's long-standing membership in PJM, the Commission has authority under § 56-579 of the Act to grant "prior approval" to a transfer that appears to have occurred well before the enactment of this statute.

On March 26, 2004, Delmarva filed its Response. Delmarva asserted that on July 1, 1999, the effective date of the Act, it had already transferred "the management and control of its transmission system" in the Commonwealth to the PJM Interconnection, L.L.C., and that this transfer had occurred on March 31, 1997. Thus, the Company contended, that because it retained no management or control over its transmission system, there was nothing to which the Commission could give "prior approval" as envisioned by §56-579 of the Act. The Company further argued that Virginia law made clear that newly enacted statutes, such as the Act, could only be given prospective effect and could not be applied retroactively, unless the legislation clearly expressed the intent that it be applied retroactively, or if the legislation affected only procedural and not contractual or other substantive rights.

On April 14 and 16, 2004, respectively, the Staff and the Office of the Attorney General's Division of Consumer Counsel ("Attorney General") filed Responses to Delmarva's filing. All filing parties conclude that the Commission cannot apply its new authority under code § 56-579 to Delmarva's membership in PJM, which occurred prior to the passage of the statute.

The Commission found that Delmarva does not now possess, nor did possess as of July 1, 1999, management and control of its transmission facilities within the Commonwealth of

Virginia; that the management and control of such facilities is now, and has since at least March 31, 1997, been possessed by PJM; that the Commission was without authority to give "prior approval" to the transfer of management and control that occurred over two years prior to the passage of the Act, which directs all jurisdictional utilities to make such transfers subject to the prior approval of the Commission; that, notwithstanding the Commission's lack of jurisdiction under the limited factual circumstances presented herein, Delmarva's membership in PJM appears to satisfy the requirements of our RTE Rules and is not contrary to the public interest; and that this matter should accordingly be dismissed. The Commission rejected Delmarva's contention that its transmission facilities do not fall within the general jurisdiction of the Act, due to their geographical location on the Eastern Shore. To the contrary, we find that those facilities do comprise a part of "Commonwealth's interconnected grid and we retain jurisdiction over any subsequent transfer of operation and control of them by Delmarva or any other operator.

Dominion Virginia Power

On June 27, 2003, DVP filed an application seeking to join PJM. On September 26, 2003, the Commission entered its Order for Notice in this proceeding.[36] The Order for Notice directed the Company, among other things, to file certain relevant information and supporting information by November 26, 2003. This date was subsequently amended by additional Orders of the Commission to March 15, 2004.

The Commission issued a procedural schedule setting this matter for notice and hearing on (date). Respondents were directed to file testimony and exhibits by July, 15, and Staff was directed to file testimony and exhibits by August 16, 2004. The public hearing is scheduled for October 12, 2004

Kentucky Utilities

Kentucky Utilities' application to transfer control of its transmission facilities to the MISO is pending. HB 2637 suspended the applicability of the Restructuring Act to Old Dominion. The implication of this exemption coupled with the fact that the Company has joined MISO must be explored in terms of required Commission approval. More specifically, the issue HB 2637 places before the Commission is whether the Commission has authority to continue its review (post July 1, 2003) of Old Dominion's RTE application.

FERC Fact Finding Investigation

On May 12, 2003, the FERC established a fact finding proceeding (to be facilitated by an Administrative Law Judge) concerning congestion on the Delmarva Peninsula. The purpose of this proceeding is to evaluate the "extent and costs of transmission congestion" and to help identify potential solutions. The FERC fact finding was unusually structured as a "non-adversarial" proceeding with limited discovery and a hearing where only predetermined questions were asked with no opportunity for follow-up. The Virginia, Delaware, and Maryland Commissions were invited to join other interested parties and to send expert staff members and an ALJ to work with FERC's ALJ. The Commission filed a notice of intervention on May 19, 2003. The Commission Staff actively participated in this matter. Additionally, the Commission was represented at the "non-adversarial" hearing held on July 30-31, and on August 1 and 4, 2003.

The Commission filed a report to be appended to the FERC ALJ's report on August 11, 2003. The Commission's report expressed concern that the limited nature of the FERC's "non-

[36] See http://www.state.va.us/scc/caseinfo/pue/e00551.htm

adversarial" proceeding did not allow a sufficient exploration of certain issues and recommended that the entire matter should now be referred to the FERC's Office of Market Oversight and Investigations for a full enforcement investigation. The Delaware Public Service Commission also filed a report stating similar concerns and recommending that the FERC conduct a distinct proceeding to solve the Delmarva Peninsula's problems. The ALJ issued her report on August 12, 2003, finding that the record in the proceeding was sufficient to provide the FERC "with relevant and material information necessary to address the facts and determine possible solutions regarding congestion on the Delmarva Peninsula."

On September 9, 2003, the FERC issued an order in Docket No. PA03-12 directing the ALJ to make findings of fact and recommendations, primarily regarding solutions to congestion and lessons to be learned from the Delmarva experience. On September 11, 2003, the ALJ issued an order offering parties an opportunity to submit proposed findings of fact and recommendations, based on the record already developed in the proceeding by September 25, 2003. On September 24, 2003, the Commission filed a motion for rehearing arguing that the record in the proceeding was not sufficient for the development of findings of fact. No ruling was made on this motion.

The ALJ issued her Findings of Fact and Recommendations on October 10, 2003. She found that adoption of LMP and inclusion of the 69 kV facilities in the LMP scheme did not cause or increase congestion. Additionally, she found that the record does not support a finding that the exercise of market power has caused or increased congestion on the Delmarva Peninsula. She does, however, recommend that FERC's Office of Market Oversight and Investigations ("OMOI") make an independent review of the subject record to determine whether a further investigation into the existence and extent of market power should be undertaken.

On October 27, 2003, the Commission filed comments on the ALJ's report recommending that the FERC not adopt the proposed findings. Instead, the Commission urged the FERC to direct its OMOI to investigate the possible exercise of market power on the Delmarva Peninsula, and in so doing to: (a) interview all participants in the Peninsula wholesale power markets; (b) obtain all data OMOI deems relevant, under confidentiality provisions, if necessary; (c) involve the staffs of the three affected state commissions (Delaware, Maryland and Virginia) in its investigation and, in particular, to share data, analysis and preliminary conclusions with the staff of those commissions, and (d) file a written public report with the Commission within 120 days. At its December 17, 2003, open meeting the FERC decided to take no action on this matter; consequently no order will be issued.

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. Accordingly, on January 15, 2004, the Commission issued an Order initiating an investigation of this matter (Case No. PUE-2004-00001), directing public notice, providing interested parties with an opportunity to submit comments and request a hearing, and directing the Staff to investigate and file a report with its findings and recommendations on this matter. Nine parties submitted comments; however, no party requested a hearing. None of the parties asserted that a sufficient level of competition exists such that the elimination of default service will not be contrary to the public interest; and, with one exception, all of the parties, as well as the Staff Report, advised against the elimination of or changes to default service at the current time.

On April 23, 2004, the Commission issued a Final Order in this proceeding 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 EURC in this 2004 annual report on the status of competition in Virginia.

Earnings of Virginia Investor-Owned Electric Utilities

Each 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 and 2002 earnings of each investor-owned electric utility based on Staff's review of the earnings test analysis included in each company's AIF. The earnings reflect bundled (generation, transmission and distribution) per books Virginia jurisdictional return on common equity earned on a regulatory basis.

	2001	2002
Dominion Virginia Power	9.80%	22.36%
AEP-Virginia	9.52%	12.79%
Potomac Edison	13.80%	15.12%
Delmarva	6.47%	*
Kentucky Utilities	10.76%	14.19%

* Staff report has not been completed.

Each of the above companies filed financial data for calendar year 2003 during the first half of 2004. Staff has not yet completed its review of the 2003 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.

	2003
Dominion Virginia Power	13.26%
AEP-Virginia	12.10%
Potomac Edison	10.03%
Delmarva	4.28%
Kentucky Utilities	11.81%

Stranded Costs

On January 27, 2003, the EURC 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 underrecovery of just and reasonable net stranded costs. On March 3, 2003, the Commission entered an Order Establishing Proceeding, docketing Case No. PUE-2003-00062[37] 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 EURC.

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 Virginia Power, and the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates (the "Committees"), each presented one methodology. Staff's primary methodology proposed to calculate just and reasonable net stranded costs based on an asset valuation methodology and to calculate stranded recoveries from capped rates and wires charges. The Staff offered a second, alternative proposal, referred to as the Accounting Approach, that (1) measures recoveries of stranded costs from capped rates and wires charges, (2) measures potential stranded costs on an annual historic basis[38], and (3) after July 1, 2007 could be used to calculate actual stranded costs or benefits on an annual historic basis. Dominion Virginia Power's proposal provided for the monitoring of just and reasonable net stranded costs which included reporting to the EURC, (1) the over- or under-recovery of stranded costs collected through the wires charges from switching customers, (2) actual "above-market" or "potential" stranded costs exposure under

[37] See http://www.state.va.us/scc/caseinfo/pue/e030062.htm

[38] Potential stranded costs are defined as annual stranded cost exposure during the capped rate period, assuming all customers are paying market rates for generation service. This amount is a recalculation of capped rates based on the current embedded cost of generation by customer class compared to the actual market rate for the same period. The difference would be multiplied by the total kWh sales to determine the potential stranded costs. In its report, Staff proposed making this calculation annually on a historic basis during the transition period.

capped rates, (3) the amounts expended from funds available under capped rates to mitigate potential stranded costs, and (4) additional expenditures that negatively impact (increase) such costs during the transition period. The Committees' proposal was based on an asset valuation methodology for measuring stranded costs and incorporated stranded cost recoveries from both wires charges and capped rates.

The EURC'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 EURC because no consensus methodology was reached by the work group.

After several stakeholder meetings the EURC, on January 15, 2004, adopted a draft resolution (the "2004 Resolution") presented by the Division of Consumer Counsel of the Office of the Attorney General (the "OAG"). 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 similar to that provided for in the Accounting Approach outlined above. A portion of the data to be included in the annual September reports will be obtained from information filed with the Commission. Staff has met with the OAG several times and is currently working to provide the OAG with the necessary information to make its report to the EURC. Specifically, Staff will quantify earnings available for stranded costs recoveries for each electric utility for calendar years 2001, 2002, and 2003, at various target returns defined by the OAG. Staff will also calculate generation revenues based on each utility's embedded cost of providing generation service at various target returns for calendar year 2003. The OAG has requested calendar year 2003 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 will be compared to the cost-based generation revenues calculated by Staff to determine potential stranded costs for calendar year 2003.

Financial Profile of Virginia's Electric Utilities

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

The key trend in 2004 has been the dramatic slowdown of credit rating downgrades relative to the past quarter and the past two years[39]. From the quarter a year earlier, the number of downgrades dropped from 50 downgrades to 17, a dramatic 66 percent slowdown. The overall ratings distribution has remained close to the profile of the past two years with the number of negative outlooks dominating over positive ones. Debt financed expansion into non-regulated businesses such as merchant generation and energy marketing and trading continues to damage the consolidated financial profiles of utility holding companies. Other contributors

[39] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; April 30, 2004.

to the high number of negative outlooks have been weak competitive positionings, refinancing risks, investments in unregulated activities, volatility in wholesale power markets, and acquisitions of financially weaker companies.[40]

Similar to last year when two investor-owned utilities operating in Virginia were downgraded, Virginia has again been affected by the turmoil facing the energy markets. This year, another two Virginia utilities have had their ratings downgraded to BBB ratings from S&P (see Senior Secured Debt Credit Ratings and Outlooks table below). In one instance the lower ratings can be partly attributed to S&P's consolidated ratings methodology that rates legal subsidiaries on par with their corporate parents. The idea is that cash is fungible and therefore can be used anywhere within the corporate family to meet debt service obligations. As a result, a strong utility owned by a weaker parent generally is rated no higher than the parent or the consolidated corporate credit quality.

In response to the balance sheet damage and liquidity crisis over the last several years in the electric industry, a theme of "back-to-basics" is becoming increasingly prevalent. The industry's repair job involves disposing of non-regulated assets, cutting capital expenditures, de-leveraging balance sheets, negotiating interim re-financings and "state regulatory commissions asserting themselves more vigorously regarding the operations and finances of U.S. electric utilities in the years to come." The fact that, "so few downgrades occurred because of weakened credit profiles of utilities themselves is attributable in no small measure to the support provided by state commissions in recent years."[41]

The outlook for the competitive segments of the industry will continue to be bleak as a result of natural gas prices remaining high and capacity overbuild.[42] S&P states that after years

[40] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; April 30, 2004.
[41] Standard and Poor's Research: Regulated Operations Back in Fashion for U.S. Electric Utilities; June 19, 2003.
[42] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; April 30, 2004.

of rate freezes imposed by deregulation, the influence of state regulators will play a substantial role in the credit quality of regulated utilities. Standard & Poor's will follow rate case proceedings in Pennsylvania and Ohio paying particular attention upon levels of ROE allowed.[43]

Financial flexibility has always been important to electric utilities and an industry that is restructuring needs the regulatory and political stability to attract capital from both lenders and investors. Adequate capital structures are becoming not only more costly and difficult to build but more important to maintain. Credit downgrades force companies into making hard decisions about capital structures and operations.[44]

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

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

[43] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; April 30, 2004.
[44] Standard and Poor's Project Finance and Infrastructure Finance; October 2002.

Appalachian Power (AEP-VA) – The rating of BBB for AEP-VA has remained unchanged from the last report. S&P cites liquidity and balance sheet improvements such as $2 billion in refinancing and AEP's issuing over $1 billion in equity, although the enhancements were insufficient to support a BBB+ rating. Consistency in AEP's regulated strategy could lead to ratings improvement over time.

Delmarva Power - S&P rates Delmarva based on the consolidated credit quality of its corporate parents, Conectiv and PEPCO Holdings, Incorporated (PHI). S&P listed Delmarva on Credit Watch on July 15, 2003. This listing resulted from a bankruptcy filing made by Mirant Corporation and the uncertain effects upon shared power purchase contracts between Mirant, and Delmarva's parent company, PHI. On March 4, 2004, S&P revised Delmarva's outlook to negative from stable. This outlook downgrade was issued to reflect declining free cash flow estimates in other PHI affiliated companies and the belief that estimated cash returns from unregulated operations would not occur as forecasted. According to S&P, Delmarva's strengths include its low-risk distribution business, a high percentage of residential customers and a strong service territory economy. S&P considers transmission and distribution to have lower technical and operational risk than generation, and residential customers to be a very stable revenue source.

Kentucky Utilities - Kentucky Utilities' (KU) rating is based partly on its direct parent, LG&E Energy Corp., and its ultimate parent E.ON AG, a German utility conglomerate. On August 4, 2003, S&P revised the corporate credit ratings on LG&E and its subsidiaries to BBB+ from A-. This rating downgrade was made to reflect LG&E's weaker consolidated financial projections relative to prior expectations held by Standard & Poor's, and to a lesser extent, moderate credit deterioration at LG&E Energy's parent, E.ON AG. According to S&P, KU's current stable outlook is based on E.ON's commitment to support LG&E Energy and its affiliates. Future concerns are potential environmental expenditures related to KU's coal-fired facilities and KU's large industrial customer base, according to S&P.

ODEC - 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. Recently, S&P lowered ODEC's rating from A+ to A with a stable outlook. According to S&P, the ratings downgrade on ODEC does not result from any one development, but rather reflects an amalgam of risks raised individually in the past and a re-assessment of those risks in the context of ODEC's business profile. The stable outlook reflects S&P's expectation that ODEC will maintain its strong business position by averting meaningful customer losses, successfully completing the construction of the remaining peaking facility, and preserving wholesale costs at about current levels.

Potomac Edison – S&P rates Potomac Edison based on the consolidated credit quality of its parent company, Allegheny Energy, Inc. The ratings of Allegheny Energy, Inc. were lowered several times in the past three years, mirroring its debt-financed growth in the merchant and trading business, according to S&P. However, recent signs of improved financial performance prompted S&P to raise Allegheny Energy's credit rating to 'B+' from 'B'. The weak profile for Potomac Edison is due to its parent company's heavy debt burden and non-performing assets belonging to another subsidiary. Although Potomac Edison's stand-alone credit profile is stronger than that of its parent, Allegheny, it is also negatively affected by several of its own factors. These factors include a considerable concentration in industrial demand (40%), a reliance on a financially distressed affiliate to serve its provider-of-last-resort load, and a limited ability to recover unexpected cost increases due to a retail rate freeze in Maryland. On August 20, 2004, Standard & Poor's improved the outlook for Allegheny and its subsidiaries to positive from stable. The revised outlook was a result of S&P's expectation that

Allegheny will continue to pay down $1.5 billion or more of debt before the end of 2005. Further ratings upgrades could result from improved asset management, further debt reductions, or positive rate filing outcomes.

Dominion Virginia Power - DVP is the only investor-owned electric utility in Virginia whose ratings are not equalized with its corporate parent by S&P. DVP's rating is assigned on a stand-alone basis a corporate credit rating of A-. DVP's parent, Dominion Resources, Inc. is currently rated the lower score of BBB+ by S&P. According to S&P, DVP's higher rating is supported by adequate credit protection measures along with statutory insulation that restrains Virginia Power from subsidizing holding-company expansion into non-regulated activities.[45] S&P further states, "State statutes also empower Virginia's utility regulatory body, the State Corporation Commission, to proactively prevent the utility from paying dividends to the parent if that action would impair the utility or the parent would profit to the detriment of the utility's bondholders."[46] The rating agency added that DVP's rating also reflects its "relatively strong" economic service territory.[47]

Moody's favorably views the "go slow" approach of Virginia to energy deregulation and the three major effects from recently passed legislation, Senate Bill 651. These effects included extending the base rate freeze an additional 3.5 years until December, 2010, maintaining the July 2007 expiration of the "wires charges," and the removal of the fuel factor from a regulatory environment to a semi-competitive environment.[48]

Property Value Assessment

[45] Standard and Poor's Ratings Direct Research; Summary: Virginia Electric & Power Co.; May 26, 2004.
[46] Standard and Poor's Ratings Direct Research; Summary: Virginia Electric & Power Co.; May 26, 2004.
[47] Standard and Poor's Ratings Direct Research; Summary: Virginia Electric & Power Co.; May 26, 2004.
[48] Moody's Investors Service, Global Credit Research; Analysis: Dominion Resources Inc., June 2004.

For many years, the State Corporation Commission has assessed the value of the property of public service corporations providing light and power by means of electricity. As provided by Chapter 26 (§ 58.1-2600 et seq.) of Title 58.1 of the Code of Virginia, the Commission assesses the value of the property subject to local taxation and reports these values to the counties and cities for application of the appropriate tax rates, billing the corporations, and collecting taxes. With minor exceptions, the localities have been required by statute since 1966 to apply the real estate rate to all property assessed by the Commission. The Restructuring Act extended central assessment of the value of property to "electric suppliers" which includes independent power producers, merchant plants, and qualifying facilities. The Commission began assessing the electric supplier's property for the 2002 tax year.

The Commission assesses all real and tangible personal property at fair market value as prescribed in Article X, § 2 of the Constitution of Virginia. The same assessment methodology has been applied uniformly to electric suppliers and the public service corporations (the investor-owned utilities and electric cooperatives). The Commission interpreted the 1999 legislation as an expression of the legislative intent that the property of all generators of electricity be assessed using the same methodology.

According to testimony and exhibits presented in several Commission proceedings and information provided informally by electric suppliers, the property taxes paid by many of the independent power producers, merchant plants, and qualifying facilities (usually cogeneration facilities) have increased. In some instances, the increase in taxes has been significant. Testimony and exhibits presented in several Commission proceedings and information provided informally by electric suppliers indicate that some increases in tax bills can be attributed to the loss of special treatment given facilities to entice them to the locality.

In some cases, the value of these facilities was assessed at a fraction of original cost which resulted in lower taxes.

When the legislation providing for central assessment by the Commission was drafted, the General Assembly anticipated that taxes could increase due to a change in the assessment methodology. As a result, language was added to § 58.1-2606C of the Code which gives the localities flexibility to adopt a tax rate for electric generation equipment that is less than the real estate rate. The Commission staff understood this option was offered in an attempt to make the transition to central assessment for all electric generation as revenue neutral as possible.

In testimony in Commission proceedings and in informal discussions, electric suppliers have stated that the localities have been unwilling to adjust the real estate rate downward. According to their applications, testimony, and exhibits, the increase in taxes and the absence of tax relief in the form of a lower rate on generation property as prescribed in § 58.1-2606 C has led electric suppliers to apply to the Commission for review and correction of its assessments of the value of property. As of January 1, 2004, seven applications for review and correction were filed by six electric suppliers. Four suppliers have moved for leave to withdraw their applications, and those requests are pending before the Commission or a hearing examiner. Two applications are in pre-hearing stages. One application has been heard, and the presiding hearing examiner has filed his report. On June 11, 2004, Hearing Examiner Howard P. Anderson filed his Report on the application of Gordonsville Energy, L.P, in Commission Case No. PST-2002-00046. Examiner Anderson concluded that Gordonsville Energy had not established that the assessment of the value of its property for tax year 2002 was in excess of fair market value. The Commission has not taken final action on the report.

Retail Access Pilot Programs

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

The three Pilots consist of: (i) a Municipal Aggregation Pilot, in which one or more localities may aggregate its residential and small commercial customers utilizing an opt-in method[49] and one or more localities may aggregate its residential and small commercial customers utilizing an opt-out[50] method for the purpose of soliciting bids from CSPs for electricity supply service; (ii) a Competitive Bid Supply Service Pilot,[51] 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 demand equal to or greater than 500 kW.

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

> The Commission may conduct pilot programs encompassing retail customer choice of electricity energy suppliers for each incumbent electric utility that has not transferred functional control of its transmission facilities to a regional transmission entity prior to January 1, 2003. Upon application of an incumbent electric utility, the Commission may establish opt-in and opt-out municipal aggregation pilots and any other pilot programs the Commission deems to be in

[49] The opt-in method requires that a consumer affirmatively choose to participate.
[50] The opt-out method requires that a consumer affirmatively choose not to participate; absent such a decision the consumer will be included.
[51] 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.

> the public interest, and the Commission shall report to the Commission on Electric Utility Restructuring on the status of such pilots by November of each year through 2006.

On September 10, 2003, the Commission issued its Final Order approving the Pilots stating that, "the Pilots are in the public interest and further the goal of advancing competition in the Commonwealth." In its Final Order, the Commission approved DVP's application with certain revisions including: (i) an opportunity for mid-sized commercial customers to participate in either the CBS Pilot or the Commercial and Industrial Pilot; (ii) a requirement that the Company initiate notification to customers randomly selected to participate in the CBS Pilot; and (iii) a "hold harmless" provision in the CBS Pilot that states participants randomly selected shall pay no more than they otherwise would have under capped rate service.

On October 27, 2003, DVP issued a Request for Qualifications to CSPs that may be interested in participating in the CBS Pilot. Only those CSPs that respond to the Request for Qualification are then eligible to bid on blocks of customers in the CBS Pilot. On November 14, 2003, three CSPs, Washington Gas Energy Services, Pepco Energy Services, and DVP's affiliate Dominion Retail, responded indicating that they were interested in participating. Simultaneously, the Company began soliciting municipalities to participate in the Municipal Aggregation Pilot. Several indicated some level of interest and agreed to allow the Company to fund a feasibility study to be conducted by a third party.

On December 11, 2003, DVP filed a request for three revisions to the Pilots. Specifically, DVP requested to: (i) delay the issuance of the Request for Bids in the CBS Pilot until ten days after the acceptance of the Company's market price/wires charge compliance filing for 2004; (ii) apply the 50 percent wires charge reduction to each competitive wires charge component rather than to the total wires charge; and (iii) reduce the time period for the Commission Staff to select the winning CSP in the CBS Pilot from ten days to two days.

On January 9, 2004, the Commission issued an Order Approving Pilot Revisions. In the Order the Commission granted approval for the first two revisions as no one opposed them. With respect to the third proposed revision, the Commission agreed with the Division of Consumer Counsel, Office of the Attorney General and the Commission Staff that reducing the time period for the Commission Staff to select the winning CSP may not allow the Staff to perform a thorough evaluation. However, the Commission recognized that a shorter selection period may be desirable for CSPs and as a result revised the CBS Pilot terms and conditions to state the Commission Staff must select the winning CSP within ten days, or sooner if practicable.

On January 12, 2004, DVP issued the Request for Bids to the three prequalified CSP. Bids were due by noon on February 3, 2004. No CSPs submitted a bid. While CSPs were not required to indicate why they did not submit a bid, Pepco Energy Services sent a letter to DVP with a copy to the Commission Staff stating, "PES has carefully reviewed the cost to serve participating customers in the Pilot Program and it has determined that it is not feasible for PES to submit a proposal whereby resulting in savings."

As a result of the failure of the Pilots to attract CSP participation, on January 30, 2004, DVP filed a request to delay the start date of the Pilots for two months while it considered modifications. On February 23, 2004, the Commission granted the extension and required the Company to notify all Pilot volunteers of the delay and to file its proposed modification by April 2, 2004.

The Company filed its proposed modifications, as ordered, on April 2, 2004. The Company proposed numerous modifications with the key component of the modifications a 100% wires charge reduction for 2004. For years after 2004, the wires charge reduction would be an amount up to but not exceeding the reduction for 2004. Pilot customers therefore would only pay, in later years, the increment that the later years' wires charges exceed the 2004 wires charges. Other proposed modifications included: (i) dividing the ten-day period for the Commission Staff to select the winning CSP into two components with the first a two-day period to select the winner based on price and the second an eight-day period to perform due diligence on the qualifications of the CSP; (ii) allowing the Commission Staff to select one CSP to serve all three geographic blocks in the CBS Pilot (originally one CSP could serve no more than two blocks) if selection of another CSP would result in an offer price of at least 1.5 percent higher than the lowest offer price; and (iii) specifying that the first bid supply period would extend through January 2006 and the second bid supply period would extend to July 2007.

The Commission received comments from Constellation NewEnergy, Inc., Direct Energy Marketing, Inc., Dominion Retail, Inc., Pepco Energy Services, Inc., Strategic Energy, LLC, Washington Gas Energy Services, Inc., Urchie B. Ellis, the Division of Consumer Counsel, Office of the Attorney General and the Commission Staff. Most of the comments were generally supportive of the Company's modifications although some additional revisions were suggested. Several of the comments, including those of the Consumer Counsel, indicated that the Company should eliminate the wires charge for the duration of the Pilots. The Commission Staff indicated that it encouraged the Company to eliminate the wires charge reduction for the length of the Pilot, but did not believe the Commission could require the Company to forgo its statutorily allowed right to the wires charge. The Company asserted in its response to the comments that it would not agree to eliminate the wires charge for the duration of the Pilots, and further stated that it believed its proposal was sufficient to attract CSPs to participate.

On May 25, 2004, the Commission issued an Order Approving Revisions. The approved revisions included the followings: (i) the wires charge reduction will be calculated as proposed by the Company; (ii) the Commission Staff will select the winning CSP in the CBS Pilot within two days; however, in the event that the Commission Staff cannot select the winning CSP within two days, then the winning CSP will be given the opportunity to withdraw its bid (this was a compromise to accommodate the CSPs' request for a shorter selection period); and (iii) the Commission Staff may select one CSP to serve all blocks in the CBS Pilot.

With the Commissions May 25, 2004, Order Approving Revisions, the three Pilots have now been re-initiated. On June 22, 2004, DVP issued a new Request for Qualifications in the CBS Pilot with Responses due by August 23, 2004. On August 24, 2004, the Company will issue a Request for Bids to those CSPs that respond, and bids will be due by noon on September 14, 2004. With respect to the other two Pilots, no CSPs have enrolled any C & I customers and no municipality has indicated definitive interest in participating in the Municipal Aggregation Pilot.

Future SCC Activity

As described in this Report, the basic rules, systems, and procedures are in place to accommodate retail choice. 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:

- Analyze the technical and operational implications of the RTO filings and act upon pending applications.
- Continue to explore the potential for designating alternative default service providers.
- Re-evaluate the method for determination of the market price and resulting wires charge for incumbent electric utilities, then re-set those numbers.

- Develop the methodology to determine market-based costs for use in exemption of wires charges and minimum stay provisions.
- Continue the development of a proper foundation for competition including the on-going work involving competitive metering, consolidated billing, development of business practices, distributed generation interconnection standards, and aggregation.
- Continue 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.
- Evaluate the merits of proposed pilot 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 July 1, 2004, WGL's program has twelve CSPs serving 7,155 non-residential customers and four active CSPs serving approximately 65,840 residential customers. Cumulatively, these accounts represent approximately 17.6 percent of the 416,001 natural gas customers in WGL's service territory. It is important to note, however, that WGL's unregulated affiliate, WGES, is serving approximately 79 percent of the non-residential shoppers and approximately 76 percent of residential shoppers. .

CGV's Retail Access Program

As of July 1, 2004, there are four CSPs providing service to 1,212 non-residential customers and 8,818 residential customers. Cumulatively, these accounts represent approximately 4.7 percent of the 212,746 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 the Report includes a discussion of comments advanced by various stakeholders as a means of facilitating effective competition in the Commonwealth and the SCC's continued actions to implement the elements of the Restructuring Act as soon as practicable.

To assist development of a comprehensive list of recommendations to foster effective competition, on April 26, 2004, the Staff sent a letter electronically to 81 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 eight responses, included as Appendix III-A to this Report. It should be noted that two of these responses were joint comments submitted on behalf of several parties, thus representing suggestions from a total of 15 entities. In a similar survey conducted in 2003, the SCC received twelve such responses.

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

Generally, most of the comments received are similar to those expressed in last year's report and reiterated during the past year via various forums. Respondents' recommendations, generally discussed below, do not provide new ideas as they have already been considered, or are currently under consideration, by the SCC and the EURC.

The majority of the respondents continue to believe that the major obstacles to effective competition in Virginia include the lack of a fully functional RTO and competitive markets, as well as legislative and regulatory uncertainty. Other major issues mentioned include the existence and method of determining wires charges, the recovery of yet-to-be-quantified stranded costs, and the existence of low, capped rates of the incumbent utilities.

Although, the majority of the responses identify the above concerns, these same entities encourage the continued path of restructuring and seek quick resolution to the perceived flaws. The other two responses representing consumer interests remain skeptical. The consumer groups appear to accept the path of continued restructuring, but at a more cautious approach and pace. They seek a slower pace aimed at a better balance of risks and benefits among LDCs, CSPs, and consumers. 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. The stakeholder recommendations included in this section are not new; they are similar to those expressed in prior reports.

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 it considers to be in the public interest. Passage of Senate Bill 651 of the 2004 General Assembly and approval by the Governor provides legislative direction to continue implementing the Restructuring Act. The SCC continues to perform its charge to provide regulatory certainty and put in place the necessary infrastructure to implement restructuring.

As previously discussed in the RTE Development portion of Part II of this Report, proceedings are currently underway regarding the transfer of transmission facilities of the incumbent investor-owned utilities to PJM prior to January 1, 2005. The final outcomes of such transfers are pending before this Commission.

While Virginia has traditionally enjoyed relatively low electricity prices, these low prices continue providing little margin for which alternative suppliers can compete. As was the comments last year, there is tension between believing that price caps are a fundamental flaw of the Restructuring Act and that of requiring consumers not be exposed to market-based prices until effective competition has developed and can be depended upon to regulate prices.

Related to the aforementioned issue, respondents continue to claim that the wires charge mechanism may be as strong a detriment to the development of competition as rate caps. The incumbent utilities share a common view that the wires charge is designed to assure utilities of revenue neutrality during the transition period.

The 2004 General Assembly agreed that rate caps are an essential consumer protection built into the Act and determined to continue such protection by extending the capped non-fuel rates for incumbent utilities until December 31, 2010. It also determined that the wires charge would expire on July 1, 2007 as originally intended.

Additionally, provisions were included to permit a large customer's choice to be exempt from the current minimum stay provisions or the payment of wires charges in exchange to be charged market-based costs upon any subsequent return to supply service provided by the incumbent utility. The SCC has initiated a proceeding to establish any requirements to pursue such exemptions as discussed in Part II.

The elimination of the wires charge may help, but certainly will not guarantee, competition. Although there is no wires charge within the service areas of Delmarva, AEP, or Allegheny Power, there still is no shopping. However, as also discussed in Part II, the SCC has approved three pilot programs initiated by DVP to reduce the wires charge in hopes of inducing competition.

Another issue related to those above regard the recovery of stranded costs. Generally, the incumbent utilities believe the Restructuring Act simply requires any stranded costs that exist to be recovered through the utility's capped rates and wires charges without quantifying the amount of such stranded costs. Other respondents contend that one must quantify the total amount of stranded costs to determine an over or under recovery. The 2004 General Assembly charged the Office of Attorney General to oversee any pursuit of identifying and quantifying any stranded costs.

Many believe the underlying premise of the Restructuring Act is that a competitive market will result in lower retail electricity prices for Virginia consumers. Unfortunately, retail competitive activity continues to develop slowly throughout the nation, not just in Virginia or in the Mid-Atlantic region. Consequently, a market has not yet fully developed that can be depended upon to govern prices.

In summary, the status of competition is not encouraging. Though there are isolated instances in other jurisdictions of competitive activity among larger commercial and industrial customers, retail choice is not yet providing meaningful benefits or yielding sustained savings anywhere in the country.

In terms of the existence of retail competition, little, if anything, has changed since last year. There still appears to be universal agreement that before a viable competitive retail market develops in the Commonwealth there must be a robust wholesale market and an operational and independent regional transmission organization. While much work has been done or is in the process of being done, it will take more time before that foundation becomes a reality. 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.

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

Appendix III-A

RESPONSES FROM STAKEHOLDERS

September 1, 2004

APPENDIX III-A
RESPONSES FROM STAKEHOLDERS

CONTENTS

COMMONWEALTH OF VIRGINIA

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STATE CORPORATION COMMISSION
DIVISION OF ECONOMICS AND FINANCE

April 26, 2004

Dear Market Participant:

As directed by §56-596 B of the Virginia Electric Utility Restructuring Act, the State Corporation Commission is preparing its fourth annual report to the Commission on Electric Utility Restructuring ("EURC") and the Governor, to be filed by September 1, 2004. That report will cover three topics: 1) the status of the development of regional competitive markets, 2) the status of competition in the Commonwealth, and 3) recommendations to facilitate effective competition in the Commonwealth.

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

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

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

Please provide your comments to me by May 24, 2004. Such response may be sent as a hardcopy via mail or preferrably, electronically as an attached WORD Document at deichenlaub@scc.state.va.us. Such comments will be posted to our website at http://www.state.va.us/scc/division/eaf/comments.htm. Following such posting, any party may submit additional comments in reaction to those posted, if they so desire, by June 4, 2004. Both the initial set of comments and any supplemental comments will be attached as an appendix to the Commission's September 1st report.

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

Sincerely,

Dave Eichenlaub

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May 24, 2004

VIA EMAIL

David R. Eichenlaub
Assistant Director, Economics
Division of Economics and Finance
State Corporation Commission
1300 East Main Street, Fourth Floor
Richmond, Virginia 23218

Re: SCC Report of the Status of Competition in the Electric Industry

Dear Mr. Eichenlaub:

Thank you for your letter of April 26, 2004 seeking comments from stakeholders for the Commission's fourth annual report to the Commission on Electric Utility Restructuring ("EURC") and the Governor under the Virginia Electric Utility Restructuring Act. On behalf of Appalachian Power Company ("Appalachian" or "Company"), this letter will report Appalachian's brief comments in response to your invitation.

1. Status of Competition in the Commonwealth

As the Company has noted in past years, all of Appalachian's customers are eligible to choose an alternative generation supplier, and the Company stands ready to respond to customers' choices as alternative supply arrangements may become advantageous to them. Implementation of the requirements for customer choice are, for the most part, in place and in compliance with the Commission's retail choice rules. Customer switching of suppliers in the Company's service territory has not yet developed, however.

2. Status of Regional Competitive Markets

At least one major feature of the Restructuring Act remains to be implemented. The applications of the Company, and other utilities, to join regional transmission entities (RTE) have yet to be acted upon by the Commission. The broader access to regional markets made possible by the entry of utilities into RTEs is a necessary step toward completing implementation of the Restructuring Act and will further the development of regional competitive markets. As the Company urged last year, the Company's proposal to transfer operational and functional control of its transmission facilities to PJM Interconnection, LLC should be resolved promptly.

3. Recommendation

The expectations created by the Restructuring Act in 1999 were that retail competition would develop during a period of capped rates between January 1, 2002 and July 1, 2007. Significant competition has not occurred to date, however, more than halfway through that period. The General Assembly has addressed this lack of competitive activity by amending the Restructuring Act to extend capped rates until December 31, 2010. The provisions of the 2004 amendments to the Restructuring Act appear to be adequate at this juncture.

In addition to the entry of Virginia utilities into RTEs, stranded cost monitoring issues remain a subject of current concern. Several existing proposals with respect to stranded cost issues bear all the hallmarks of traditional public utility rate regulation. The Company opposes extensive stranded cost proceedings that would appear to be rate regulation by another name. Consideration of stranded cost monitoring should reflect the unique circumstances of each incumbent electric utility.

The entry of Virginia utilities into RTEs is the most critical issue faced by the Commission to further the expectations in the Restructuring Act. Appalachian recommends that the Commission give priority to the resolution of the RTE issue over other issues, including any stranded cost proceedings that may be undertaken in the next year.

Sincerely,

Barry L. Thomas
Director, Regulatory Services VA/TN

May 24, 2004

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

Dear Mr. Eichenlaub:

Dominion Virginia Power (the Company or Dominion) is pleased to respond to your April 26 request for comments and recommendations concerning the status of competition in Virginia, the development of regional markets, and steps that can be taken to facilitate effective competition in the Commonwealth. In this submission the Company will also offer comments on the state of Virginia's restructuring program and the benefits it has already produced for consumers. The annual reports required by Virginia Code § 56-596 provide a valuable opportunity for the Commission to keep the legislative and executive branches fully and fairly informed about important issues in Virginia's transition to a fully competitive market. The reports also offer valuable information to other stakeholders in the restructuring process. We appreciate the opportunity to submit input again to this year's report.

Our comments will include our perspective on the electric industry restructuring movement, both across the nation and in Virginia. We believe that there is strong evidence that the effort to restructure the industry and introduce competition in the supply of electricity continues to make progress and benefit customers.

The Company's comments will discuss the factors that we believe are necessary for the successful continuation of Virginia's restructuring program and the development of competitive retail electricity markets in the Commonwealth. For example, we believe timely approval by the Commission of the applications by Dominion and American Electric Power to join the PJM Interconnection LLC is a prerequisite for the development of competition in Virginia. Successful development of a competitive retail electricity market in the Commonwealth also requires a high degree of regulatory certainty. This is needed to reinforce the legislative certainty reaffirmed earlier this year by the General Assembly's passage of Senate Bill 651 amending the Virginia Electric Utility Restructuring Act.

Electric Industry Restructuring and Competition in 2004

Restructuring: The National Perspective

Currently, 18 jurisdictions (17 states and the District of Columbia) in the United States are pursuing restructuring of their electric industries. Like Virginia, nearly all of these jurisdictions have instituted a multi-year transition period to allow for market development. Capped or frozen rates have been standard features of these transition periods. Jurisdictions undertaking restructuring programs have generally abandoned traditional cost-of-service regulation for generation. Critics of this traditional system assert that this form of regulation fosters inefficiency, induces utilities to build new assets for the primary purpose of increasing the rate base, and leads to frequent rate increases.

Capped or frozen rates, often called standard offers, have produced sizable customer savings in most states, according to consumer advocates. Customer savings from capped rates have been the initial indicator of a successful restructuring program.

Savings from standard offers were largely responsible for the $3.8 billion in consumer savings cited by former Pennsylvania Governor Tom Ridge three years ago. More recently, Sonny Popowsky, consumer advocate for the state of Pennsylvania, also hailed customer benefits from the rate caps. "With rate caps in place, customers have not suffered as a result of the lack of robust retail competition," Popowsky told the Pennsylvania House Consumer Affairs Committee on March 4. "In real, inflation-adjusted terms...virtually all Pennsylvania consumers are paying lower rates today than they were in 1996."

Ohio consumers have also benefited from capped rates, according to former Ohio Consumers' Counsel Robert S. Tongren. In a January 2003 report, Tongren said Ohio consumers had saved over $250 million during the previous two years because of capped rates and a five percent generation discount that was also part of the state's restructuring plan.

In early 2003, the Public Utility Commission of Texas reported to the state legislature that "the Commission's estimates in this report show that retail customers have saved, at a minimum, over $1.5 billion in electricity costs during the first year of competition as compared to the regulated rates in effect during 2001."

The second indicator of successful restructuring, often coming several years into the transition to retail competition, is customer switching. Although the rate of customer switching to alternative suppliers is not as great as some observers had expected a few years ago, the restructuring movement continues to advance in many parts of the United States. The pro-competition Alliance for Retail Choice recently reported that the load served by competitive providers nationwide has tripled since mid-2001 and reached approximately 52,000 megawatts by the end of 2003. Customer switching has been particularly active in Pennsylvania, with more than 450,000 customers served by alternative providers as of April 1 of this year; Texas, with more than 900,000 customers served by alternative providers as of February 29; and Ohio, with almost 945,000 customers served by alternative providers as of December 31, 2003, according to figures compiled by the states' public utilities commissions. In Ohio, the overwhelming majority of the consumers served by competitive suppliers belong to aggregations run by groups of municipalities. The success of municipal aggregation in Ohio bodes well for its future in Virginia, especially since the 2004 General Assembly took strong steps to make it easier for cities and counties to form such buying groups.

According to data from state commissions, more than 25 percent of the total electric load is served by alternative providers in four jurisdictions: Maine, 38 percent; Texas, 36 percent; the District of Columbia, 36 percent; and Massachusetts, 29 percent.

Rate Increases in States Not Pursuing Restructuring

While capped or frozen rates have been standard features of the transition periods in states undertaking restructuring, there is a pronounced trend toward rate increases and rate increase petitions in states that are not pursuing restructuring or that have deferred their restructuring programs.

Rate increases approved so far during 2004 include the following:

State	Percentage increase granted
Indiana	8.4
Missouri	4.2
Wisconsin	4.7
Wyoming	7.2

Rate increases approved during 2003 include the following:

State	Percentage increase granted
Colorado	15.6
Iowa	3.0
Louisiana	8.5
New Mexico	4.0
South Carolina	5.8
Utah	7.0
Wisconsin (decisions for three utilities)	3.5, 9.1 and 11.8
Wyoming	2.8

Pending petitions for rate increases include the following:

State	Percentage increase proposed
Idaho (two utility petitions)	17.7 and 24.1
Iowa	16.3
Kentucky (two utility petitions)	8.5 and 11.3
Nevada (two utility petitions)	9.6 and 13.1
Washington	13.5

Source: Regulatory Research Associates

The cases cited above include both base and fuel rate increases. Under the Virginia Electric Utility Restructuring Act (the Restructuring Act), capped base rates have been imposed on incumbent utilities since 1999. Senate Bill 651, recently passed by the General Assembly and signed by the governor, freezes Dominion's fuel rate at its current level until July 1, 2007.

The respected trade journal *Public Utilities Fortnightly* has also warned of impending "sticker shock" due to utilities petitioning state utility commissions for the rate basing of billions of dollars of improvements, including new generation and environmental upgrades. *Public Utilities Fortnightly* estimated that utilities could petition to have as much as $5 billion in environmental equipment rate based, a move that would lead to higher rates in many areas. (Richard Stavros, "Sticker Shock," *Public Utilities Fortnightly*, April 2004, pages 4-5)

Restructuring Protects Virginia Consumers

In contrast, Virginia's restructuring program has produced unprecedented price stability for the Commonwealth's consumers. Senate Bill 651 amended the Restructuring Act and extended its capped rate period for an additional three-and-a-half years, through December 31, 2010. In many cases, base rates for Virginia's incumbent utilities are capped at or near levels set in the early 1990s. Base rates can be adjusted only in a limited number of circumstances set forth in the Restructuring Act.

A January 2004 study by the Richmond consulting firm of Chmura Economics & Analytics quantified savings from the capped rates for many Virginia consumers. The study commissioned by Dominion found that capped base rates would save the Company's residential customers as much as $1.8 billion through the end of 2010. Total savings during the extended 1998-2010 capped rate period would range from $789 to $966 per household, producing average annual savings of from $61 to $74, or up to 7.3 percent of the bill of the typical customer who uses 1,000 kilowatt-hours each month. The study also found that savings from the capped rates would produce about $307 million in additional economic activity in the Commonwealth.

Senate Bill 651: New Protection for Many Customers from Rising Fuel Prices

Senate Bill 651, in addition to extending the capped base rate period, provides new price protection for many Virginia electric consumers. The bill amends the Restructuring Act to freeze Dominion's fuel rate at its current level until July 1, 2007. At that point, the Commission can move the rate either up or down once, depending on expected fuel prices, with the new rate in force through the rest of the capped rate period.

This marks a profound shift of risk in the electric business. Historically, utilities have fully recovered their fuel costs from their customers. The responsibility for meeting rising fuel costs now shifts to the company. A report by Norwood Energy Consulting LLC found that fuel charges for Dominion customers would have likely increased by as much as 20 percent, or approximately $220 million, by 2007 if Senate Bill 651 had failed to pass. The report was commissioned by the Office of the Attorney General's Division of Consumer Counsel and was released on March 9.

Progress on Customer Choice in Virginia

The Commonwealth also continues to make progress toward the ultimate goal of the Restructuring Act: providing Virginia consumers with a wider choice of energy providers.

Dominion Virginia Power Retail Choice Pilot Programs

In September 2003, the Commission approved the Company's request to conduct three pilot programs to stimulate the development of a competitive electricity market in Virginia and bring the potential benefits of retail choice to a variety of customers. The programs focus on three aspects of retail choice:

- A Competitive Bid Supply Service pilot that will use a bidding process to match blocks of small commercial and residential customers with competitive suppliers. This pilot is expected to provide valuable experience for the provision of default service, defined by the Restructuring Act as service for customers who do not choose an alternative provider, cannot obtain service from one or whose alternative supplier fails to deliver service.

- Increasing mid and large-sized commercial and industrial customers' access to competitive power supplies.

- Forming buying groups, or "aggregations," administered by cities, counties and towns to secure lower prices on electricity for their citizens.

In all three cases, Dominion proposed a significant reduction of wires charges for pilot participants when a customer switches to an alternative supplier. This reduction is designed to give competitive suppliers more opportunity to make attractive offers to retail customers. As of May 20, approximately 89,000 customers had volunteered to participate.

On April 2, 2004, the Company asked the Commission to approve several modifications to the programs to help them move forward successfully. The proposed modifications include a larger wires charge reduction of up to 100 percent of the participant's wires charge for 2004. Other modifications include changes in the bidding process used to select competitive service providers (CSPs) to supply electricity to participants in the Competitive Bid Supply Service pilot. The Company's petition for pilot revisions is now pending before the Commission.

Additionally, to clear another barrier to the pilot programs moving forward successfully. the Company has asked the Federal Energy Regulatory Commission to approve its proposal for offering backup supply service to CSPs. This will allow the providers to continue serving their customers within Dominion's Virginia service area during supply interruptions. Such events could be caused by a number of factors, including emergencies or lack of capacity on other transmission systems. The Company will offer such service only until it is fully integrated into a regional transmission organization (RTO). At that point Dominion's backup supply service will no longer be needed.

The Company is encouraged by the interest shown in the pilots by customers, CSPs and municipalities. It will assist municipal governments interested in forming aggregation programs under the pilot with funding for a feasibility study. Municipalities agreeing to participate in the feasibility study include Charles City County, Chesterfield County, and the cities of Charlottesville, Fairfax and Hampton. Buckeye Energy, an Ohio energy consultant firm with extensive experience with municipal aggregation in its home state, has been retained to perform the study.

Dominion hopes the Commission will approve its proposed modifications to the programs so the pilot price-to-compare can be determined and the pilots can proceed in a timely and successful manner.

Progress toward Customer Choice through Senate Bill 651

Amendments made to the Restructuring Act through the passage of Senate Bill 651 should also greatly facilitate development of viable retail competition in the Commonwealth.

The extension of the capped rate period through December 31, 2010 will provide additional time for market development. During this transition period, customers will be free to buy power from competitive suppliers but will be able to return to the stability and safety of the "safe harbor" of capped rates if market prices rise or become volatile. In short, consumers will have the potential benefits of customer choice and also the stability and certainty of capped rates.

Significantly, the amendments approved by the 2004 General Assembly also reiterated the commitment made by the Restructuring Act in 1999 to end all wires charges on July 1, 2007.

Other amendments should make it easier for municipalities to form aggregations to secure energy for their citizens from CSPs. The amendments allow cities and counties to conduct aggregation programs on an "opt out" basis, in which citizens are automatically included unless they make an affirmative decision not to participate. Amendments to the Restructuring Act in 2003 already authorized opt-out municipal aggregation as part of pilot retail choice programs. Municipal aggregation has proven to be a very successful means of bringing the benefits of retail competition to large numbers of customers in other states. In Ohio, for example, approximately 869,000 customers participated in opt-out municipal aggregation programs as of December 2003.

Two changes to the Restructuring Act proposed by Senator Watkins and included in Senate Bill 651 will free many customers from wires charge and minimum stay obligations ahead of schedule. The first amendment will allow large commercial and industrial customers, as well as aggregated customers in all classes, to become exempt from wires charges if they agree to accept market based rates, instead of capped rates, should they return to their incumbent utilities. The wires charge exemption program will begin in each incumbent's service territory after the Commission has promulgated the necessary rules and regulations and the utility transfers management and control of its transmission assets to a RTO. In the case of the wires charge exemption, approximately 1,000 megawatts of Dominion's peak load will be able to escape wires charges during the first 18 months of the program. Thereafter, the Commission may issue regulations on how much load for each incumbent utility can be exempted from wires charges. The Company has already begun reviewing its policies and procedures for implementing this amendment and anticipates proposing a robust program that will be attractive to all classes of customers. We urge the Commission to take the steps necessary for this program to become effective. This includes timely approval of applications for RTO membership.

The second amendment will allow large commercial and industrial customers that switch to competitive providers to become exempt from minimum stay requirements if they agree to accept market-based rates if they return to service with their incumbents. Here again, the provision's effectiveness is contingent upon an incumbent's transfer of transmission management to a RTO. We also urge the Commission to act promptly and take the steps necessary for this provision to become effective, including timely approval of RTO membership, since the program cannot be implemented until Dominion has transferred management and control of transmission assets to an RTO.

Prerequisites for Successful Competition in Virginia

While Virginia's restructuring program has made great progress, the Company acknowledges that additional steps need to be taken for the development of robust, successful competition in the Commonwealth. These include a functioning RTO and continued legislative certainty, along with a high degree of regulatory certainty, regarding the future of Virginia's restructuring program.

- ***Necessity of a Functioning RTO***

The transmission systems owned by Virginia's incumbent utilities must be integrated into a functioning RTO before a competitive retail market can develop. Stakeholders in the restructuring process have repeatedly labeled the lack of a functioning RTO in the Commonwealth as the single greatest barrier to retail competition development and a significant barrier to wholesale competition.

In comments submitted to the Commission for its 2003 status report on competition, stakeholders made the following statements regarding the role a functioning RTO must play in successful competition, both wholesale and retail.

"A robust energy market for Virginia's consumers is highly dependent upon transmission assets being placed under the control of a Independent System Operator, or a Regional Transmission Organization (RTO)." – Strategic Energy

"VEPA continues to observe that the most significant obstacle to the development of robust competition in Virginia is the delay of Virginia's incumbent electric utilities in gaining state approval to join an approved Regional Transmission Organization (RTO) to serve wholesale markets, ultimately to the benefit of retail customers." – Virginia Energy Providers Association

"A RTO operated transmission network facilitates the movement of bulk power transactions to ensure reliability, economic efficiency and market liquidity." – National Energy Marketers Association

In the 2003 report, the Commission itself made the following observation: "Perhaps the most common issue raised among the comments submitted in response to the Staff's letter regards the lack of a fully functional RTO as the major obstacle" to active competition.

General Assembly Policy Commitments to RTOs

The General Assembly has consistently recognized that a properly functioning wholesale electricity market is vital to the development of effective retail competition. In order to facilitate development of a fair and open wholesale market in Virginia, the Restructuring Act as enacted in 1999 required incumbent utilities to join or form regional transmission entities, conditioned upon Commission approval. In 2003, enactment of House Bill 2453 reaffirmed the Assembly's commitment to regional transmission organizations. This bill amended the Restructuring Act to require incumbents to enter regional transmission organizations by January 1, 2005, subject to Commission approval. It further required applicants to include comparative cost-benefit studies of RTO membership and its economic impact on consumers.

Since passage of the Restructuring Act in 1999, Dominion has actively pursued RTO membership, initially through the formation of the Alliance RTO and currently through its efforts to join PJM in the timeframe set forth in the Restructuring Act.

In its application to integrate into PJM, filed with the Commission on June 27, 2003, Dominion submitted testimony to show that PJM will provide Dominion's consumers with enhanced reliability, optimized system planning and improved resource adequacy. These reliability benefits cannot be fully measured quantitatively, but their importance cannot be overstated. The Northeast blackout of August 14, 2003 reinforces the need for system operators to be able to monitor across regions and react in real time to prevent the occurrence and spread of outages. In addition, the August 14 blackout affirms the need for optimized system planning to ensure that proper infrastructure investment is made to meet the needs of the economy. Integration of Virginia's incumbent utilities into PJM provides the best means to accomplish these objectives.

In accordance with the Restructuring Act amendments of 2003, Dominion retained Charles River Associates to conduct a cost-benefit analysis of PJM membership and shared this analysis with the Commission in its application. This cost-benefit study affirmed the importance of the qualitative benefits described above, describing significant benefits of PJM integration, including enhanced reliability, optimized system planning and improved resource adequacy. In addition, the cost-benefit analysis measured energy and capacity savings of approximately $470 million for Dominion retail customers over the ten-year study period, net of PJM costs paid by those consumers.

The full quantitative and qualitative consumer benefits that have been presented in Dominion's application, including its cost-benefit study, are dependent upon integration of both American Electric Power (AEP) and Dominion into PJM. The benefits of competition that the Restructuring Act envisions can best be delivered if all incumbent utilities in the Commonwealth are integrated into PJM.

Dominion has complied with the Restructuring Act (as amended) and with the Commission's orders to complete its filing. Participation of Virginia's incumbent utilities in an RTO is essential for development of an active retail market and provides enhanced reliability and savings for consumers.

The Commission has issued a procedural order setting starting dates for hearings on July 27 for AEP and October 12 for Dominion. To ensure timely development of retail competition it is imperative that the Commission complete its review and approve the pending applications of Dominion and AEP to allow integration into PJM in compliance with the January 1, 2005 date in the Restructuring Act.

- ***Legislative and Regulatory Certainty Necessary for Restructuring's Success***

Continued legislative certainty and a high degree of regulatory certainty are another prerequisite for the successful development of competition in Virginia. The passage of Senate Bill 651 by the 2004 General Assembly and its subsequent signing by Governor Warner reaffirmed Virginia's commitment to the restructuring process, as did the General Assembly's rejection of efforts to suspend the Restructuring Act. Passage of Senate Bill 651 marked a clear legislative policy decision to continue the Commonwealth's restructuring program. Prospective competitive service providers and independent power producers interested in Virginia but previously uncertain about its commitment to a competitive market now have the certainty they need to develop solid business plans for entry into the state. Those already doing business here do not have to constantly re-evaluate their decisions to come to Virginia or think about planning exit strategies. Incumbent utilities know with certainty the risks and service obligations they must face between now and the end of 2010.

With legislative certainty now reaffirmed, we believe all parties involved in or affected by the transition to a competitive electric market in Virginia should commit themselves to implementing restructuring and customer choice successfully. Only if all parties work together in a collaborative and constructive fashion can the Commonwealth realize the Restructuring Act's goal of competitive retail markets for the supply of electricity. We are hopeful that the General Assembly's policy decision to proceed with restructuring will be reflected in the Commission's 2004 report on the status of competition.

Sincerely,

E. Paul Hilton

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May 28, 2004

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

Re: State Corporation Commission Report on the Status of Competition Comments of Coral Power, L.L.C.

Dear Mr. Eichenlaub:

Coral Power, L.L.C. ("Coral Power" or "Coral") takes this opportunity to submit to the SCC principles that must be adopted for the development of an effectively competitive wholesale market in Virginia. It offers these principles based on its experience in power markets throughout North America and from its unique perspective as a wholesale competitor with a new 885-megawatt ("MW") gas-fired combined cycle generating facility located near Palmyra, Virginia in Fluvanna County (the "Fluvanna Facility").

Coral believes that the development of effective competition in wholesale and retail electricity markets in Virginia is in the public interest. Moreover, because Coral's business focuses on the development of (and participation in) competitive wholesale electricity markets, Coral offers a unique perspective of the status of competition in Virginia to date. Coral focuses its comments specifically on recommendations for the development of effectively competitive wholesale markets in Virginia.

1. Description Of Coral Power And Its Interest In The Development Of Effectively Competitive Wholesale And Retail Markets In Virgina.

Coral Power is a Delaware limited liability company that is owned by Coral Energy Holding, L.P., which is owned by subsidiaries of Shell Oil Company and Bechtel Enterprises Holdings, Inc. Coral entered into a long-term Energy Conversion Agreement ("ECA") with Tenaska Virginia Partners, L.P. ("Tenaska") in connection with Tenaska's

Fluvanna Facility. The ECA represents a very significant investment by Coral in Virginia's evolving energy markets.

Coral Power is also a supplier and marketer of electricity in markets throughout North America. Coral has experience with centrally dispatched, independently administered markets like those administered by the PJM Interconnection, L.L.C. ("PJM"), as well as with bilateral markets that do not have an independent market administrator.

The Fluvanna Facility is interconnected with the transmission lines of Dominion Virginia Power ("DVP"), and commenced commercial operations on May 1, 2004. Under the terms of the ECA, Coral has the exclusive right to provide natural gas to the Fluvanna Facility, and to obtain all of the electric energy generated by the Fluvanna Facility. Coral will market and sell this output in and around the Commonwealth of Virginia. As a combined cycle plant, the Fluvanna Facility can respond quickly to price signals and dispatch instructions in order to provide electric energy and other generation-related products and services, while supplementing base-load generation resources in the region. The region needs this type of generating resource.

Coral has a significant interest in the terms and conditions under which it can obtain transmission service and market the output of the Fluvanna Facility. Depending upon the ultimate configuration of Virginia's wholesale markets, the terms under which Coral can obtain access to transmission service across the region's transmission systems, the rates it will pay, and opportunities it will have to access energy, capacity, and ancillary service markets will change.

2. Key Principles And Recommendations For The Development Of Effective Competition In The Commonwealth Of Virginia.

Pursuant to Va. Code § 56-596 B of the Virginia Electric Utility Restructuring Act, Va. Code Title 56, Chapter 23 (as amended, the "Act"), the SCC is charged with reporting to the legislative Commission on Electric Utility Restructuring ("EURC") and to the Governor on the status of competition in the Commonwealth, the status of the development of regional competitive markets, and its recommendations to facilitate effective competition in the Commonwealth as soon as practical. The Commission's report is to include any recommendations of actions to be taken by the General Assembly, the Commission, electric utilities, suppliers, generators, distributors and regional transmission entities that the Commission considers to be in the public interest.

Id. Such recommendations shall include actions regarding the supply and demand balance for generation services, new and existing generation capacity, transmission constraints, market power, suppliers licensed and operating in the Commonwealth, and the shared or joint use of generation sites. *Id.*

Coral agrees with the observation that "a continued and unwavering commitment to retail choice and wholesale competition is needed to bring [the benefits of competition] to consumers." Joint Statement, p. 2. These comments focus on the key principles for the development of effective competition in the Commonwealth, and recommendations for further action.

a. Virginia's Incumbent Electric Utilities Need to Participate Fully in Fully Functional Regional Transmission Entities.

This issue is of critical significance to Coral, and is critical to the future success of Virginia's energy markets. Full participation in a fully functional RTO is an essential prerequisite for development of robust competitive markets, both wholesale and retail, and delays in the entry of Virginia's incumbent electric utilities into an RTO continue to pose a very significant obstacle to the success of competition in the Commonwealth.

Presently, the Commission has pending before it the applications of Appalachian Power Company ("APCo") and Dominion Virginia Power to join PJM. While § 56-579 of the Act requires Virginia's incumbent electric utilities to transfer control of their transmission assets to a regional transmission entity ("RTE")[1] by January 1, 2005, subject to Commission approval as provided in that section of the Act, it remains to be seen what conditions may attach to such approvals.

Coral is particularly concerned that Virginia's commitment to have its incumbent electric utilities join an RTE will not reach its full potential, or provide the greatest opportunity for the successful development of effective retail and wholesale competition in Virginia, if the participation of one or more of Virginia's incumbent electric utilities in an RTE is anything less than complete, competitive, and non-discriminatory.

Today, DVP and American Electric Power ("AEP") operate fully integrated systems, utilizing a centralized, security-constrained dispatch for their generation, while providing open access to their transmission systems. Like other vertically integrated utilities that are not part of independently-administered, competitive regional markets like

[1] RTEs are also referred to in the industry as RTOs. The terms "RTE" and "RTO" may be used interchangeably.

those administered by PJM, DVP and AEP manage congestion at the so-called "seams" of their transmission systems manually through the use of operating procedures, generation dispatch and redispatch, and transmission loading relief ("TLR") procedures.

The TLR procedure is an Eastern-Interconnection-wide procedure to allow the Reliability Coordinators to mitigate potential or actual transmission operating security limit violations; however, instead of utilizing open and transparent generation redispatch to manage transmission congestion, TLRs cancel power flow transactions rather than allowing parties to "buy through" the congestion. Moreover, because of the time it takes to arrange and implement TLRs (perhaps 30 to 60 minutes), they are not a satisfactory means of handling real-time emergency situations.

With TLRs significant transactions can be curtailed, when generation redispatch would allow the transactions to proceed. TLRs can also cancel energy sales that otherwise might be the most economically efficient means of meeting real-time power needs. They present significant obstacles to effective and efficient regional trading of electricity, which is needed to support the development of effective competition in Virginia. To place the magnitude of this problem in perspective, 19 percent (by volume) of all TLRs called in the United States since 1998 have involved PJM and AEP.

A transmission owner ("TO") that also owns generation and controls dispatch has the ability and incentive to utilize that dispatch to favor its own generation and to capture market opportunities, at the expense of competitors and consumers alike. Many market participants perceive that TLRs are used in a discriminatory manner. By declaring a TLR, a TO can curtail transactions when a redispatch of the TO's generation would allow other economically efficient transactions to proceed. A utility's continued control of these functions can create the perception that markets are less than open, transparent, and effectively competitive. Both the PJM and the Midwest Independent Transmission System Operator, Inc. ("MISO") market monitors have identified gaming and market power issues at the seams between market and non-market areas.

On the other hand, RTOs like PJM that manage congestion on the transmission system through the use of locational marginal pricing ("LMP") utilize an integrated security constrained economic dispatch for generation, but do so in an open, timely, and transparent manner. LMP permits PJM to maintain system reliability more efficiently than through TLRs.

Coral recognizes that there are several dockets pending before the Federal Energy Regulatory Commission ("FERC") that will consider the RTO choices of AEP, DVP, and other so-called "Alliance Companies" to join PJM. Coral is an intervenor in some of these FERC dockets.

Coral echoes the concerns of others that so-called "partial integration" or "phased integration" proposals may be offered as satisfactory solutions to Virginia's RTE requirement, where a Virginia utility may propose to transfer functional control of transmission facilities to PJM to independently administrator transmission access, calculate Available Transfer Capability ("ATC") and Total Transfer Capability ("TTC"), act as Reliability Coordinator, act as Market Monitor, and conduct regional planning and coordination of the seams between the systems of PJM, Virginia utilities, and other markets, but would *not* propose to integrate into PJM's markets.

While the Commission may not be able to comment directly on such issues, given its need to make decisions on the RTE applications of APCo and DVP and its participation in proceedings pending before the FERC, Coral joins others in expressing its concerns on these critical issues.

Should an RTE application by one or more of Virginia's incumbent electric utilities be approved that involves less than total integration into PJM's markets, this will adversely impact the competitive position of Virginia in the region, and the ability of wholesale and retail competitors to efficiently serve those markets. Moreover, Coral is convinced that this approach would adversely impact reliability, and reduce economic benefits to consumers in the region. In addition, less than full participation in PJM's markets will also present opportunities for gaming and the exercise of market power that may be difficult to monitor and correct. For these and other reasons, Virginia's incumbent electric utilities should be full participants in any Commission-approved RTE choice.

b. Virginia's Market Structure Should Include An Efficient, Liquid Spot Market.

Virginia presently lacks an efficient, liquid spot market. Without an efficient wholesale spot market, prices in the forward market serving Virginia will not be as reliable, transparent, or liquid. Markets that lack transparency and liquidity will cause suppliers to add risk premiums to their offers, resulting in higher-priced electricity for Virginia's consumers.

Coral acts a wholesale supplier to competitive service providers ("CSP") in several markets throughout North America. It is Coral's experience that retail markets are more successful in regions like that covered by PJM, where a liquid and transparent spot market exits. For Virginia, the lack of a transparent, efficient spot market means that CSPs and other load serving entities will miss opportunities to purchase power on a term basis at the most competitive prices, and suppliers such as Coral will miss opportunities to make otherwise-economic sales. Such risk premiums will create a disincentive for retail CSPs to participate in Virginia's retail markets until more favorable market rules develop.

It is clear that CSP retailers such as the *ad hoc* coalition of retail companies ("Competitive Stakeholders")[2] that submitted comments in response to your letter are interested in entering the Virginia market, but perceive the current wholesale market structure to be a barrier for this to happen in a meaningful way. To the extent that the appropriate design for wholesale and retail markets encourages participation from many entities, customers can realize the benefits that competitive suppliers can offer, such as customized hedging instruments to better match the needs and budgets of business customers.

c. Coral's Fluvanna Facility Is At A Competitive Disadvantage Unless Virginia's Wholesale Markets Are Effectively Competitive.

The Fluvanna Facility is a competitive enterprise that provides jobs and pays taxes like other enterprises in the Commonwealth. Coral's marketing and sale of its output in the region will help secure its long term viability as an employer, taxpayer, and supplier.

Virginia's failure to fully embrace a competitive market structure like PJM's, which includes spot energy markets, capacity, and ancillary services markets, places Coral at a significant competitive disadvantage with respect to its ability to offer these resources in the Commonwealth and to adjoining regions. This disadvantage is not theoretical. From May 1, 2004, the date the Fluvanna Facility commenced commercial operations, Coral has encountered barriers to its ability to effectively market the output from the Fluvanna Facility. Coral's competitors in other regions surrounding the PJM footprint are able to reach the PJM markets without having to pay transmission service export fees, and the opportunity to supply capacity and ancillary services gives them a significant advantage relative to generators like the Fluvanna Facility. As described above, the lack of an efficient spot market also acts as a tremendous obstacle. These

[2] The Competitive Stakeholders include Constellation NewEnergy, Inc., Direct Energy Marketing, Inc., Pepco Energy Services, Inc., Strategic Energy, L.L.C., and Washington Gas Energy Services, Inc.

barriers will remain unless and until Virginia's incumbent electric utilities become incorporated into a competitive regional market.

Competitive wholesale market structures will permit the Fluvanna Facility to be a valuable economic resource for Virginia and the region. The principle is simple. When the markets serving Virginia send a signal that it is efficient for Coral to offer energy, capacity, and ancillary services resources from the Fluvanna Facility to load serving entities (including utilities, cooperatives, and CSPs), it will do so. The Fluvanna Facility also supports local reliability needs. Accordingly, competitive wholesale markets will provide an opportunity for the Fluvanna Facility and Coral to prosper as businesses, while providing load serving entities and the electric consumers they serve with a competitive option to meet their reliability and resource needs.

3. Conclusion.

On behalf of Coral Power, L.L.C., thank you for the opportunity to provide these comments and recommendations. Coral Power believes that its recommendations are in the public interest, and should be adopted.

Very truly yours,

Thomas B. Nicholson

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May 28, 2004

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

Re: State Corporation Commission Report on the Status of Competition

Dear Mr. Eichenlaub:

On May 25, 2004, you received a joint statement from Allegheny Energy, Inc., Constellation NewEnergy, Inc., Direct Energy Marketing, Inc., Dominion Retail, Inc., Dominion Virginia Power, Virginia Energy Providers Association, Virginia Independent Power Producers, Pepco Energy Services, Inc., Strategic Energy, L.L.C., and Washington Gas Energy Services, Inc. (the "Joint Statement"). The Joint Statement reiterates the commitment of the signatories ("Joint Statement Signatories") to viable competitive wholesale and retail electricity markets in the Commonwealth of Virginia, and urges the State Corporation Commission ("Commission" or "SCC") to facilitate the process towards fully competitive retail and wholesale electricity markets by completing its review of the applications currently before it for the integration of incumbent electric utilities with a Regional Transmission Organization ("RTO"). The Joint Statement also calls for a re-commitment from stakeholders to strive for the successful development of a competitive market in Virginia.

The Joint Statement Signatories set forth their firm belief that continued restructuring is in the best interests of the consumers in the Commonwealth. While all the signatories agreed with the principles set forth in the Joint Statement, the *ad hoc* coalition of retail companies identified herein takes this opportunity to elaborate on those principles from their unique perspectives as retail competitors of Virginia's incumbent electric utilities.

1. Identification of Competitive Stakeholder Members

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

- Constellation NewEnergy, Inc., [Retail Competitive Service Provider ("CSP"), member of the Virginia Alliance for Retail Energy Markets ("VAREM")[1] and Joint Statement Signatory];
- Direct Energy Marketing, Inc. (Retail CSP, VAREM member, and Joint Statement Signatory];
- Pepco Energy Services, Inc. (Retail CSP and Joint Statement Signatory);
- Strategic Energy, L.L.C. (Retail CSP, VAREM member, and Joint Statement Signatory); and
- Washington Gas Energy Services, Inc. (Retail CSP, VAREM member, and Joint Statement Signatory).

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

In your April 26, 2004 letter to stakeholders ("April 26 Letter"), you state (p.2)

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

[1] VAREM is an *ad hoc* coalition of retail energy marketers. VAREM members participated in the last legislative session of the General Assembly, and voiced their views concerning Senate Bill 651 and the impact of that bill on the prospects for retail competition in Virginia.

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

2. Identification and Further Discussion of Key Principles and Recommendations for the Development of Effective Competition in the Commonwealth of Virginia.

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

In Part II of its August 2003 Status Report[2] to the EURC and the Governor, the Commission noted (p.2) a continuing lack of competitive options for Virginia's electric consumers:

> As we reported last year, the right to choose has not yet evolved into the ability to choose. While it is clear that the SCC, the utilities and the various stakeholders have effectively enabled almost universal retail access in Virginia, there is 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

[2] Report To The Commission On Electric Utility Restructuring Of The Virginia General Assembly And The Governor Of The Commonwealth Of Virginia Status Of Retail Access And Competition In The Commonwealth, *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* (August 29, 2003)("2003 Status Report"). Part II of the 2003 Status Report is entitled "Status Of Retail Access And Competition In The Commonwealth."

> energy priced so that switching customers may save money.

The Competitive Stakeholders anticipate that the Commission's 2004 Status Report is likely to include the same observation with respect to the status of retail access and competition in Virginia. This observation is likely to cause some to ask a fundamental question: *viz.*, Is it appropriate or acceptable public policy to permit a continuation of the *status quo* with respect to the level of competition in Virginia?

While some may continue to argue that Virginia is on the wrong course with respect to the introduction of competition in the electric utility industry, the Competitive Stakeholders, like the Joint Statement Signatories, believe that this is not the case. The fundamental question that the Competitive Stakeholders wish to address is as follows: "What is preventing the benefits of competition from reaching Virginia's consumers?"

The Competitive Stakeholders agree with the Joint Statement's observation that "all parties agree that a continued and unwavering commitment to retail choice and wholesale competition is needed to bring [the benefits of competition] to consumers." Joint Statement, p. 2. The Competitive Stakeholders also agree that "individual market participants may disagree as to the methods of successfully developing competitive markets in Virginia[.]" *Id.*

These comments focus on the key principles for the development of effective competition in the Commonwealth, and recommendations for further legislative and regulatory action.

a. Virginia's Incumbent Electric Utilities Need to Participate Fully in Fully Functional Regional Transmission Entities.

The Competitive Stakeholders agree with the Joint Statement (p. 2) that "[p]articipation in a fully functional regional transmission organization is an essential prerequisite for development of robust competitive markets, both wholesale and retail[, and that "[d]elays in the entry of incumbent Virginia utilities into an RTO continue to pose a very significant obstacle to the success of competition in the Commonwealth." *Id.*

Presently, the Commission has pending before it the applications of Appalachian Power Company ("APCo") and Dominion Virginia Power ("DVP") to join the PJM Interconnection, L.L.C. ("PJM"). While § 56-579 of the Act requires Virginia's incumbent electric utilities to transfer control of their transmission assets to a regional transmission entity ("RTE")[3] by January 1, 2005, subject to Commission approval as provided in that section of the Act, it remains to be seen what conditions may attach to such approvals.

The Competitive Stakeholders are concerned that Virginia's commitment to have its incumbent electric utilities join an RTE will not reach its full potential, or provide the greatest opportunity for the successful development of effective retail and wholesale competition in Virginia, if the participation of one or more of Virginia's incumbent electric utilities in an RTE is anything less than complete, competitive, and non-discriminatory.

The Competitive Stakeholders note that there are several dockets pending before the Federal Energy Regulatory Commission ("FERC") that will consider the RTO choices of American Electric Power ("AEP")[4], DVP, and other so-called "Alliance Companies" to join PJM.

In particular, the Competitive Stakeholders are concerned that so-called "partial integration" or "phased integration" proposals may be offered as satisfactory solutions to Virginia's RTE requirement, where a Virginia utility may propose to transfer functional control of transmission facilities to PJM to independently administrator transmission access, calculate Available Transfer Capability ("ATC") and Total Transfer Capability ("TTC"), act as Reliability Coordinator, act as Market Monitor, and conduct regional planning and coordination of the so-called "seams" between the systems of PJM, Virginia utilities, and other markets, but would *not* propose to integrate into PJM's markets.

While the Commission may not be able to comment directly on such issues, given its need to make decisions on the RTE applications of APCo and DVP and its participation in proceedings pending before the FERC, the Competitive Stakeholders want the CEUR, the other members of the General Assembly, and the Governor to understand their perspective on this critical issue.

Should an RTE application by Virginia incumbent electric utility be approved that involves less than total integration into PJM's markets, the Competitive Stakeholders believe that such an approach will adversely impact the competitive position of Virginia in the region, and the ability of wholesale and retail competitors to efficiently serve those markets. They are also concerned that this approach would adversely impact reliability, and reduce economic benefits to consumers in the region. In addition, less than full participation in PJM's markets will also present opportunities for gaming and the exercise

[3] RTEs are also referred to in the industry as RTOs. The terms "RTE" and "RTO" may be used interchangeably.
[4] APCo is one of the AEP operating companies.

of market power that may be difficult to monitor and correct. For these and other reasons, Virginia's incumbent electric utilities should be full participants in any Commission-approved RTE choice.

b. Virginia Still Must Come To Grips With The "Stranded Costs" Issue And Resolve It Expeditiously, Or Provide All Of Virginia's Consumers The Opportunity To Avoid A Utility's Wires Charges.

In enacting Senate Bill 651, 2004 Acts of Assembly Chapter 827, the General Assembly and the Governor have articulated a need to protect Virginia consumers from exposure to non-competitive electricity markets. Without debating here whether this approach to consumer protection is optimal, each of the Competitive Stakeholders believes that underlying flaws in Virginia's market structures remain that prevent competitors from bringing the benefits of competition to consumers. The changes needed to address these are not dramatic, nor do they require abandonment of the rate cap and fuel cost protections approved in Senate Bill 651.

The primary flaw has to do with the wires charge that Va. Code § 56-583 allows utilities to charge their customers in order to take service from competitive suppliers. This surcharge is supposed to be a mechanism for utilities to collect costs that are "stranded" by retail competition. The problem with this surcharge mechanism is twofold. First, no Virginia utility has ever had these costs documented or quantified, and there continues to be widespread disagreement on whether these costs exist at all. Second, since retail customers presently have little opportunity to avoid paying these undocumented surcharges, competitors have to absorb these costs if they hope to offer savings to customers and stay in business.

While a utility may propose to forego part or all of any wires charges it otherwise is authorized to charge,[5] such a mechanism permits a utility to dictate the terms of competition within its service territory. It is hardly surprising that such an arrangement is met unenthusiastically by competitive providers.

The new subsection E to Va. Code § 56-583, enacted as part of Senate Bill 651, authorizes industrial and commercial customers, as well as aggregated customers in all rate classes, to switch to a competitive service provider without paying a wires charge if they agree to pay market-based prices if they ever return to the incumbent electric utility (the "wires charge exemption program").

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[5] Dominion Virginia Power has made such a proposal a part of its retail access pilot programs pending before the Commission in Case No. PUE-2003-00118.

The biggest drawback to the wires charge exemption program is that it is limited for each utility to customers totaling not more than 1,000 MW or eight percent of the utility's prior year Virginia adjusted peak load within 18 months after the commencement date of the wires charge exemption program, and thereafter according to the SCC's regulations that are to be developed. Customers who make this commitment and obtain power from suppliers without paying wires charges are not entitled to obtain power from their incumbent utility at its capped rates.

This limitation is fundamentally at odds with the premise of open competition, because it unfairly limits the number of customers that would be eligible to make this choice. It also reduces the likelihood that competitors will be interested in participating in Virginia's retail electricity markets. The Competitive Stakeholders support the right of *all* consumers to have a realistic opportunity to choose a competitive supplier as soon as possible.

The Competitive Stakeholders also believe that a utility's just and reasonable net stranded costs should be quantified, and a recovery period established for any utility that is found to have such costs. In the alternative, the CEUR and the Governor should revisit the version of the wires charge exemption program that was originally endorsed by the CEUR. This version would have allowed all customers the opportunity to purchase electric energy from competitive suppliers without the obligation to pay the wires charge surcharge, as long as they were willing to accept market-based pricing if they returned to their utility for generation service.

Finally, the wires charge exemption program does not place a limitation on a customer's loss of capped rate protection in exchange for a limited avoidance of wires charges. As presently enacted, the wires charge exemption program requires a customer to choose between the avoidance of wires charges through July 1, 2007, and the continued protection of capped rates through December 31, 2010, the date Senate Bill 651 set for rate cap protections to end. The Competitive Stakeholders believe this will create a disincentive to select an alternative supplier until the authority of a utility to collect wires charges expires in July of 2007, and will undermine the development of effective competition in the Commonwealth. On the other hand, an amendment to the Act that permits a customer to return to capped rates at the expiration of the wires charges collection period in July of 2007 would provide a fair balance of risk and reward for customers, utilities, and competitors alike.

c. Distribution Cost Treatment Should Not Be Tied To Restructuring, Especially After The End Of The Stranded Cost Collection Period (July 1, 2007) - Distribution Has Not Been Deregulated.

In extending the rate cap period, Senate Bill 651 did not address an underlying issue associated with that extension. Specifically, the rate cap extension may deny to consumers the opportunity to enjoy savings that are expected if the Commission were to exercise its continuing authority to regulate on a cost-of-service basis the monopoly transmission and distribution services of Virginia's utilities. Contrary to the arguments of some, this is not a pretext for a return to regulation, or for greater SCC control over the competitive market. Rather, it represents sound public policy that has been part of the Act since it was passed in 1999.

The enactment of Senate Bill 651 raises questions concerning the continued viability of the legislative intent behind the Act when it was adopted—and the original legislative and regulatory compact between utilities, consumers, and competitors—with respect to the rates utilities charge consumers for transmission and distribution service, and the Commission's ability to regulate such rates and service.

Specifically, Va. Code § 56-580 A directs (emphasis added) that "[t]he Commission is to *continue* to regulate pursuant to [Va. Code Title 56] the distribution of retail electric energy to retail customers in the Commonwealth and, to the extent not prohibited by federal law, the transmission of electric energy in the Commonwealth. Moreover, "[n]othing in [the Act] shall impair the Commission's *existing* authority over the provision of electric distribution services to retail customers in the Commonwealth including, but not limited to, the authority contained in Chapters 10 (§ 56-232 et seq.) [which contains the Commission's ratemaking authority] and 10.1 (56-265.1 et seq.) of [Va. Code Title 56]." Va. Code § 56-580 E (emphasis added).

The Competitive Stakeholders recommend that the original legislative intent of the Act, embodied in existing language found in Va. Code § 56-580, be reaffirmed in the coming legislative session. The Commission should be given clear guidance that it has the authority to assure that the rates of a utility's regulated transmission and distribution service do not artificially subsidize the price of its generation service, which is subject to competition. Subsidies of this sort put a damper on competition, and the Act recognizes the continuing authority of the SCC to make these important adjustments.

These changes and others will go a long way toward getting competitors excited about participating in Virginia's retail electricity markets. Consumers are interested in competition—that much is evident from the over-subscription of customers wanting to participate in Dominion Virginia Power's pilot programs. Removing artificial barriers to competition will ensure that another critical component of retail competition—competitors—also will be encouraged to invest in Virginia. If the rules of competition are fair and open, competitors can bring the benefits of competition—downward pressure on prices, more choices, and better service—to Virginia's consumers.

On behalf of Constellation NewEnergy, Inc., Direct Energy Marketing, Inc., Pepco Energy Services, Inc., Strategic Energy, L.L.C., and Washington Gas Energy Services, Inc., thank you for the opportunity to provide these comments and recommendations.

Very truly yours,

Thomas B. Nicholson

May 25, 2004

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

Dear Mr. Eichenlaub:

The attached joint statement reiterates the commitment of the signatories to a viable competitive electricity market in the Commonwealth. This joint statement from the parties represents agreement on the principles contained therein. Importantly, this statement urges the Commission to facilitate the process towards a fully competitive retail and wholesale electricity market by completing its review of the applications currently before it for the integration of incumbent electric utilities with a Regional Transmission Organization. It also calls for a re-commitment from stakeholders to strive for the successful development of a competitive market in Virginia. It is the firm belief of the participants to this joint statement that continued restructuring is in the best interests of the consumers in the Commonwealth.

Allegheny Power
Constellation NewEnergy, Inc.
Direct Energy Marketing, Inc.
Dominion Retail, Inc.
Dominion Virginia Power
Pepco Energy Services, Inc.
Strategic Energy
Virginia Energy Providers Association
Virginia Independent Power Producers
Washington Gas Energy Services, Inc.

JOINT STATEMENT ON COMPETITION AND RESTRUCTURING 2004
May 25, 2004

The electric utility industry in Virginia is undergoing significant changes. Restructuring and retail competition hold the potential to aid consumers through innovation, downward pressure on prices and enhanced reliability. In the Commonwealth, retail and wholesale competition can provide benefits to consumers.

Continued legislative and regulatory certainty is a necessary component for the ultimate success of restructuring in Virginia and the successful development of the competitive retail market. While individual market participants may disagree as to the methods of successfully developing competitive markets in Virginia, all parties agree that a continued and unwavering commitment to retail choice and wholesale competition is needed to bring these benefits to consumers.

With these factors in mind, we jointly offer the following comments on restructuring and competition in response to the Commission Staff's April 26 letter of invitation.

- Participation in a fully functional regional transmission organization is an essential prerequisite for development of robust competitive markets, both wholesale and retail. Delays in the entry of incumbent Virginia utilities into an RTO continue to pose a very significant obstacle to the success of competition in the Commonwealth.

The General Assembly has twice recognized that functioning RTOs are necessary for the successful development of competitive markets in Virginia. In 1999 the Restructuring Act directed all transmission-owning incumbents to join or form RTOs (called Regional Transmission Entities in the Restructuring Act). The 2003 General Assembly reiterated this directive, passing amendments to the Restructuring Act that directed all incumbents to transfer control of their transmission assets to regional entities no later than January 1, 2005, subject to Commission approval.

In comments submitted to the Commission in 2003, a wide range of stakeholders reiterated the view that membership by all transmission-owning incumbents in a functioning RTO is critical to successful competition in Virginia. The Commission's annual report on the status of competition released on August 29, 2003 acknowledged these comments. "Perhaps the most common issue raised among the comments submitted in response to the Staff's letter regards the lack of a fully functional RTO as the major obstacle" to an active competitive market in Virginia, the report said. (*2003 Status Report: The Development of a Competitive Retail Market for Electric Generation within the Commonwealth of Virginia*, Part III, page 10)

Membership by all transmission-owning incumbents in a functioning RTO would promote market transparency and reaffirm nondiscriminatory access to the interstate transmission grid for competitive suppliers and their customers. Access to a wider generation asset pool will enhance reliability, facilitate both wholesale and retail competition and provide savings opportunities for consumers. To promote the orderly development of Virginia's restructuring initiative, it is imperative that the Commission complete its review of these PJM membership applications of American Electric Power and Dominion Virginia Power and make appropriate recommendations to require these utilities to join the PJM Interconnection LLC in compliance with the January 1, 2005 date in the Restructuring Act.

- Continued legislative certainty – and a high degree of regulatory certainty – are necessary components for the success of Virginia's restructuring program and the successful development of the competitive market.

Electric restructuring and retail competition are functioning in other parts of the country such as the District of Columbia, Maryland, New Jersey, New York, Texas, Maine, and Massachusetts. The General Assembly has now reaffirmed that continued restructuring is in the best interests of Virginia consumers. In light of that reaffirmation, we believe that by working together in a collaborative and constructive fashion during the transition we can bring restructuring's benefits to consumers and realize the General Assembly's goal of a competitive retail electricity market in the Commonwealth. To this end, consumer representatives, merchant generators, competitive service providers, incumbent utilities – and the Commission and its Staff – should recommit themselves to implementing restructuring and customer choice successfully. These stakeholders should further commit to ensure that effective competition is promoted in Virginia through operational flexibility, systems changes and incremental rule changes that allow consumers ready access to the competitive market. Additionally, these commitments should be clearly stated in the Commission's 2004 report on the status of competition in Virginia.

Philip J. Bray (by DRB) (signature)

Philip J. Bray, Esq.

Allegheny Power

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Constellation NewEnergy, Inc.

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Washington Gas Energy Services, Inc.

Virginia Citizens Consumer Council

2004 Status of Electric Restructuring in Virginia: The Consumer Perspective

Virginia decision makers have concluded that our future for the provision of electricity lies in the developing competitive market. For a competitive market to truly be competitive, there must be a level playing field among competitive providers, and the "power" of consumers as a whole and providers as a whole must be balanced. If this does not happen, then the competitive market will not work effectively. Historically, government regulation, mostly at the state level, has been the tool used to balance the power of consumers and providers. Virginia began the restructuring process under the perceived push of either doing it ourselves or having it done "to" us by federal entities unlikely to fully consider the unique needs of Virginia. We knew that historically our electricity prices have been considerably lower than the national market price, and definitely lower than the prices in states to our north and west. Today we are on the verge of voluntarily giving up state jurisdiction over key aspects of the electric system without the guaranteed protection we claimed to seek at the outset of this venture.

Unfortunately for Virginia consumers, the promise of even a net no-loss situation, much less any potential benefit, will never be fulfilled. To consumers, real competition means genuine choice among a variety of reliable providers without huge financial or service quality risk. Over the next few years consumers are going to realize that our leaders have given away the low electricity prices that have been critical to our economic progress as individual families and communities. Maybe this would have eventually happened anyway, but Virginia did not have to be the first low cost energy state to voluntarily give up such a crucial benefit. Investor owned utilities stand to gain much at the expense of consumers. Over the last year, this has become increasingly evident.

Prices are going up and will not go down. One of the ways that the imbalance of power between Virginia's utilities and its consumers is clearly demonstrated is the fact that currently there is no way for consumer rates to go down – no matter what happens in the marketplace.

Virginia's 2004 electricity legislation failed to allow consumers to call for a rate case under any circumstance. Only the utilities can petition for rate changes. While these opportunities are somewhat limited, the reality is that utilities have a significant advantage since no entity can require that prices go down, regardless of what happens with costs, and they are guaranteed that prices will go up if costs do. Now that this promise has been made, it is going to be hard for legislators to take it back. Any attempt will be met with cries of harm due to regulatory uncertainty and / or distress from loss of guaranteed income. However, the SCC should make the case for rebalancing the power of utilities and consumers, and the administration and legislature should take action to fix the problem.

When the original restructuring legislation was passed in Virginia, it was anticipated that a way would be found to calculate the stranded costs incurred by utilities. The intent was to assure that incumbent utilities were not put into a non-competitive situation by the costs related to the transition and there was a promise to consumers that we would not have to overpay for these costs. This promise has been broken.

Our incumbent utilities have adamantly refused to prove these costs, because they do not exist. They know that if they opened their books, everyone would see that they have made such high profits that they would be forced to return some of them to rate payers. Thus they have refused to provide the proof that they deserve this income because of specific costs expended and proof that they will not be paid off either before the capped rate period ends or in the competitive market. No decision maker has stepped up to force them to do it.

Worse, incumbent utilities have managed to change the original intent of the law by convincing enough decision makers that the original legislation did not promise rate payers any money back under any circumstance and that it really promised that they could keep any profits as a carrot to move to competition that they requested. *As a result, the General Assembly has allowed incumbent utilities to unfairly strip dollars from consumers' pockets in quantities that far surpass the small tax increases that have caused so much turmoil within the Commonwealth.* The legislation passed in 2004 adds insult to injury by allowing the cost of tax breaks lost by utilities to be passed to consumers. <u>The State Corporation Commission and/or legislature must help level the playing field between the utilities and their customers concerning these issues.</u>

Craig-Botetourt Electric Cooperative, which serves my home, is already facing significantly higher prices for electricity. AEP sent us notice on the last day of February that effective March 1, 2005, they were terminating the service contract that has existed since August 15, 1984. Currently we are purchasing our electricity for a *wholesale* price of approximately 3.75¢ per KWH. As of March 1, 2005, our wholesale price will become approximately 4.5¢ per KWH. Both the current price and the new price are significantly higher than any of the *retail* prices AEP is charging its customer groups. Based on load, the customer group that we're closest to is large power subtransmission, currently charged a retail price of 2.7¢ per KWH. AEP refused our request to be served at that retail rate and acknowledged for customers served above their native load, future contracts will be at open market prices at the highest rate possible. Taking into consideration the difference in retail and wholesale rates and rounding a little, Craig Botetourt customers are going to be paying roughly *twice* what a similar load pays on the AEP system and facing a significant increase in cost. Family budgets, local government budgets and business budgets will be stretched by this increase.

This is the kind of situation that all Virginians can expect to face by the time the rate caps are removed. Unfortunately, the rural areas of our state, which are among the areas with the lowest income levels, are already facing these increases. Cooperatives have no choice but to pass on increased costs like these and there are no lower cost alternatives since the power must be purchased. There should be no surprise in the future when rural areas' financial problems increase and the number of companies offering jobs in rural areas declines compared with other areas of the state and there are increased demands on the state budget to assist stressed areas.

From the Blackouts last year, it is clear that *our country needs to significantly upgrade our transmission grid.* Also, in the post 9-11 world, there is a need to increase system security.

Obviously, costs will have to be paid and we should expect to pay them. This means that transmission costs will increase regardless of other decisions that may be made.

On May 20, 2004, AEP CEO Michael Morris told participants at the Edison Electric Institute conference in New York: "It's illogical for us to believe that rates are coming down. We need to start telling the world that this is one hell of a bargain." *Until now, utility executives have been telling Virginia decision makers that we could expect savings from restructuring – even in very low cost AEP territory.* We've been had. <u>All efforts now must focus on regaining Virginia's benefit from historical decisions that kept our rates lower than the national average. The goal of any action should first be maintaining our historical low comparative cost for electricity.</u>

Effect of the extended price caps on consumers. *Dominion Customers:* The price caps that exist today have been extended until 2010. For Dominion customers, this means that they only have the future risk of possibly paying more for fuel when the rates are re-examined in 2007. However, they are now paying the highest fuel rate in history. The legislation was passed under the threat by utility officials that these historically high rates would increase again this year if they were not guaranteed to keep at least the current rates until 2010. This was done in the face of documented long term projections that energy costs will go down by the end of the decade. Before the legislation was even signed by the Governor, analysts in New York were touting the magnificent deal that Dominion and its stockholders got from Virginia. Although energy prices are high right now, analysts project huge earnings for Dominion in a few years and they specifically noted that these will not be shared with rate payers. Since there was no rate case for Dominion shortly before or at the time restructuring began, and at that time rates were generally declining, Dominion customers are overdue for a rate reduction. The fuel increase that occurred recently was done through unfair single rate rate making that only benefits the utility. <u>Ratepayers should share in any savings if fuel rates go down. It is not fair to make rate payers responsible if prices rise if they cannot possibly benefit when fuel rates go down. This unleveled playing field must be fixed.</u>

AEP: For AEP customers, the 2004 legislation is far more devastating. AEP, the largest electricity generator in the nation and one of the largest electric utilities in the nation, has not sought a fuel rate increase in Virginia, recently. In fact, its last attempt to achieve a rate increase resulted in a decrease. Now, in addition to facing higher fuel costs, it is under heavy pressure to make expensive environmental and security improvements across its system. Comparatively, Virginia is a small segment in AEP's system, its administrative presence in Virginia is minimal, and it is unlikely that Virginia will ever again be a critical part of AEP's system. However, the 2004 legislation essentially gave powerful AEP a blank check signed by its Virginia rate payers for any environmental or security improvements.

While these can be assessed only once a year, any costs incurred can be passed straight to Virginia rate payers. AEP is a smart company and we can expect it to take full advantage of this opportunity and get as much paid for by Virginians as possible. Because Virginia has long been served by out-of-state generation and AEP has not been forced to specify which units serve Virginia, the Company can easily decide to now assign the expensive improvements to their Virginia customers. They can also charge these costs in an accelerated manner so they are paid off when the rate caps are removed. The SCC must carefully scrutinize these expenses and assure that Virginians ONLY pay for the portion that are based on a fair allocation of improved facilities across the AEP system. It must also assure that costs for investments with long term benefit are properly charged so Virginia consumers only pay the portion due for the percentage of the useful life of these improvements that they will actually use between now and 2010.

There is no competition and it is unlikely to occur well beyond 2010. From a consumer perspective, there is no effective competition anywhere in the nation. If there was, consumers would have multiple choices of retail level providers vying for their business in a transparent, fair and reliable manner. Nationwide, consumers have received few competitive bids and even in states with widely advertised successful restructuring, large groups of consumers, especially in rural areas, have not received competitive offers.

Again, speaking to the Edison Electric Institute conference in New York, AEP CEO Michael Morris said that the merchant power sector is "dead as a doornail." Plans for a national competitive market depend upon a vibrant merchant power sector. Virginia has expedited approval processes and made every attempt to accommodate the needs of merchant power. However, until national change occurs, which we cannot influence greatly, Virginia's market will not work.

Recognizing that the market is not ready, our 2004 legislation extended the life of our rate caps. In the process our incumbent investor owned utilities got a greater long-term advantage over potential competitors than already inherently existed because of their incumbency. As described above, Dominion has the opportunity to make investments with excess earnings that will allow it to position itself at further advantage to new competitors when price caps are removed. Likewise, by guaranteeing AEP that Virginia rate payers will shoulder the burden of their environmental and security expenditures (and it seems that these categories are broad enough to include just about any possible expenditure), AEP has a tremendous opportunity to position itself ahead of future potential competitors.

The SCC should convince the legislature to change the imbalance between incumbent utilities and potential competitors so that there is potential for competition.

Distribution line maintenance and repair. In the competitive market, the bottom line cost matters a whole lot more to utilities than does customer service, especially in an environment where consumers really have no choice. Local distribution companies have little incentive to attempt to hold on to customers for their generation colleagues by providing high level service in today's environment. During September and October 2003 many Virginians discovered the hard way how few resources are allocated to line maintenance and repair by our utilities. Even some Dominion customers who live in the city of Richmond found themselves without power for a week or longer. Consumers widely believe that some of the efficiencies that utilities have obtained have occurred at the expense of careful maintenance to prevent outages and sufficient staff and equipment to complete repairs in a reasonable time.

The problems are not just related to major storms, however. Once again, I will use my Cooperative, Craig Botetourt, as an example. The average hours that our power has been off because of power supplier issues increased from an average of .71 hour in 1999 to 12.94 hours in 2003. We did not lose power during Hurricane Isabel, so that does not explain the tremendous difference. By far, power supplier problems account for most of the time service was interrupted on the system. It appears that Dominion's actions to improve efficiency are the root cause. Now crews that repair problems have to drive several hours since their offices have been consolidated out of our area. A number of skilled repair workers have retired and the replacement workers lack their skill and experience.

Fair and adequate consumer representation in the decision making process. Recognizing the systemic problem of inadequate consumer involvement and consideration in the process of creating a restructured electric market in Virginia, Urchie Ellis requested effective consumer representation within the SCC. This was denied on the basis that the Attorney General's Consumer Counsel has that responsibility. Unfortunately, the Consumer Counsel sided against consumers and with investor owned utilities during the 2004 legislative session to get extremely anti-consumer legislation passed. This proves that consumers have no dependable advocate in state government.

The original electric restructuring act provided for a consumer panel to advise the process as a means of assuring appropriate consideration of consumer issues. That group has had little autonomy. It has been held to addressing only issues of comparatively small import and prohibited form addressing the most critical issues. It has not been taken seriously by decision makers and the counsel it has provided has been largely ignored in the legislative agenda. It did not even meet during 2003.

Further, investigation of the 2003 minutes of the Commission on Electric Utility Restructuring reveals that while utilities were prominently involved in every meeting, consumer groups and individual consumers were not granted a single opportunity to address the group. Further, the issues included have not been considered from a consumer point of view. This is not surprising since in the past most members appeared to be largely uninterested in even listening to the consumer perspective.

If we are to have a fair competitive market, consumers must obtain equal representation and consideration in the decision making processes. Elected officials must depend upon the financial support of business to get into and stay in office and Virginia's large businesses dominate decision making processes. <u>Virginia currently has a systemic problem that makes it impossible to achieve a fair balance between the needs of business and the needs of consumers. This must be changed.</u> Creating a fair balance is not anti-business. In fact, leveling the playing field between consumers and big business will actually help small businesses that want to compete in our market. It will also assure that the families of even the dominant businesses will find the marketplace to be fair.

Regional transmission organization. Currently there is tremendous pressure for Virginia to accept our incumbent utilities' demand to make an irrevocable decision and immediately join PJM. Consumers are opposed to such a move at this time. VCCC is not convinced that the basic structure planned will provide for a transparent and fair marketplace. Very large regional transmission organizations are a new concept that has not been proven to work effectively so joining now would mean joining an experimental venture. While the concept allows multi-state utilities ease of operation, it significantly diminishes the influence of individual states and consumers, systemically increasing the already imbalance between utilities and consumers.

Although Virginia is geographically on the edge of the area proposed to be the ultimate PJM network and should therefore have the opportunity to choose among both a northern and a southern network, at this time the only viable network is PJM's. Researchers are evaluating its structure among a number of other options and there is no broad-based agreement that it is the best one. Thus, there is no opportunity for choice unless this decision is delayed. From the state's perspective, once made, it is an irrevocable decision.

PJM has been rapidly expanding its reach in recent years. The concept of operating such a large segment of our nation's electric grid as one unit is still experimental. It has never been done. Some observers believe that the magnitude PJM is seeking is beyond its effective managerial reach. Others note that from a security standpoint, creating such large and highly integrated networks could make us more vulnerable to terrorist attack.

There are structural market issues that need to be resolved so that the needs of consumers and business are fairly balanced if PJM's system is to work in the long run. If we accept the PJM strategy of LMP, owners of transmission will have *no incentive to build additional transmission* to reduce congestion. In fact, owners will earn significantly more if transmission is tight. No reasonable company will voluntarily build new transmission when doing so reduces its potential earnings. PJM has clearly stated that it will not force building of additional transmission for only economic reasons. Already, the eastern shore of Virginia is suffering from this problem. PJM has not taken action, nor does it plan to.

For areas seeking to obtain new electricity intense industry, there will be huge up-front costs to get the transmission needed and this may make it economically impossible for power constrained areas to get new jobs. Only existing congestion is proposed to be protected from price spikes for transmission if we move to PJM and consumers are not convinced that the protection is adequate.

PJM's system of large committees that meet hundreds or thousands of miles from Virginia and its dominance by utilities in decision making processes guarantees that neither consumer groups nor representatives of state government will have potential to adequately influence decisions. Virginia will have only one vote among many, losing prominence in critical decision making processes. On the other hand, PJM's structure will allow individual incumbent utilities to gain prominence. There is no systemic balance of the perspectives and motives of business and consumers in PJM. It is designed to first meet business needs. It is highly unlikely that Virginia will have any means of influencing a redesign that more fairly balances perspectives unless it happens before Virginia joins the organization. <u>Virginia should not join PJM until its decision making structure fairly balances perspectives.</u>

A decision to join PJM is not only a decision to join a transmission organization, it is an irrevocable decision to join a market. VCCC does not understand how Virginia's energy costs can decline if we join a market with a higher average cost than ours. *Economics indicate that if we join a market with higher cost than ours, our costs will increase* even if overall costs in the market decrease. If our utilities join PJM, we need to be prepared for higher prices. When Delaware joined PJM its energy prices more than doubled. Pennsylvania is said to have excess energy that could cause our prices to decline. However, if that is true, why haven't Pennsylvania's prices dropped? They are higher than ours. Prices in the south are more like ours. It would be better for consumers if our utilities joined a regional transmission organization to our south. Since one does not exist today, it seems short-sighted for Virginia to make an unchangeable selection. Virginia should avoid taking irrevocable radical action of prematurely joining to the only existing regional transmission organization, opting for the conservative path of waiting until more options exist or until PJM's system resolves the existing imbalance of power between utilities and consumers.

Other issues. From the outset of Virginia's restructuring process, VCCC has clearly stated that *consumers do not want to pay more **just** to have a choice of providers*. That has not changed. We prefer to pay less. If we must pay more, we want an increase in value.

Consumers remain concerned about how the competitive electric market will assure that *low income people will be guaranteed at least a minimum supply of electricity at a price they can afford.* We know that a purely competitive market does not assure that everyone gets some of every product. Electricity is a basic necessity of modern life. Our restructuring legislation assumes that providers will make sure that everyone has service. Specific, enforceable plans need to be made to assure there is affordable, dependable electricity for those who because of income level, geographic location or other reasons are less desirable targets for competitive providers.

Consumers are also interested in the effect of our energy decisions on the environment. Virginia does not adequately promote Energy Star products. We lack an effective strategy for consumers to experiment with and select distributed generation and other new technology. Our system is being designed primarily around the needs of large corporate entities that sell electricity. Opportunities are needed for meeting the needs of others, as well.

Decision makers should keep these issues in mind and address them when there is an opportunity. They remain important to consumers and cannot be ignored forever.

Until the powers of consumers and all energy providers are balanced so that no entity has a huge advantage over another, the competitive electric market is not going to be successful. In the last year, the balance has swayed decisively in the direction of incumbent investor owned utilities, to the detriment of consumers and potential competitors. Significant changes must be made to create a fair marketplace.

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May 24, 2004

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 26, 2004, 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 Virginia Power and AEP-Virginia, respectively.

In response to last year's request of the Commission Staff for comments on the status of competition, the Committees observed that retail competition for generation services had 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, we stated, little, if anything, had changed since the prior year.

That situation remains unchanged; 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 attachments, which are intended to assist in evaluating progress to-date and prospects for future success. They include:

[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.

Attachment 1: Report Card on Virginia Electric Restructuring. The report card evaluates progress on key issues related to competition and restructuring. It reveals low or failing grades on the degree of retail competition, prospects for future customer savings from competition, customer rates during the transition to competition, the assessment of stranded costs and benefits (*i.e.*, whether power plants are worth more or less than book value), functioning of a regional transmission entity, and entry of independent power producers. The only "A" grade is utility earnings. While "capped rates" may provide incentives for reduced distribution and transmission reliability, that category receives no grade because it is still being assessed.

Attachment 2. Implications of Maryland Wholesale Bid Prices for the Future of Electric Restructuring in Virginia. Attachment 2 discusses the end of Maryland's capped electricity supply rates and the implications for Virginia. Capped electricity supply rates in Maryland end this summer, at the end of its transition period to retail competition. This will mean significant rate increases for Maryland electric customers. Maryland's experience does not bode well for prospects for customer savings from customer choice in Virginia. Retail customers of electric utilities in Virginia may remain on their respective utility's "capped rates" until 2011, so they will not be forced to pay market prices prior to that year.[2] If, however, such customers were forced pay market prices now, or if market prices in 2011 were similar to, or higher than, they apparently are now in PJM, it appears that, based on the wholesale bid prices in Maryland for standard offer service, electric rates for customers in Virginia would increase significantly.

Attachment 3: "Dominion: Capped Rates Equal Profit." DVP's earnings do not appear to have suffered as a result of restructuring. In fact, the SCC Staff's review last summer of DVP's 2002 earnings showed that it was overearning under "capped rates" and that its rates would be reduced by about 10%, or $400 million per year, if they were re-set based on its cost of service. Staff's review of 2003 earnings has not commenced. Recent amendments to the Restructuring Act extend DVP's capped rates through 2010 and freeze its fuel factor through June 30, 2007. Dominion Resources, Inc. ("DRI"), DVP's parent holding company, projects earnings increases of 5% to 7% in coming years, emphasizing the positive earnings impact of the recent amendments. Attachment 3 includes excerpts from DRI's presentation at a meeting in New York earlier this month between DRI officials and financial analysts and DRI's projected earnings increases. The excerpt indicates, *inter alia*, that enactment of the recent amendments "opens doors to increased earnings" for DRI. The attachment also includes a news article containing highlights of the meeting.

Attachment 4: Dominion Virginia Power's Request to Defer $280 Million of RTO Costs until 2011. Attachment 4 discusses DVP's request to the Federal Energy Regulatory Commission ("FERC") to defer $280 million in estimated RTO-related costs until after 2010, when its "capped rates" are scheduled to expire. DVP seeks the deferral in order to allow such

[2] The State Corporation Commission ("SCC") has the authority to terminate "capped rate" service prior to the end of 2010 if it determines that an effectively competitive market for generation services exists; however, in view of the progress of competition to-date and recent trends, such an SCC determination must be regarded as highly unlikely.

costs to be passed through to its customers. DVP represented to the General Assembly, however, that the recent amendments to the Restructuring Act, which extend its "capped rates" through 2010 and freeze its fuel factor until July 1, 2007, would benefit its customers by imposing on DVP the risks of new costs.

Attachment 5: Presentation of Jeff Pollock on behalf of the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates before the Commission on Electric Utility Restructuring. The Restructuring Act's wires charges and "capped rates" are intended to permit utilities to recover "stranded costs," *i.e.*, unrecoverable costs resulting from electric restructuring and competition in Virginia. On behalf of both Committees, Mr. Pollock presented the results of an analysis of stranded costs for DVP and Appalachian Power Company ("APCo") at a meeting of the General Assembly's Commission on Electric Utility Restructuring on November 24, 2003. (Attachment 5) He concludes that neither utility has any stranded costs and that, using a methodology for measuring stranded costs developed by Moody's Investors Service, AEP-Virginia and DVP would have stranded benefits of $874 million and $1.2 billion, respectively.

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 the above comments. Electric restructuring has not worked so far in Virginia, and current developments do not bode well for its future success.

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

Sincerely,

Louis R. Monacell

Edward L. Petrini

#678047

ATTACHMENT 1

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 one supplier that temporarily offered to sell "green" power at prices higher than the utility's capped rates, no supplier has offered to serve any retail customers.
Prospects for future savings from retail choice	D	Present market prices and trends suggest that American Electric Power's ("AEP's") customers have no prospect for future savings. Most of Dominion Virginia Power's ("DVP's") customers' prospects for such savings are dim in view of the likelihood of market prices exceeding capped generation rates by 2007.
Customers rates during the transition to competition	D	The State Corporation Commission ("SCC") Staff has issued a report indicating that DVP's rates are excessive by 10% and would be reduced by approximately $400 million per year if its rates were to be reset based on cost of service. Rates for customers of AEP may not have been excessive; however, 2004 amendments to the Act encourage unfair single issue rate increases for AEP without the ability to review the total cost of service to determine whether there are any cost reduction offsets. Rates of DVP's customers have soared since the Act the passed in 1999 because the Act has permitted rate "adjustments" to reflect increased fuel costs, and such costs have increased. A 2004 amendment to the Act freezes DVP's 2004 fuel factor through June 2007.

Utility earnings	A	DVP's annual report to the U.S. Securities and Exchange Commission ("SEC") shows that, on a total company basis, it earned more than 12 % on equity in 2003, down from more than 17% in 2002. DVP's holding company, Dominion Resources, Inc. ("DRI"), acknowledges now earning a 14% return on equity while emphasizing the importance of the recent extension of DVP's capped rates through 2010 and the freezing of its fuel factor until July 1, 2007, in its projected increases in DRI's earnings by 5% to 7% per year. Appalachian Power Company's Virginia electric business appears to have produced modest over-earnings during 2002 according to a recent SCC Staff report. Comparable earnings data for 2003 are not available.
Assessment of stranded costs and stranded benefits (whether power plants are worth more or less than book value)	F	The Virginia Electric Utility Restructuring Act ("Act") requires an assessment of whether utilities have over- or under-collected "stranded costs" (*i.e.*, costs rendered unrecoverable as a result of restructuring and competition). Despite the likelihood that no stranded costs exist, no such determination has been made. In fact, the existence of significant stranded benefits is more likely. According to the SCC Staff, since DVP's rates were capped by the Act effective July 1, 1999, DVP has earned more than $800 million toward stranded cost recovery, yet no stranded costs may even exist.
Functioning of Regional Transmission Entity (RTE)	D	The Act initially required utilities to join an RTE by January 1, 2001. Neither DVP nor AEP 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 now propose to join the PJM Interconnection, LLC ("PJM"), and they may join in late 2004 or during 2005. Neither has yet joined the PJM.
Entry of independent power producers	D	Generation owned or controlled by DVP and AEP continues to dominate Virginia's generation market. Independent power producers have built little new generation since passage of the Act. In fact, DVP has added to its generation fleet more MWs than the independents. As a result, market power has not been eliminated and possibly has been enhanced.
Reliability of distribution and transmission system	No grade yet	Capped rates could motivate Virginia utilities to decrease expenditures on reliability in order to increase profits and thereby reduce reliability. The SCC is collecting data on the number and duration of outages in order to assess trends.

ATTACHMENT 2

Implications of Maryland Wholesale Bid Prices for the Future of Electric Restructuring in Virginia

Maryland's frozen ("capped") electricity supply rates for electric utilities end this summer, at the end of its transition period to retail competition. The capped rates are based upon each utility's cost of providing generation, transmission, and ancillary services as part of its bundled service to its customers. Rates for standard offer supply service from the local utility to customers that do not choose a competitive service provider will replace the current capped electricity supply rates. Utilities have solicited and accepted bids from wholesale suppliers seeking to provide the new standard offer service, and have awarded contracts to wholesale suppliers based upon the bid prices. This change in Maryland from capped rates based upon the local utility's cost of service to standard offer service based upon wholesale suppliers' bid prices will result in significant increases in electricity rates to Maryland's citizens and businesses.

Rates for electricity supply in Maryland for larger industrial and commercial customers – defined as customers with a demand greater than 600 kW – could increase by 45% or more if such customers have received electricity supply service from their local utility and continue to do so. Total electricity bills could increase on the order of 35% or more. Such customers, moreover, will receive the option of standard offer service at a fixed price for only one year, until the summer of 2005. If they take electricity supply service from their local utility after the summer of 2005, their *only* standard offer service option will be an hourly priced service based upon locational marginal prices ("LMP") in the PJM Interconnection.

For a perspective on the level of the standard offer service electricity supply rates for larger industrial customers in Maryland pursuant to its wholesale bidding procedure, one can assume an industrial customer with an 88% load factor, with a demand above 600 kW, which takes service at primary voltage and uses 50% of its energy during on peak hours and 50% during off peak hours. Such a customer of Delmarva Power, for example, would pay an average of 6.909¢ per kWh for electricity supply, which includes generation, transmission, and ancillary services – that is everything but distribution service. In addition, such a customer must pay an "administrative charge" for receiving the standard offer electricity supply service. The charge is 0.65¢ per kWh.

In comparison, a similar Virginia Power customer presently would pay 4.057¢ per kWh, on average, for electricity supply service (generation, transmission, and ancillary services – that is, everything but distribution service) under capped rates. If such a customer were required to pay 6.909¢ per kWh for electricity supply service (and assuming it were required to pay no "administrative charge"), its rate would increase 70% for electricity supply service and 67% for electricity service overall.

A similar customer of AEP in Virginia presently would pay 2.6184¢ per kWh on average for electricity supply service (including generation, transmission, and ancillary services – that is, everything but distribution service) and 2.8772¢ per kWh for all services, including distribution service, under capped rates. In contrast, a similar customer of Delmarva Power in Maryland would pay 6.909¢ per kWh for electricity supply service, or 4.2906¢ per kWh more than what a similar customer would pay AEP here. That is, the Maryland customer would pay 164% above what an AEP customer in Virginia would pay for electricity supply service and 140% above what that customer would pay in total rates.

Both Virginia Power and AEP propose to join PJM later this year. When such utilities are part of PJM, they will be part of the same PJM market and, presumably, market prices available in the service territories of AEP and Virginia Power will be similar to market prices in Maryland, which is also part of PJM.

The Staff of the Maryland Public Service Commission ("Maryland PSC Staff") filed a report, dated April 29, 2004, with the Maryland Public Service Commission describing the process and the results of the competitive wholesale procurement process used to determine prices for standard offer supply service at the end of Maryland's capped rate service. The Maryland PSC Staff found evidence of robust competition as shown by the large number of bidders, the large number of bids received, and a wide range of bid prices. The number of megawatts offered was nearly five times greater than the number of megawatts awarded. Of twenty five wholesale bidders, fourteen won contracts to provide some portion of the wholesale supply for full requirements service to Maryland customers who do not choose a competitive service provider.

The Maryland PSC Staff calculated the projected rate increases for residential and small commercial customers. Rates for standard offer power supply service for residential customers of PEPCO, for example, would increase 24% above capped rate power supply rates, and total bills (which include the distribution portion of the bill as well) would increase 15%. Residential customers of Delmarva Power in Maryland would see increases of 17% to pay for standard offer service power supply rates, as compared to capped rate power supply rates, and total bill increases of 11%.

In Virginia, retail customers of electric utilities may remain on their respective utility's capped rates through 2010, so they will not be forced to pay market prices prior to then.[1] If, however, customers in Virginia were forced to go to the market now, or if market prices in 2011 were similar to, or higher than, they apparently are now in PJM, it appears that, based on the wholesale bid prices in Maryland for standard offer service, customers in Virginia could see significant increases in their electricity costs. As suggested above, such increases for larger customers of Virginia Power might be on the order of 65% and for larger customers of AEP on the order of 140%.

The SCC and the General Assembly in Virginia should investigate Maryland's wholesale bid prices to assess their implications for Virginia's public policy of moving toward market based rates.

[1] The State Corporation Commission ("SCC") has the authority to terminate "capped rate" service prior to the end of 2010 if it determines that an effectively competitive market for generation services exists; however, in view of the progress of competition to-date and recent trends, such an SCC determination must be regarded as highly unlikely.

ATTACHMENT 3

Dominion: Capped rates equal profit

Gains of up to 7 percent a year expected under extension through 2010

BY GREG EDWARDS
TIMES-DISPATCH STAFF WRITER
Friday, May 7, 2004

Virginia's extended capped electricity rates should mean higher profit for Dominion Resources Inc., executives of the Richmond-based utility told Wall Street analysts yesterday.

The governor, attorney general and boosters including Dominion Virginia Power, a Dominion subsidiary, sold a 3½-year extension of capped electricity rates to the General Assembly this year as a way to protect consumers from the failure of electric deregulation to produce competition.

Virginians may be happy with the extension, which will keep electric base rates - which do not include overall rate adjustments for fuel, reliability and environmental costs - at their mid-1990s levels through 2010.

Dominion, however, should do well under capped rates, too, increasing profit from 5 percent to 7 percent a year, Dominion executives said.

Dominion can better increase its profit with frozen rates than it could under the old system of state-regulated rates, Chairman and CEO Thomas E. Capps said. "We've always made money when things freeze."

Thomas F. Farrell II, Dominion's president and chief operating officer, described the capped-rate extension as the last component needed for Dominion to become the most competitive and profitable integrated energy company in the country.

Dominion was earning an 11.5 percent return on shareholder equity in 1999 when rates were capped. It is earning 14 percent today because deregulation and capped rates caused the company to become more efficient and improve service, Farrell said. Uncertainty about rates has been eliminated through 2011, he said.

The capped-rate extension legislation also froze until mid-2007 the amount of power-plant fuel costs that Virginia Power can pass along to its customers. Fuel rates are frozen at $17.56 per megawatt hour, an all-time high, and any fuel savings boosts the bottom line.

Farrell enumerated several potential areas for savings. Dominion can reduce its costs for coal, which makes up 46 percent of its fuel costs, by negotiating favorable long-term contracts. The company can also increase the service time of its nuclear units from 91 percent to as much as 96 percent, which could add $20 million to earnings next year, he said.

Virginia Power - with no capital investment required - is making software changes in the way voltage is managed that could save up to $4 million a year by reducing the power lost through the transmission system, Farrell said.

Dominion is looking at up to $9 million in additional revenue from oil and coal sales at Tidewater facilities, and will use earnings from its oil and gas exploration and production business to offset increases in the cost of fuel to generate electricity.

Virginia Power has cut by $160 million the annual amount it pays to independent power plants but still has contracts with independents that cost $580 million yearly. Since the passage of this year's legislation, the company has never been more active in cutting those costs, Farrell said.

Dominion will not see a higher profit until next year. This year, it expects less profit because of the frozen fuel rate. The company took a $20 million loss on unrecoverable fuel costs in the first three months of 2004 and expects to lose millions more on fuel through the rest of this year.

Farrell described the capped-rate law as a win for consumers and an opportunity, but no guarantee, for Dominion to increase profit. "We must perform," he said.

He said the company is not concerned about electric competition developing in Virginia and hopes it does.

Capps, responding to a question, said he does not expect the state legislature to change or reverse deregulation or seek a rate cut for power companies. Lawmakers have tried and failed before, and the legislature has been solidly behind competition for nearly a decade, he said.

It would take a big number of Virginians calling up their lawmakers to force a change in the law, he said. "That ain't going to happen," he said. "Nobody in Virginia is picking up the phone, writing a letter or sending e-mails complaining about electric rates because they've been flat since 1992."

In answer to another question, Capps indicated that Dominion may increase its dividend this fall. The dividend has not been raised in roughly a decade, but Capps indicated that Dominion's cash-flow situation may allow an increase.

Contact Greg Edwards at (804) 649-6390 or gedwards@timesdispatch.com

This story can be found at: http://www.timesdispatch.com/servlet/Satellite?pagename=RTD%2FMGArticle%2FRTD_BasicArticle&c=MGArticle&cid=1031775316397&path=%21business&s=1045855934855

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Dominion®

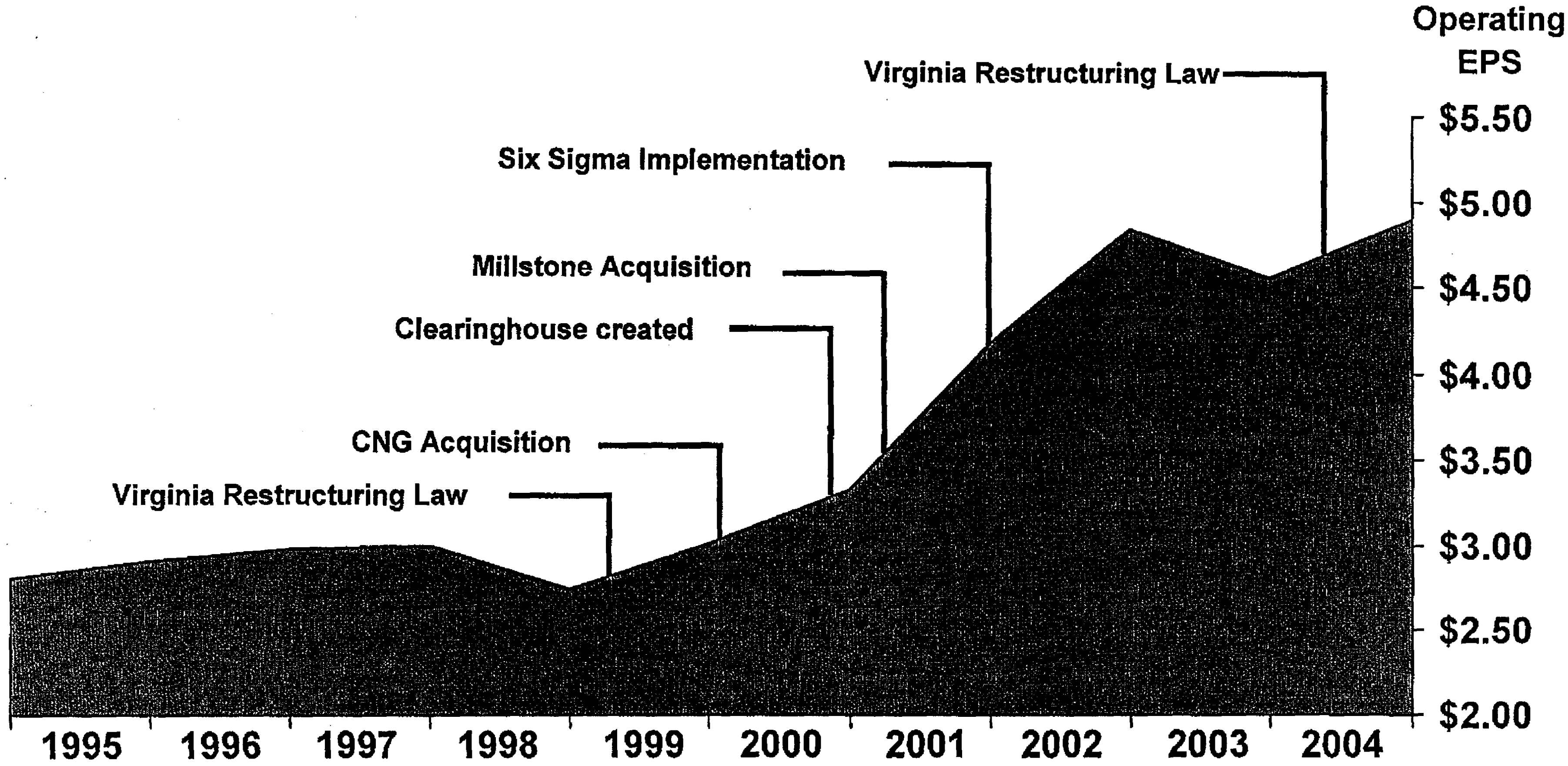
Spring 2004 Analyst Meeting

Update on Electric Deregulation in Virginia - SB 651

New York

May 6, 2004

Dominion's Got What it Takes



Dominion has consistently demonstrated earnings growth by building a balanced portfolio and developing competencies in operational, financial and risk management excellence. The latest Virginia Restructuring Law is one more piece of the strategic puzzle.

Dominion

Note: For a reconciliation of GAAP to non-GAAP financial measures, please go to our website at www.dom.com/investors under "GAAP Reconciliation".

Performance & Stability

- SB 651 opens doors to increased earnings
- The Rate Cap extension provides revenue certainty for additional 3 1/2 years
- Fixed fuel factor lowers Dominion's consolidated risk profile

ATTACHMENT 4

Dominion Virginia Power's Request to Defer $280 Million of RTO Costs Until 2011

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

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

Further, DVP states: "Given that RTOs provide significant customer benefits, it is appropriate for such customers to bear the associated costs of developing and participating in an RTO."[3] This statement is inconsistent, however, with the fact that "capped" base rates and frozen fuel rates prevent DVP's customers from receiving benefits from DVP joining the RTO, *i.e.*, benefits resulting from reduced fuel costs or avoidance of the need to build new generating units. With "capped" based rates and frozen fuel rates, DVP's shareholders, not it customers, will receive such benefits.

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

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1 Joint Application at 20.
2 Joint Application at 21, fn. 45.
3 Joint Application at 19.

ATTACHMENT 5

Presentation of Jeff Pollock
on behalf of the
Virginia Committee for Fair Utility Rates
and the
Old Dominion Committee for Fair Utility Rates
before the
Commission on Electric Utility Restructuring
November 24, 2003

Introduction

- Jeff Pollock is a principal with BAI (Brubaker & Associates). In his 29 years of practice in the utility industry, Mr. Pollock has participated in regulatory issues both in Virginia and in 19 other states, primarily in the southeast. He is especially active in Texas, which thus far has the most successful retail customer choice program in the nation.
- Mr. Pollock's firm, BAI, has been active in regulatory and legislative matters in many other states across the country. BAI has participated in or assisted over 30 other customer groups similar to the Old Dominion Committee for Fair Utility Rates (ODCFUR) and the Virginia Committee for Fair Utility Rates (VCFUR) in transitioning from regulation to customer choice.
- The Committees have retained BAI to render an opinion whether Appalachian Power Company (APCo) and Dominion Virginia Power Company (DVP) have stranded costs.
- As Mr. Pollock will explain, the short answer in both cases is a resounding NO!

Summary

- The purpose of our analysis is to determine whether APCo or DVP have stranded costs as a result of allowing retail competition. Our analysis reveals that neither

APCo nor DVP have stranded costs. Using a methodology first developed by Moody's Investors Service, a highly reputed firm that specializes in rating bonds and other securities, we have calculated that APCo would have $874 million of stranded benefits. Coupled with other evidence, we conclude that APCo does not have stranded costs.

- We obtained a similar result for DVP - $1.2 billion of stranded benefits – under the Moody's methodology. This study, coupled with the more detailed asset valuation presented to the State Corporation Commission and intervening changes, has led us to conclude that DVP does not have stranded costs.
- These results are based on the same 2003 market prices used by DVP and APCo and approved by the State Corporation Commission to set wires charges.
- We know that projected market prices for 2004 are significantly higher. Using these significantly higher market prices, stranded benefits would increase still further.
- Asset valuation is the appropriate method of administratively quantifying stranded costs. This was the approach used by DVP in a 1997 regulatory proceeding and used by VCFUR and the Attorney General in 1998. Further, the SCC Staff has recommended asset valuation. The Moody's methodology is another example of an asset valuation and it provides a "snapshot" of stranded costs.
- DVP's proposed method for quantifying stranded costs fails because, unlike an asset valuation, it doesn't compare book value with the market value of its generating assets over their remaining useful lives.
- Before elaborating further about our conclusions, allow me put our analysis in perspective.

Background on Stranded Cost

- The stranded cost debate arises in those states allowing retail customers to choose their electricity supplier. Stranded costs are *revealed* by retail competition because if customers can choose an alternative electricity supplier, the former regulated utility *might* not be able to fully recover the prudently incurred investments that it made under regulation.
- This is consistent with the definition of stranded costs in the State Corporation Commission's July 2003 Report to the Commission on Electric Utility Restructuring of the Virginia General Assembly, which I have adopted. Specifically, stranded cost is defined as the utility's net loss in economic value arising from electric generation-related costs that become unrecoverable due to restructuring and retail competition.
- In other words, unless customers switch from their current regulated suppliers, stranded costs are zero. Without suppliers vigorously competing for retail business, there can be no competition, and without competition, there can be no customer choice, and therefore, no stranded costs.
- In Virginia, to date, only very few customers have switched suppliers. Therefore, even though current law allows retail competition for all customers, no costs have been stranded. Despite this fact, DVP has been allowed to accumulate hundreds of millions of dollars in excess earnings for the sole purpose of stranded cost recovery.
- The irony here is that the longer it takes before all retail customers switch suppliers, the less likely a utility will incur stranded costs. At the earliest, significant switching will not begin until July 1, 2007, when wires charges expire and all customers must pay market prices.

Definition and Quantification of Stranded Cost

- As mentioned previously, BAI has been involved in many states during the transition from regulation to customer choice. Although each state has approached the stranded cost issue somewhat differently, we have learned that there are appropriate and reasonable methods of quantifying stranded costs.
- Though concerns have been raised that quantifying stranded costs requires making assumptions, many of the key variables used in a conventional asset valuation can be fully vetted. For this reason, regulators in customer choice states have been empowered to determine stranded costs for their regulated utilities in contested proceedings. The good news is that the SCC need not begin from scratch. There is a wealth of experience and regulatory precedent that can be used to quantify stranded costs in the Commonwealth.
- First, we can agree that stranded cost is the difference between the regulatory book value and the corresponding market value of a utility's generation fleet. If the market value exceeds book value, then a utility is said to have stranded benefits.
- Second, determining book value is relatively easy. The more challenging task is quantifying the market value. This process is no different in principle from a conventional asset valuation. Asset valuation is widely used by appraisers, financial analysts, investors, and consumers.
- Asset valuation is not rocket science. In an asset valuation, we calculate the net present value of the free cash flows (that is, future revenues less future cash expenses) derived from the use of the assets over their remaining useful lives.

- DVP used similar valuation techniques in the "Transition Cost Report," which it filed with the SCC in 1997. DVP is also using these techniques to conduct asset impairment tests for financial reporting purposes.
- The Moody's approach to valuing utility assets and determining whether a utility is likely to have stranded costs, which I have used in my analysis presented here, is an excellent example of a simplified, but reasonably accurate, asset valuation technique. It is a snapshot based on current conditions.
- The "Moody's" methodology uses publicly available data to determine whether the regulatory net book value of generation assets can be sustained in a competitive market environment. The analysis also takes into account reported payments made to independent third parties for purchased power and any remaining regulatory assets.
- Using the Moody's methodology, we calculated that APCo and DVP would have stranded benefits of $874 million and $1.2 billion, respectively. There is, however, other evidence to support our conclusions that neither utility has stranded costs.

<u>APCo</u>

- First, with respect to APCo, not only does APCo enjoy very low rates, APCo has not asked the SCC to implement a wires charge under the Act.
- APCo's rates are the lowest for industrial customers in the southeast. A recent BAI survey of industrial electricity rates revealed that APCo ranks 28th out of 30 utilities in the Southeast, where 1 is most expensive and 30 is the least expensive. The survey includes investor-owned utilities and the TVA.

- Wires charges, along with capped generation rates, are the tools through which utilities are allowed stranded cost recovery under the Act.
- A wires charge is the amount of revenue that APCo would lose if customers were to switch suppliers. It is the difference between capped generation rates and the current market price.
- A zero wires charge means that market prices are higher than the capped rates. In other words, there are no stranded costs, only stranded benefits for APCo.

DVP

- The results we obtained for DVP comport with a prior study that was filed by DVP in a 1997 regulatory proceeding before the SCC. I am referring to the Transition Cost Report.
- The Transition Cost Report was an in-depth and detailed asset valuation. DVP determined the market value of its entire generation fleet, along with its substantial NUG purchases, to quantify potentially stranded costs. Based on its analysis, DVP contended that it would have $2.5 billion of potentially stranded costs.
- BAI conducted an in-depth analysis of the DVP study and in particular the underlying assumptions. We were very impressed with the detail and thoroughness of the study. DVP's asset valuation study estimated the free cash flows from the generation fleet operating in fully competitive markets through 2015. It was in nearly all respects a bona fide asset valuation.
- One of DVP's key assumptions was that competitive suppliers would serve all customers on January 1, 2003 – a fact we know today to be wrong. Ignoring this obvious hindsight, our analysis revealed several major flaws.

- Correcting only two of these flaws, and using DVP's method otherwise, my firm determined that DVP would have $2.7 billion of stranded benefits.
- The two major flaws that we corrected to arrive at the opposite conclusion as DVP were:
  - Employing a cut-off date of 2035, rather than 2015, to recognize the fact DVP's generation fleet will have many years of useful life beyond 2015.
  - Using a capacity value that would encourage competition.
- By prematurely cutting off the study at 2015, DVP failed to fully capture the much greater market value of its generating assets during a period when they would generate the most profit.
- Undervaluing capacity means understating the cost of maintaining reliability. We would all agree that maintaining reliability is critical regardless of the regulatory environment.
- Despite the 1997 vintage of the DVP study and our two corrections to it, the conclusions would be the same if a similar study were conducted today – DVP has no stranded costs. Consider the following:
  - Market prices for electricity are much higher than the Company assumed due to higher natural gas prices. This increases the market value of DVP's generation fleet, thereby reducing any potential stranded costs and increasing stranded benefits.
  - DVP has extended the lives of its nuclear plants by 20 years. This will reduce costs under capped generation rates (due to lower depreciation expense). Further, the Company will be able to profit handsomely in competitive markets

because the operating cost of a nuclear plant is 15% or less of the wholesale market price of electricity. This would further increase stranded benefits.

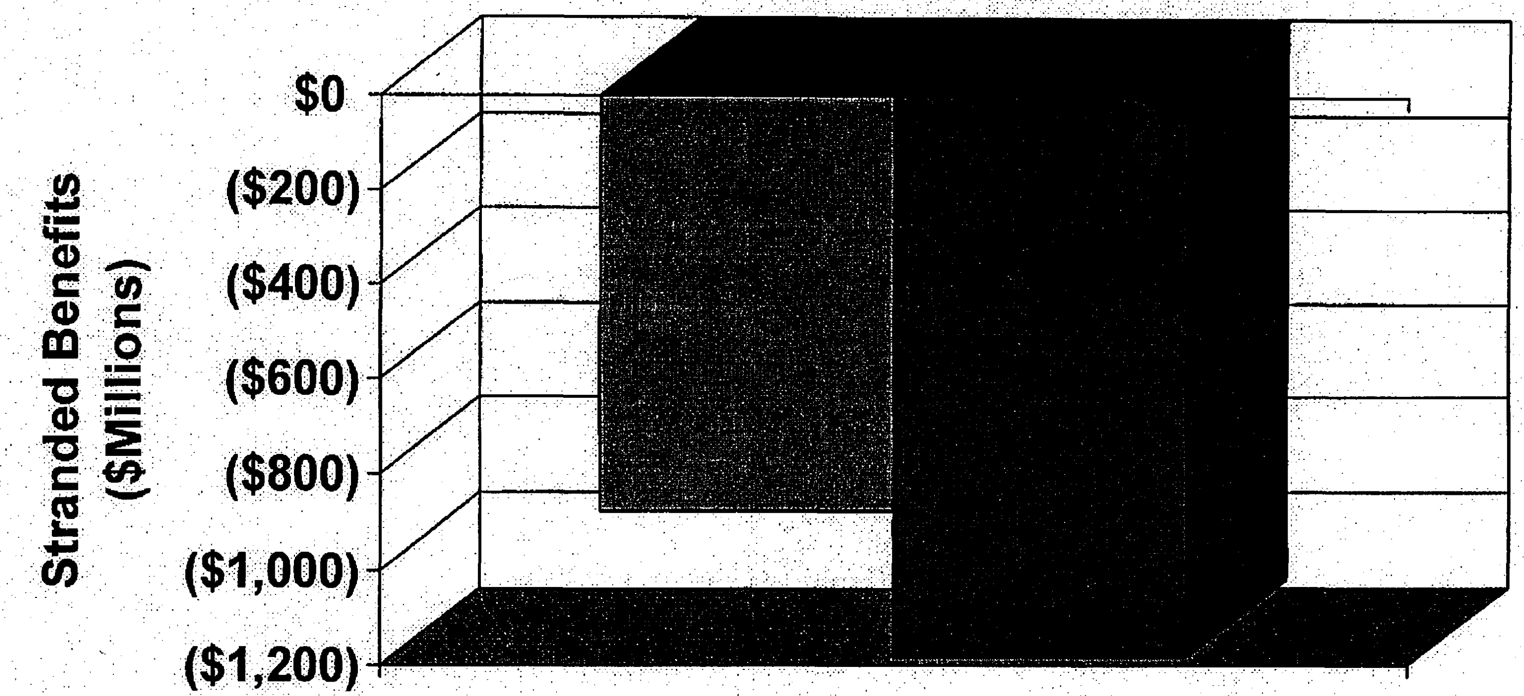
  - The Company has renegotiated several of its NUG contracts, and several contracts have expired since 1998. As a result of the passage of time, the Company's commitment under purchased power contracts is about $1 billion lower on a net present value basis.

- Finally, as I previously stated, DVP is using asset valuation techniques for financial reporting purposes to determine whether it will have to write-off investment or recognize losses under its purchased power contracts. Thus far, the Company has not had to write down any plant investment or recognize any contract losses. In essence, the Company is conceding, based on its own assessment of future market prices, that it has no stranded costs.

Stranded Cost Summary

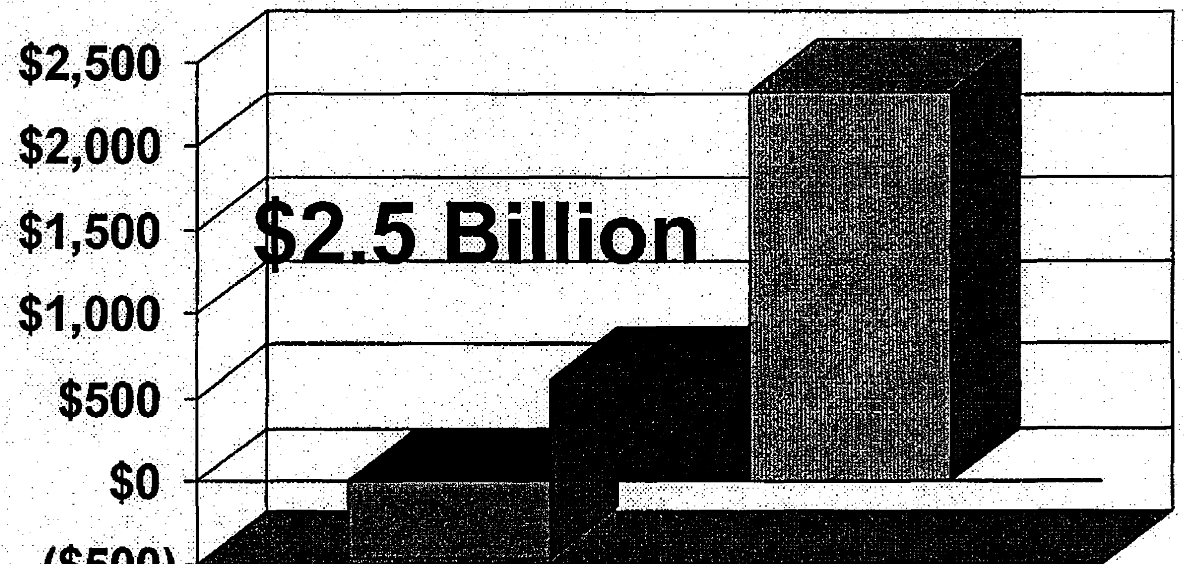
- **No evidence that either APCo or DVP have stranded costs**
- **Asset valuation is the appropriate methodology**
  - Used by DVP in 1997 ($2.5 Billion stranded cost)
  - Used by Attorney General in 1998 ($1.3 Billion stranded benefits)
  - Used by VCFUR in 1998 ($2.7 Billion stranded benefits)
  - Recommended by the SCC Staff
  - Used by Moody's ("snapshot")

Estimated Stranded Costs Using Moody's Methodology



APCo	($874)
DVP	($1,182)

1997 Transition Cost Report
DVP Analysis



	Transition Cost Report
Fossil & Hydro	($463)
Nuclear	$608
NUG Contracts	$2,322

BAI

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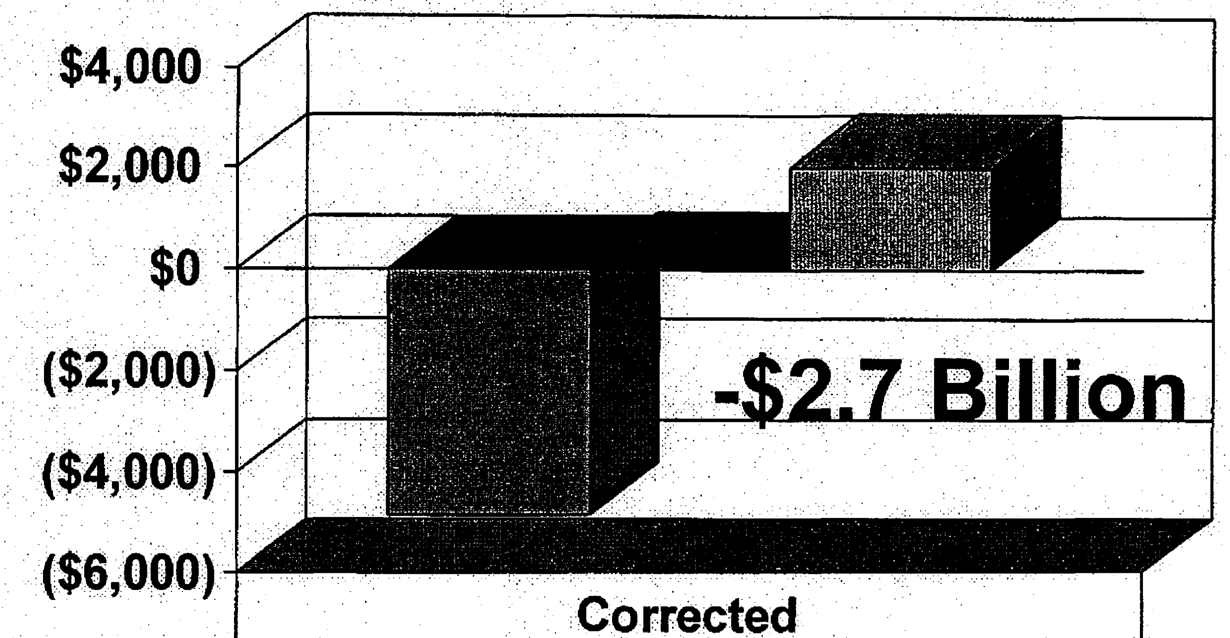
Estimated Stranded Costs (Benefits) With VCFUR Corrections



	Corrected
Fossil & Hydro	($4,855)
Nuclear	$102
NUG Contracts	$2,032

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May 24, 2004

David Eichenlaub
Assistant Director, Finance
State Corporation Commission
1300 E. Main Street
Richmond, VA 23218

Response of PJM Interconnection, L.L.C. to the Virginia State Corporation Commission's April 26, 2004 Request for Market Participant Comments on the 2004 Report to the Commission on Electric Utility Restructuring

Dear Mr. Eichenlaub:

PJM Interconnection, L.L.C. ("PJM") is pleased to provide these comments in connection with staff's review of the status of electric restructuring in the Commonwealth.

The electric restructuring legislation enacted by the General Assembly has recognized the importance of a strong regional transmission organization ("RTO") in the Commonwealth. PJM believes it is well-suited to meeting the General Assembly's requirements. PJM has over 75 years of experience in regional coordination and centralized security-constrained dispatch to balance the output of a wide variety of electric generating resources with load. Since 1997, PJM has served as an independent entity that both ensures the reliability of the electric power grid and operates a competitive wholesale market. Indeed, the SCC was one of the original signatories to a Memorandum of Understanding between PJM's Board and its state regulatory commissions, and was one of the founding members involved in the formation of PJM as an independent transmission grid operator.

The critical test of the suitability of any RTO is the test of use. Since its inception, PJM has met or exceeded all applicable NERC reliability criteria. Since 1999 and in conjunction with PJM's regional planning process over 10,000 MW of new generation has been placed in service and over 15,000 MW of additional generation is currently being studied. Approximately $700 million of transmission upgrades have been approved by the Board of Managers, including $100 million in investment on the Delmarva Peninsula. These substantial additions to the bulk power facilities in PJM increase reliability and contribute to a robust wholesale market. PJM has seen a five year decline in the forced outage rate of generators, reflecting a trend toward greater efficiency. As proven with the integration into PJM of Allegheny Power and Commonwealth Edison, the PJM model can be introduced readily into regions that were not part of PJM's original power pool and that are served by other reliability councils. The integration of Allegheny Power into PJM enabled it to save over $40 million in an initial eight month period as a result of its full participation in PJM's regional energy market.

PJM believes that the integration of Dominion and Appalachian Power into PJM will provide a solid foundation for the SCC's ongoing efforts to implement the restructuring statutes of the Commonwealth. As one large entity with many resources and tools at its disposal, PJM is able to "see the big picture" and take appropriate action to address reliability issues in real time and prospectively. As a result, the integration of Virginia's utilities into PJM will enhance reliability in the Commonwealth. The August 14, 2003 event in the Midwest proved the need for such an entity to monitor the grid and take necessary remedial action before problems cascade.[1]

PJM is keenly aware of the Commission's perception that it may lose jurisdiction if the electric utilities it regulates join PJM. In fact, the SCC will retain ultimate retail ratemaking authority, and in other respects its ability to exercise its jurisdiction will be enhanced. Because PJM's markets are voluntary, Virginia electric utilities will have the option to self-schedule their load employing their lowest-cost resources, to arrange for bilateral transactions, or to rely as is appropriate on the PJM LMP-based energy market. These options provide assurance that Virginia native load will be protected from higher prices elsewhere, as the Commission's enhanced access to the cost information provided by the marketplace provides a basis for regulators to assess the reasonableness of default service pricing.

From a planning perspective, the Commission will retain its siting authority while enjoying access to more comprehensive and robust information developed in PJM's regional planning process. Both AEP and PJM have identified a number of points on our respective systems where congestion could better be addressed through a regional planning process (*see* the testimony of AEP witness Craig Baker in Case No. PUE-2000-00550.) In many cases, the "fix" for transmission problems might be an upgrade that is beyond the SCC's authority to order as it involves upgrades in another state or on a system outside the SCC's jurisdiction. A regional planning process with active participation by the SCC would help assure that the appropriate upgrades are made, whether for reliability or economic considerations (or both), at the most reasonable cost.

PJM is committed to working with the SCC to ensure a successful restructuring of the industry in the Commonwealth. We attach to this document a copy of our 2003

[1] On August 14, 2003 PJM identified certain problems on the First Energy system which it communicated to First Energy and MISO, First Energy's reliability coordinator. Once the cascade began, PJM was able to isolate the PJM system to prevent the blackout from encroaching and spreading to the PJM region, Virginia, and the rest of the Eastern Interconnection. The facts demonstrate that a large entity with market tools and independence from market participants is best able to maintain reliability with such tools and established communication protocols.

Annual Report, as well as the PJM Market Monitor's State of the Market Report. We welcome further discussion of the issues raised in this submittal and look forward to working with you in the days and weeks to come.

Very truly yours,

/n/

Craig Glazer
Vice President—Government Policy

RESPONSE FROM PJM INTERCONNECTION, LLC

Although not reprinted here, the response from PJM Interconnection, LLC, included two attachments that may be found in its entirety at:

2003 PJM Annual Report:
http://www.pjm.com/about/downloads/pjm-web.pdf

2003 PJM State of the Market Report:
http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/pjm-som-2003.pdf