2002 Performance Review of Electric Power Markets

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Review Conducted for the Virginia State Corporation Commission*

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August 30, 2002

*This report was conducted by NRRI under contract with the Virginia State Corporation Commission as Part II (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.

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Introduction

The last two years of the electric supply industry have been, to put it mildly, eventful. Shortly after prices in California and the West had begun to subside, beginning in late 2001 news of Enron's difficulties and subsequent collapse, accounting improprieties in the industry, and a current "credit crunch" hit the industry. Also, the Federal Energy Regulatory Commission (FERC) has recently proposed new rules to standardize critical wholesale market practices. This is intended by FERC to facilitate wholesale market development and restore investor confidence, but will unavoidably require a transition period if adopted and will continue the industry's upheaval, at least temporarily. In the face of all this turmoil, while many retail markets remain relatively inactive, particularly for smaller residential customers, overall market activity has increased from last year. Wholesale markets since California settled down, continue in general to function well, although there continues to be strong evidence that significant market power is being exercised in all markets that have been examined. After a brief introduction, Section I reviews the performance of retail markets in all states (beside Virginia) that currently allow retail access. The second Section reviews the performance of wholesale markets in California, New England, PJM, and New York.

Measuring retail market performance

Wholesale market performance is discussed in Section II in terms of prices and how closely actual prices have been tracking what would occur in a fully competitive market.[2] 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 directly observable. The review of retail markets summarizes what we can

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[2] As is discussed in detail in the second Section, this means a negligible amount of market power is being exercised by suppliers, or that market prices are at the marginal cost of the marginal unit needed to serve electricity demand at that time period.

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 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 in the next part of this section, 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 and thus, seldom fluctuate along with changing conditions in the wholesale market or, when adjustments are made, 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.

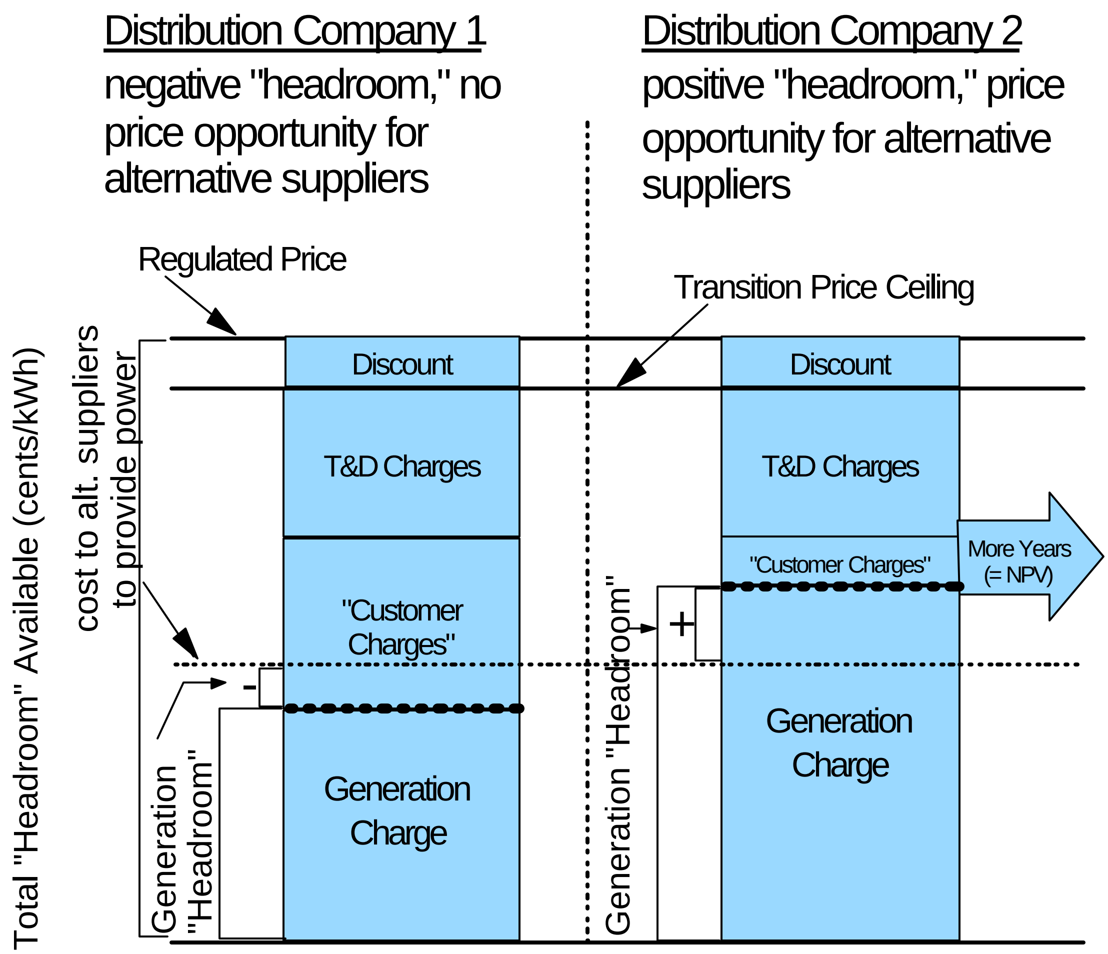

Figure 1. Examples of two different distribution companies with different generation cost and with the same cost of procuring power for alternative suppliers.

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 1, where the generation charge or price-to-compare is, relative to the cost to competitive suppliers to obtain or generate power, will determine the amount of "headroom" available for alternative suppliers to compete. The distribution companies in Figure 1 have the same beginning regulated price, discount,[3] 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[4]), 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 1, 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).[5] However, the headroom may be too small to cover all the

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

[4]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.

[5]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

costs of supplying the retail customers, be nonexistent, or even 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).[6] 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. As will be seen, this lack of headroom

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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.

[6]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.

is the primary reason that many retail markets currently have very little activity and, where there is retail market activity, it is primarily in states or distribution companies that were relatively higher cost before restructuring began. A numerical example of this effect is presented in Section II, in the discussion of the PJM wholesale market.

Section I: Status of Electric Retail Markets

This Section provides an overview of the status and activity of state restructuring and retail access. Specific states that share the general geographic region with Virginia are then briefly summarized and a more comprehensive look is taken of four states that have had considerably active retail markets and, consequently, are of particular interest: Maine, Ohio, Pennsylvania, and Texas. This is followed by a summary of activities in the remaining retail markets in other regions. Of particular interest to Virginia, may be the summaries of Texas and Michigan which began full retail access at the same time, January 1, 2002. Appendix A at the end of this report summarizes the retail market activity during May of this year in 17 states and the District of Columbia. This includes all states that currently allow retail access. Appendix B summarizes the expiration dates of the rate freezes and rate reductions in 14 states with retail access. There has been speculation that some of these rate caps may be extended beyond the current transition periods, depending on wholesale market developments and possible impact on retail customers.

Overview of State Electric Restructuring Activities

Currently, 17 states[7] and the District of Columbia allow retail access (see Figure 2). Four states that passed an electric restructuring law, however, have opted to delay restructuring. Arkansas, New Mexico, Oklahoma, and West Virginia have decided to delay or postpone retail access at this time, either pending further investigation or other action. West Virginia had planned a long transition period to full retail access, but has not proceeded to implement its restructuring law and is not expected to soon. Nevada and Oregon allow retail access for large customers only and California, which of course allowed retail access at one time, suspended its program in September of 2001.

[7] Arizona,Connecticut,Delaware,Illinois,Maine,Maryland,Massachusetts,Montana, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, Virginia.

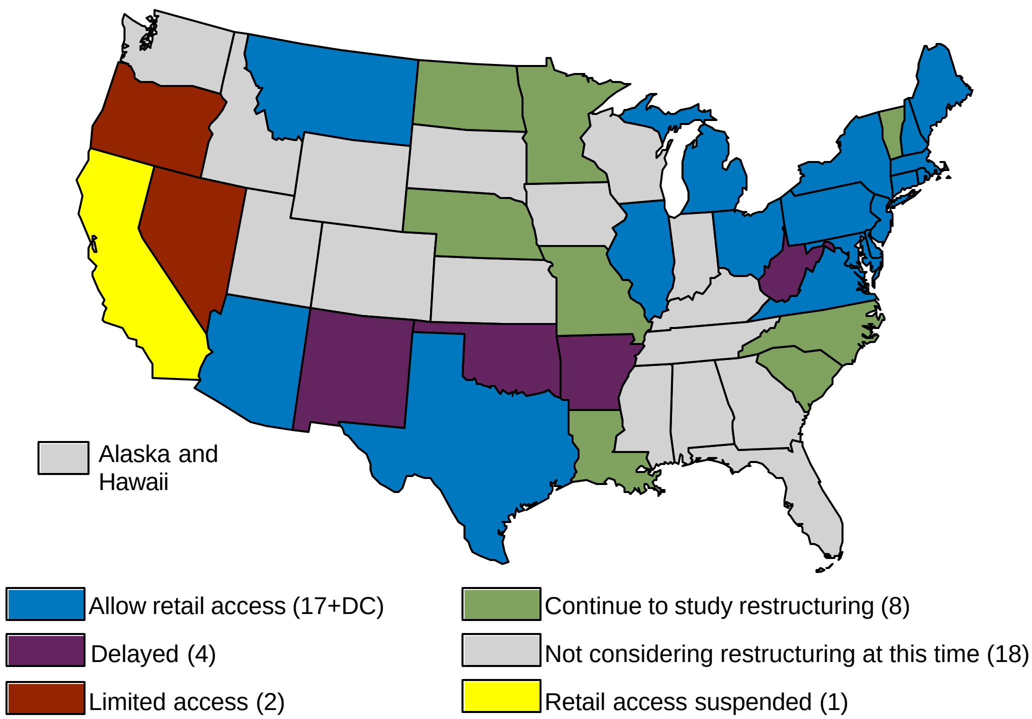

Figure 2. Current status of retail restructuring by state.
Source: NRRI survey, July 2002.

While the issues and motives may differ in each of these states that have delayed, suspended, or allowed retail access only on a limited basis, in general these states believe that the delay would allow them time to observe how restructuring states are doing and plan accordingly.

The California crisis has only made those states that had declined to move toward electric restructuring in the first place even more reluctant to move from their original positions. This group of states generally believes that they have little to benefit from opening their electric industries to competition anytime soon, since most of these states have relatively low electric rates compared with the rest of the nation. In total, 18 states[8] have decided that electric restructuring is not in their best interest at this time and are currently no longer actively considering it. At one time, before the California meltdown, every state in the nation was at least studying the issue–as eight states[9] continue to do. No state has passed restructuring legislation since California's problems began during the summer of 2000 and no state at this time appears to be close to doing so. However, several states that passed legislation prior to the California crisis did proceed with implementation. This included Arizona and Ohio in January 2001 and, along with Virginia, Michigan and Texas in January of this year.

Figure 3 shows that, nationwide, retail activity this year has picked up considerably since last year. As Figure 4 shows, a substantial portion of that increase was due to Texas beginning its full retail access program. The total number of residential offers below the price-to-compare increased from nine in July of 2001 to 44 in May of 2002, however, 29 of those offers were in Texas alone. Excluding Texas the number of offers increased from nine in July of 2001 to 15 in May of 2002 and the number of distribution company service territories with offers below the price to compare increased from eight to 11 during the same period.

A recent report estimated that 36,000 MW are currently being supplied by competitive suppliers, versus the estimated 15,000 MW one year ago, or 2.2 million customers versus 1.4 million customers in 2001. Of the 36,000 MW switched, the report indicated 11,000 MW was in Texas. The four states of Illinois, California, New York, and Ohio each had more than 3,000 MW of load switching.[10] This means that nearly two-thirds

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[8]Alabama, Alaska, Colorado, Florida, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Mississippi, South Dakota, Tennessee, Utah, Washington, Wisconsin, Wyoming.

[9]Louisiana, Minnesota, Missouri, Nebraska, North Carolina, North Dakota, South Carolina, Vermont.

[10]Business Wire, "New Xenergy Research Finds Retail Electric Competition Alive and Well; 36,000 Megawatts Now Served Competitively in the U.S.," August 22, 2002. As noted,

of the total load that has switched in the U.S. to alternative suppliers is in these five states. These are states, or states that have distribution companies within the state, that had relatively higher rates before restructuring began.

Seven states and the District of Columbia have at least one distribution company with at least one offer below the price-to-compare. These are Connecticut, the District of Columbia, Maine, Maryland, New York, Ohio, Pennsylvania, and Texas. These states are discussed in more detail below. Appendix A summarizes the May 2002 offers for all states that allow retail access.

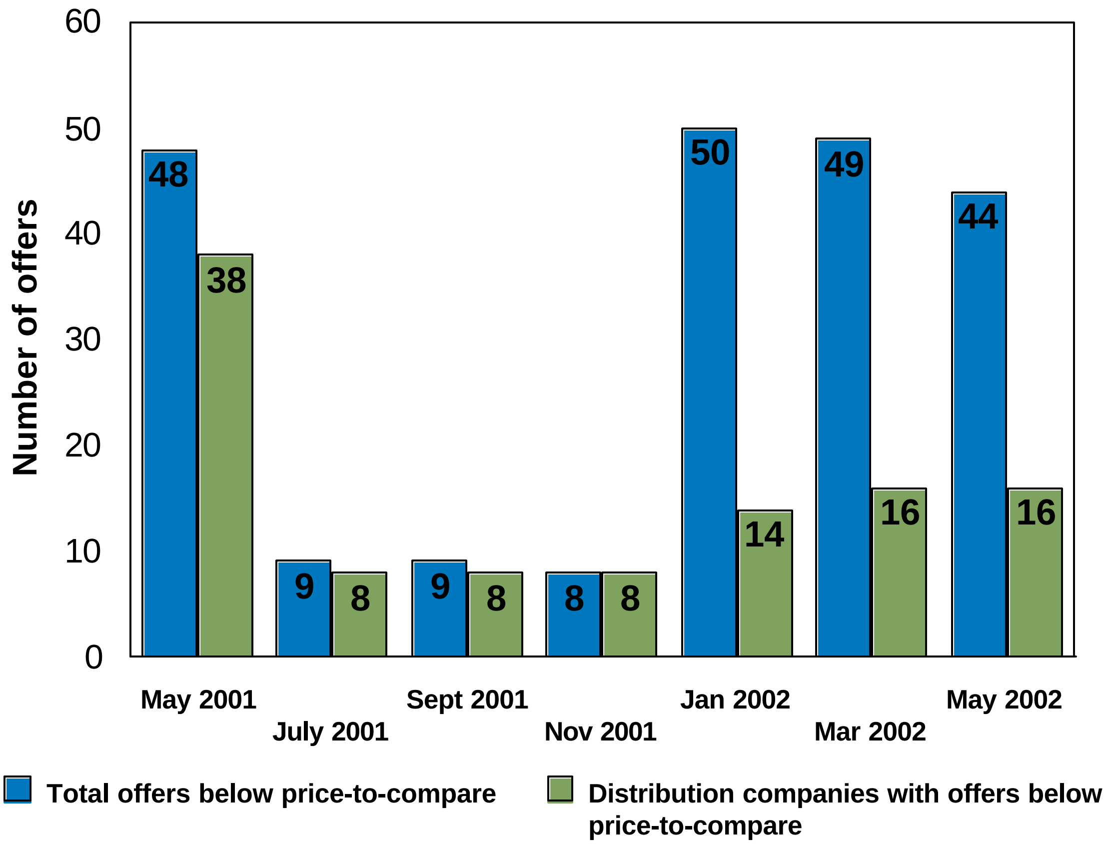

Figure 3. Residential offers nationwide.
Source: www.wattagemonitor.com.

California has suspended its retail access program, however, customers that had selected an alternative supplier before the suspension are allowed to remain with their chosen supplier.

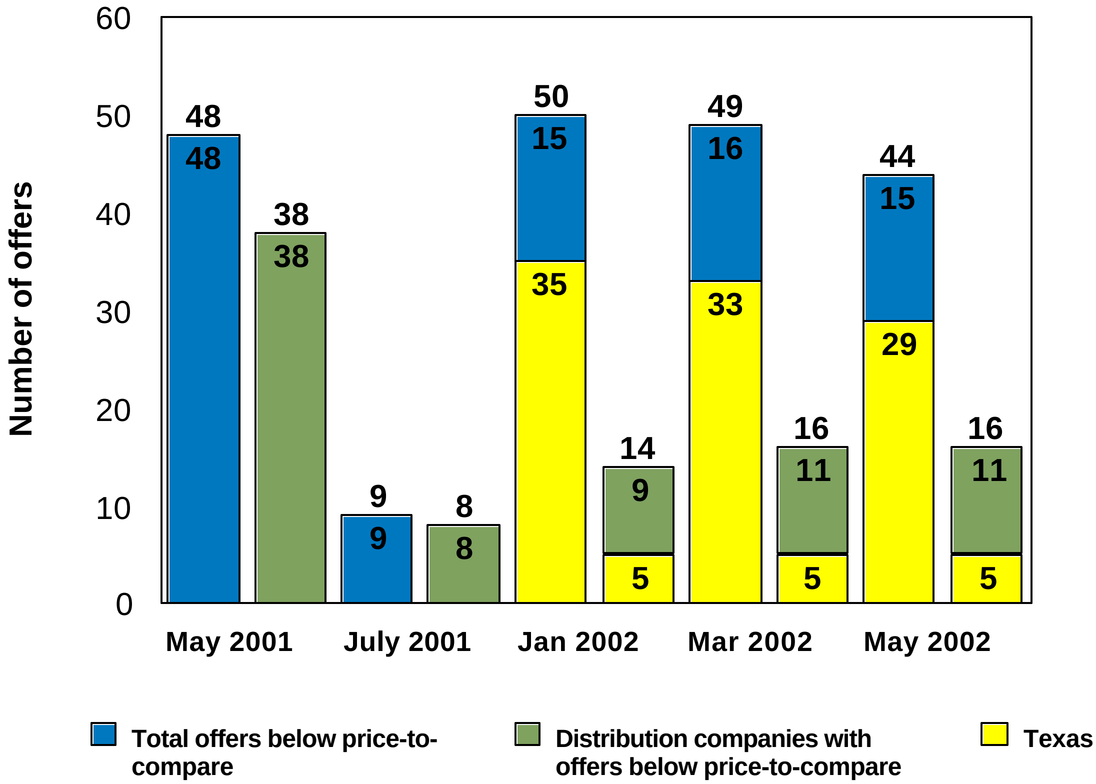

Figure 4. Residential offers nationwide with Texas shown separately
Source: www.wattagemonitor.com.

It should be noted that the source for the residential offers used throughout this section, www.wattagemonitor.com, is no longer in operation. The May 2002 data was the last obtained from this source.

Summary of Electric Restructuring Activity in the Mid-Atlantic Region

DELAWARE

Retail choice started in Delaware in October, 1999, but very few customers have switched. There were offers made by Allegheny Energy to Connectiv residential customers during the contract periods of January to May 2001 and from January 2002 to March 2002. Currently there are no suppliers offering a choice to residential customers. Connectiv has a total of 275,814 customers, comprising 246,051 residential and 29,763 non-residential customers. Out of these, only five non-residential customers with a capacity obligation of 119,503 kW are currently served by competitive suppliers.

Delaware Electric Cooperative also has no suppliers offering alternative supply service in its service area at this time. The cooperative had renewable offers from Sterling Planet during March to May 2001 and had a competitive price offer from ServiSense in May 2001. They have a total of 58,829 customers: 53,733 residential and 5,096 non-residential. Currently, no Delaware Electric Cooperative customer has selected an alternative supplier.

DISTRICT OF COLUMBIA

In the District of Columbia, the total number of residential customers who have switched has gone up from 1,404 in September 2001 to 11,287 in June 2002. This is 5.8 percent of the residential customers and 7.1 percent of total electricity. The total number of non-residential customers who have switched has also gone up from 4,295 in September 2001 to 5,227 in June 2002, which is 19.5 percent of the total number of customers. Alternative electric suppliers account for 56.7 percent of the total consumption by the non-residential sector. An offer to residential customers from Washington Gas Energy Services since September 2001 provides savings of three percent off PEPCO service rates for winter and six percent off summer rates. PEPCO Energy Service also provides services with rates lower than PEPCO's Standard Offer Service rates. These likely contributed to the large increase in the customers choosing an alternative supplier.

MARYLAND

Maryland's residential market had relatively fewer offers since March 2001. There are some offers to residential customers in the service area of Potomac Electric Power (PEPCO) since March 2002 and in Baltimore Gas and Light (BGE) since May 2002.

Less than one percent of residential customers purchase their generation from an alternative supplier in the Allegheny Power (AP), Connectiv Power Delivery (Connectiv) and BGE service territories. In the Connectiv and AP areas, no residential customers are served by competitive suppliers. In BGE's area twelve residential customers are served by an alternative supplier. PEPCO is the most active retail market at this time in Maryland with 58,572 accounts representing thirteen percent of the total accounts being served by competitive suppliers. The number of customers buying from suppliers has increased steadily over the past two years. In PEPCO's area, 238 MW (14.5 percent of the residential peak load obligation) is served by alternative suppliers. Over all, about 3.2 percent of Maryland residential customer accounts (4.18 percent of peak residential load) are served by competitive suppliers. Table 1 shows the percentage of residential customers who have chosen an alternative supplier in Maryland.

Table 1. Summary of Maryland residential retail electric switch rates (percent customers)

Month	Allegheny	Baltimore	Connectiv	Potomac	State Total
Sep-00	0	0	0	0.1	0.0
Oct-00	0	0	0	1.0	0.2
Jan-01	0	0	0	2.5	0.6
Apr-01	0	0	0	5.6	1.3
Jul-01	0	0	0	9.6	2.3
Oct-01	0	0	0	10.9	2.6
Jan-02	0	0	0	11.0	2.6
Apr-02	0	0	0	12.0	2.9
Jun-02	0	0	0	13.0	3.2

Source: Complied with data from Maryland Public Service Commission Website

Table 2 shows the percentage of non-residential accounts served by competitive suppliers. In almost all areas of the state, competitive suppliers provide service to some non-residential customers. AP has two accounts, BGE has 628 accounts, Connectiv has 163 accounts and PEPCO has 11,465 accounts served by competitive suppliers. Suppliers serve less than one percent of non-residential load in the APS service territory. PEPCO load served by suppliers has increased steadily since choice began. As of June 2002, 24.7 percent of the non-residential PEPCO customer accounts, using 47.1 percent of the peak load, are served by competitive suppliers. Non-residential load served by suppliers has grown rapidly to 28 percent in BGE's area, as frozen generation rates for BGE's large commercial and industrial customers ended on June 30, 2002 and the default rate for their customers is now the spot market price plus a retail cost adder of seven mills.[11] Connectiv load served by suppliers peaked in December 2001 at 12.8 percent. This has declined to seven percent in June 2002 as suppliers returned load to Connectiv, as they did in the summer of 2001. Alternative suppliers may again pick up that load as summer congestion prices decline. In the entire state, 5.8 percent of the non-residential customers with 27.6 percent of peak load are served by competitive suppliers.

[11] Part III of this report "Recommendations to facilitate effective competition in Commonwealth."

Table 2. Summary of Maryland non-residential retail electric switch rates (percent customers)

Month	Allegheny	Baltimore	Connectiv	Potomac	State Total
Sep-00	0.1	0.1	0.1	0.0	0.1
Oct-00	0.1	0.1	0.1	0.2	0.1
Jan-01	0.2	0.3	0.2	4.4	1.2
Apr-01	0.1	0.3	0.1	6.9	1.7
Jul-01	0.0	0.2	0.0	11.9	2.8
Oct-01	0.0	0.2	0.7	14.9	3.5
Jan-02	0.0	0.2	0.8	19.0	4.4
Apr-02	0.0	0.3	0.8	23.7	5.5
Jun-02	0.0	0.6	0.7	24.7	5.8

Source: Compiled with data from Maryland Public Service Commission Website

Generation rates in Maryland restructuring settlements generally represent the estimated embedded cost of generation at the time the settlements were reached and approved by the Commission in 1999. It is likely that suppliers find it difficult to compete with AP transition generation rate levels because of AP's historically low generation costs. The Maryland Staff believes that the level of competition in the BGE service territory could be similar to PEPCO if it were not for the level of BGE's competitive transition charge which resulted in a lower price to compare.

The situation with Connectiv is more perplexing. Although Connectiv has the highest Standard Offer Service (SOS) rates for most customer classes in Maryland, it appears that higher congestion-related wholesale generation costs, and perhaps other market factors as well, have prevented any competition for the residential market and limited competition in the non-residential market.

PEPCO has a large and high profile market with dual-fuel sales opportunities in both Maryland and the District of Columbia because of retail gas choice. Transition SOS rates are close enough to market prices to encourage competition.

The Maryland Public Service Commission (MPSC) initiated a proceeding in December 2001, for the purpose of resolving how and at what price SOS or default generation service will be provided to customers after the current generation rate caps expire. The first caps on residential electricity prices in

Maryland in the PEPCO and Connectiv service territories are set to be removed in 2004.

Maryland passed a law that requires utilities in the state to conduct a study to track generation and emissions. The study will be submitted to the MPSC and the Department of the Environment on or before December 31, 2003, and then be updated and re-submitted on December 31, 2005. If, after a review of the report, the Department of Environment determines that the emissions levels impose a higher emission burden in the state than now exists, it will consult with the MPSC regarding the appropriateness and feasibility of requiring an air quality surcharge. The goal of the surcharge would be to protect Maryland's environment in connection with the implementation of customer choice of electricity providers.[12]

NEW JERSEY

Since retail access began in New Jersey, there has been a decline in the percentage of customers served by alternative suppliers. Table 3 shows the percentage of customers who have switched to alternative suppliers. Currently, in the entire state, only about 0.2 percent of residential customers and 0.1 percent of non-residential customers are served by an alternative supplier.

Table 3. Summary of customer switching in New Jersey (percent customers)

	Residential			Non-Residential		
	Nov-00	May-01	Jun-02	Nov-00	May-01	Jun-02
Connectiv	5.9	1.5	0.1	11.8	1.1	0.7
GPU	1.0	0.2	0.0	5.8	1.1	0.0
PSE&G	1.8	1.5	0.3	6.3	5.2	0.1
State Total	2.2	1.1	0.2	6.9	3.4	0.1

Source: Compiled with data from New Jersey Board of Public Utilities Website

There are no offers below the price-to-compare for residential customers in the service territories of any distribution company. The total number of offers to residential customers has also declined from eighteen in July 2000 to four in May

[12] EnergyCentral.com.

2002. Figure 5 shows a summary of offers to residential customers in New Jersey.

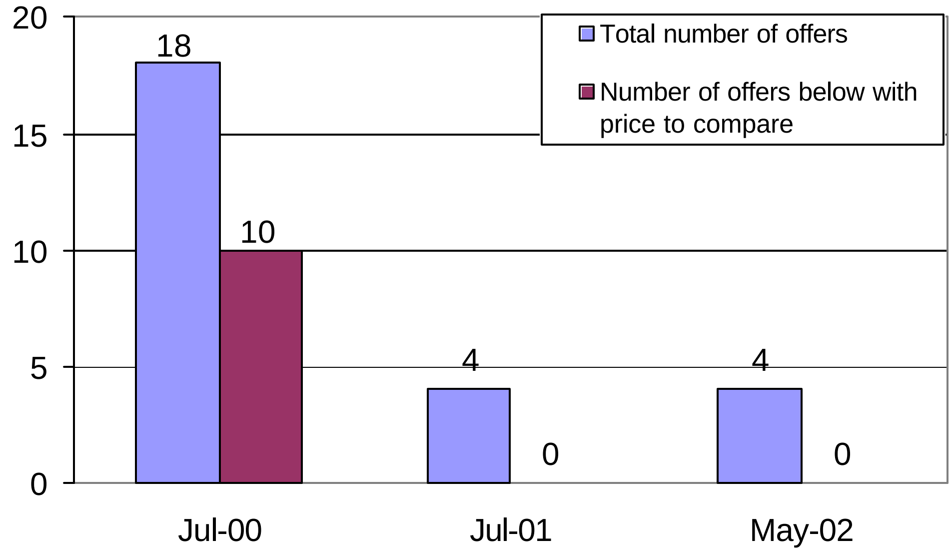

Figure 5. New Jersey statewide residential offers

Source: Compiled with data from www.wattagemonitor.com

Between September 2001 and May 2002, in the Public Service Electric and Gas Company (PSE&G) territory the generation price of electricity has gone down from 5.65 cents to 5.35 cents in November 2001 and then increased to 5.36 cents per kWh in January 2002. In GPU, it has declined from 6.63 cents in September 2001 to 5.21 cents in November 2001 and then gradually increased to 5.36 cents per kWh by May 2002. Connectiv Power Delivery (Connectiv) service territory has seen a continuous decline in the generation price. Table 4 shows a summary of the offers, generation prices and potential savings to customers who switch to alternative suppliers.

Table 4. Summary of New Jersey's residential retail electric offers

Public Service Electric and Gas Company	**Sep 2001**	**Nov 2001**	**Jan 2002**	**Mar 2002**	**May 2002**
Number of renewable offers	1	1	1	1	1
Number of variable offers	1	1	2	2	1
Total number of offers	2	2	3	3	2
Number of monthly contracts	1	1	2	2	1
No. of more than a year-long contracts	1	1	1	1	1
No.of offers below price to compare	0	0	0	0	0
Number of suppliers	2	2	3	3	2
Generation Price	5.65	5.35	5.36	5.36	5.36
Percentage savings on lowest offer	-	-	-	-	-
GPU/Jersey Central Power and Light	**Sep 2001**	**Nov 2001**	**Jan 2002**	**Mar 2002**	**May 2002**
Number of renewable offers	1	1	1	1	1
Number of variable offers	0	0	1	1	0
Total number of offers	1	1	2	2	1
Number of monthly contracts	1	1	2	2	1
No.of more than a year-long contracts	0	1	1	1	1
No.of offers below price to compare	0	0	0	0	0
Number of suppliers	1	1	2	2	1
Generation Price	6.63	5.21	5.31	5.31	5.36
Percentage savings on lowest offer	-	-	-	-	-
Connectiv	**Sep 2001**	**Nov 2001**	**Jan 2002**	**Mar 2002**	**May 2002**
Number of renewable offers	1	1	1	1	1
Number of variable offers	0	0	0	0	0
Total number of offers	1	1	1	1	1
Number of monthly contracts	1	1	1	1	1
No.of more than a year-long contracts	0	1	1	1	1
No.of offers below price to compare	1	1	0	0	0
Number of suppliers	1	1	1	1	1
Generation Price	7.02	7.02	6.78	6.29	6.29
Percentage savings on lowest offer	1.99%	1.99%	-	-	-

Source: Compiled with data from www.wattagemonitor.com

In February 2002, the New Jersey Board of Public Utilities (BPU) approved the results of a Basic Generation Service (BGS) auction to meet the electric demands 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 the restructuring law that utilities facilitate competition of the supply of electricity to customers who have not switched companies under deregulation. The auction set lower than expected prices for the utilities' BGS. GPU's price will be 4.87 cents per kWh compared to the customers' previous rate of 5.06 cents per kWh. Conectiv's price is set at 5.12 cents per kWh compared to its previous customer rate of 5.17 cents charged from January to August of last year. Because electricity consumers' rates are capped until August 2003, consumers may not see any change with the new prices. But, the new prices should help minimize any rate increase that could occur when caps are lifted in 2003 (presumably, this is because the higher rates now may lead to the deferral of fewer expenses).[13]

NEW YORK

Customer choice in New York has been moderate with most competitive offers and switching being in industrial and commercial sectors. In the entire state, 26.2 percent of the non-residential and 5.5 percent of the residential load is served by competitive suppliers. In the non-residential sector, 6.9 percent of the customers and in the residential sector five percent of the customers have switched suppliers. Among all areas, the highest switching in the non-residential sector has occurred in the Rochester Gas and Electric (RG&E) service territory. In this area, 27.4 percent of non-residential customers (42.4 percent of load) and 11.9 percent of residential customers (14.1 percent of load) have switched to competitive suppliers. There have been two competitive offers for some time for residential customers in this service territory, one each from Energy Co-Operative of New York (ECN) and Energetix. The offer of Energetix is 2.10 cents per kWh as against 2.22 cents per kWh of RG&E for generation and the offer of ECN has five percent savings from the price of RG&E. Thirty two percent of load migration has occurred in this area. In the residential sector, the highest percentage of switching has occurred in Orange and Rockland Utilities (O&R)

[13] Compiled with News release, New Jersey Board of Public Utilities, February 15, 2002; Reuters, February 15, 2002; Ashbury Press, February 16, 2002; PSEG Fact Sheet, November, 2001 and Restructuring Weekly.

service territory. In this area, 21 percent of customers (24.3 percent of the load) have migrated to alternative suppliers, including 19.2 percent of non-residential customers (32.3 percent of load). O&R service territory has the highest (20.8 percent) percentage of customers served by alternative suppliers. In other service areas, switching in the residential sector is relatively less active, though ECN has offers providing savings of five to six percent in the service territories of New York State Electric and Gas (NYSEG), Niagara Mohawk Power Corporation (NMPC) and RG&E.

Figure 6 shows load migration in each of the service territories in New York as of May 2002.

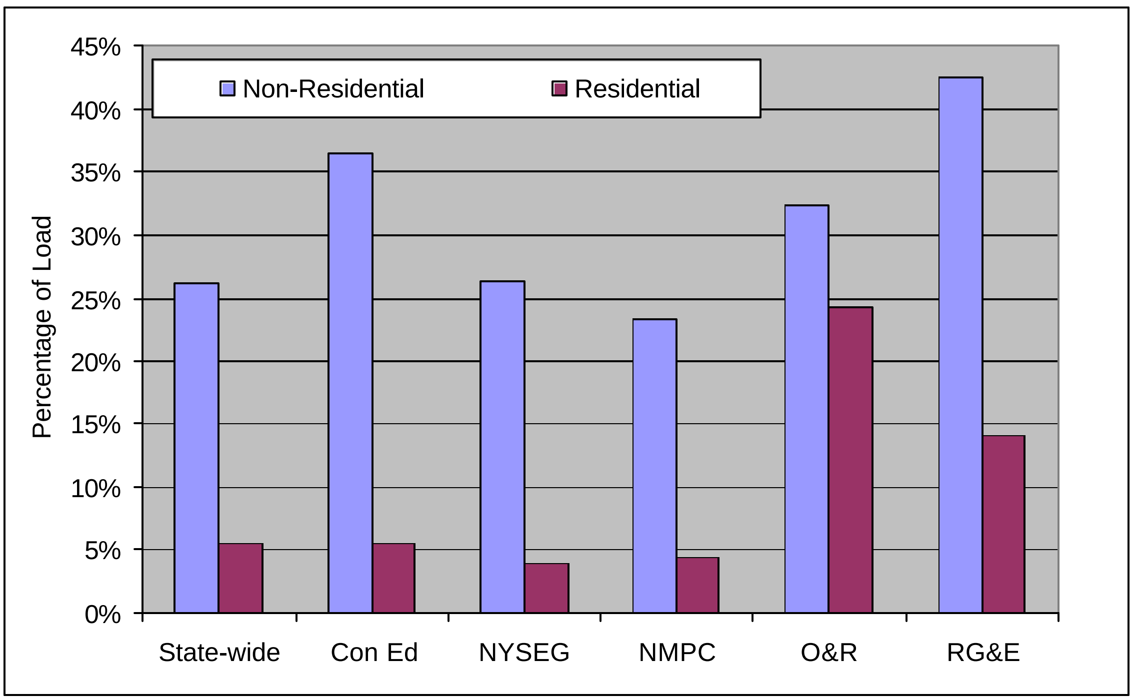

Figure 6. Load migration in New York as of May 2002

Source: Compiled with data from New York State Public Service Commission Website

Figure 7 shows customer migration in each of the service territories in New York.

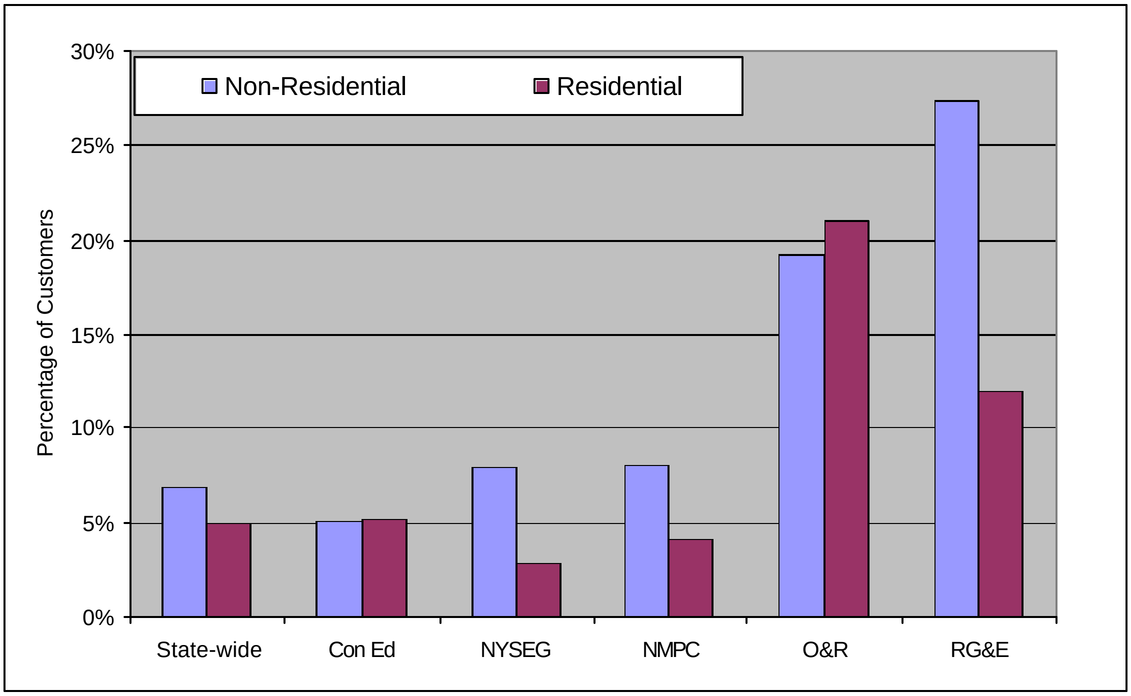

Figure 7. Customer migration in New York as of May, 2002.

Source: Compiled with data from New York State Public Service Commission Website

Due to the increase in wholesale power prices, customers have seen prices go up. For example, NMPC which sold most of its generating assets has to purchase power from the wholesale market now. As a result, residential customers have seen the price of generation go up from 3.29 to 4.76 cents per kWh. In May, the New York Public Service Commission (PSC) approved NMPC's green power program. This supports the state's policies to promote renewable energy and to require state agencies to purchase 20 percent of their electricity from renewable energy sources by 2010.

In January 2002, the New York PSC approved new financial requirements for energy service companies (ESCOs). ESCOs doing business in New York will now have to meet a minimum bond rating from an independent rating agency before offering prepayment plans or requiring security deposits. ESCOs that do not earn the minimum rating will have to put security deposits in escrow or issue an irrevocable letter of credit.[14]

[14] Energy Central Professional, January 23, 2002.

In **Georgia,** retail access is not being considered at this time. In 1998, workshops were held and a report was issued which resulted in the opening of a number of dockets to deal with the issues related to restructuring. At this time work on these dockets has been put “on hold.” No formal decision by the Commission or legislature has been taken either way, however.

In **North Carolina,** a legislative study commission adopted a recommendation with a time line for moving to retail competition, but no legislation has been introduced in the legislature. The study commission itself is no longer taking actions consistent with the time line it adopted.

The 2000 session of the **South Carolina** legislature studied restructuring but took no action. There has been no action subsequently**.**

In March 2000, the **West Virginia** legislature adopted a retail competition plan that scheduled choice for all customers to begin in January 2001 with implementation of this plan made contingent on enactment of tax reform legislation in 2001, which did not occur. In 2002, however the legislature has said that it intends to hire an independent consultant to consider the Commission’s plan on restructuring in light of activities in other states.

Review of Key States: Maine, Ohio, Pennsylvania and Texas

MAINE

Maine's Restructuring Act required complete divestiture of transmission and distribution utilities' generation assets. Some observers believe that this was a key element for the program's success so far, as it eliminated any incentive for utilities to favor one supplier over another. Under Maine’s restructuring law, distribution utilities are entitled to recovery of stranded costs through a stranded cost charge, which is included in the transmission and distribution rates of the distribution utility. Stranded costs which are eligible for recovery include regulatory assets from generation, the difference between net plant investments associated with the distribution utility's generation assets and the market value of generation assets and the difference between future contract payments and the market value of the distribution utility's purchased power contracts. Distribution utilities must make mitigation efforts, and they will be allowed recovery of stranded costs comparable to their recovery prior to the start of retail competition. The MPUC calculated stranded costs for all distribution utilities and may adjust and correct stranded cost estimates and charges at any time. In 2003 and every three years thereafter, the MPUC is required to review stranded costs and correct estimates and adjust costs.[15]

Industrial and large commercial customers in Maine have a diverse selection of electricity suppliers from which to choose.[16] With many options available, about 3,102 non-residential consumers have switched to alternative electricity suppliers in Maine. The residential market is relatively less active in Bangor Hydro-electric Company (BHE) and Central Maine Power Company (CMP) service territories. There have been no offers in the service areas of BHE and CMP since July 2001. Maine Public Service Company (MPS) territory, which has a relatively large percentage of residential and small commercial customers served by an alternative supplier, has also seen a sizeable increase in the rate of switches in May and June, 2002. This could be because of a competitive offer at 5.14 cents per kWh in May 2002 by Energy Atlantic, whereas the standard offer service price is 5.69 cents per kWh. Another possible reason could be the relatively low number of customers served by MPS, that is 35,467 residential, 193 medium and sixteen large customers.

Electricity prices have also fallen since restructuring was implemented and the standard offer (the default energy service) prices (which represent generation portion only) were recently lowered by forty to fifty percent (sic) for medium and large commercial and industrial customers of both CMP and BHE. About 37 percent of the states' load is served by competitive suppliers as of July 2002.

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[15] Me. Rev. Stat. Ann. Public Utilities 35-A, 3208(2000).

[16] Business Wire, March 27, 2002: Maine Public Utilities Commission Website, March 28, 2002.

Table 5 shows the percentage of different categories of load served by competitive suppliers.

Table 5. Summary of load switching in Maine

Month	BHE			CMP			MPS			
	Res/S. Comm.	Medium	Large	Res/S. Comm.	Medium	Large	Res/S. Comm.	Medium	Large	**STATE TOTAL**
Jun-00	<1%	2%	46%	<1%	6%	65%				
Oct-00	<1	3	28	<1	9	64	9	76	52	**27**
Jan-01	<1	3	29	<1	15	65	9	65	74	**29**
Apr-01	<1	7	31	<1	21	75	9	63	53	**33**
Jul-01	<1	9	41	<1	29	81	9	52	82	**37**
Oct-01	<1	20	69	<1	36	88	4	37	88	**43**
Jan-02	<1	28	74	<1	45	90	10	56	88	**46**
Apr-02	<1	35	86	<1	47	89	14	65	99.6	**47**
Jul-02	<1	35	43	<1	33	80	31	69	99	**37**

Source: Compiled with data from Maine Public Utilities Commission Website

According to the 2001 Annual Report of the Maine Public Utilities Commission (MPUC), the high level of migration is due to a sharp increase and subsequent decline in generation market prices. In fall 2000, natural gas prices rose to historically high levels. This price spike was reflected in the prices electric suppliers bid for standard offer service. When natural gas prices and generation market prices subsequently declined, the earlier effect remained embedded in standard offer prices, offering competitive suppliers an attractive opportunity to sell to Maine consumers. Another reason cited is aggregation. The number of licensed aggregators increased from sixteen in 2000 to eighteen in 2001. Four active aggregators recruited large and medium customers during 2000 and expanded their recruitment to additional medium customers during 2001. Less formal groupings accomplished similar results. In addition to aggregation, competitive providers directly solicited some individual large customers as well as companies with multiple branches.

The report also finds that the development of a residential market has occurred only in Northern Maine, where as many as ten percent of residential customers had migrated to competitive suppliers during 2001. There are a variety of reasons for the slow development of this market. Some providers assert that the standard offer price is below market price -- where the standard offer price has been set through an open market bid process. Furthermore, MPS's standard offer price of 4.29 cents in 2000 and 5.577 cents in 2001 resulted in at least some migration, but BHE's higher price of 7.3 cents in 2001 resulted in virtually no migration, suggesting that factors other than price influence market development. Limited transmission access has been mentioned as a factor.

OHIO

Ohio's restructuring legislation allowed electric power generation to be competitive beginning January 1, 2001. The Public Utilities Commission of Ohio (PUCO) will initiate a proceeding by March 31, 2003, to determine the feasibility of competition in metering, billing, collection and ancillary services. During Ohio's market development period, incumbent distribution utilities continue to provide standard offer service to customers who do not choose an alternative supplier and for those customers whose chosen supplier defaults in providing service. During the market development period customers will receive standard offer service at prices approved by the PUCO. Residential customers received a five percent rate reduction on the distribution utility's unbundled generation service component effective January 1, 2001. The PUCO can alter or remove this rate reduction if it determines that this rate reduction has discouraged entry by competitive suppliers. After the market development period, standard offer service will be provided at market rates,[17] which may be obtained by competitive bidding for either the customers or the load. A distribution utility, that offers both

[17] The rule governing the post-market development period has yet to be determined. The market development period for all distribution companies other than Dayton Power and Light Company ends on December 31, 2005. For Dayton Power and Light Co. it will end on Dec 31, 2003. Further details are in Appendix B.

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. Ohio's restructuring law allowed the utilities to recover PUCO-approved stranded costs attributable to net costs related to generation service that are unrecoverable in the competitive market, regulatory assets and employee assistance costs. The utilities may recover these costs from their customers through the standard offer rate, and through a per kWh charge from customers who switch to a competitive supplier.

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 to represent 100 communities with more than 600,000 potential members. Toledo and seven local governments in the area of Toledo formed an aggregation group of more than 131,600 members.

According to the Division of Market Monitoring & Assessment of the PUCO, as of March 31, 2002 a total of 647,600 people or 13.85 percent of eligible consumers switched to new electric suppliers. Cleveland Electric Illuminating Company had 52.5 percent of its residential customers and Toledo Edison had 45.8 percent of its residential customers switch to alternative suppliers. In the area of Ohio Edison 16.4 percent of residential customers have switched, but in the areas of Dayton Power and Light Company and Ohio Power Company no residential customer has chosen an alternative supplier. Cincinnati Gas and Electric and Southern Power each had less than one percent of residential customer switching.

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

Company and Ohio Edison. As of March 2002, aggregation programs account for 80.6 percent of residential, 59 percent of the commercial and 21 percent of the industrial customer switching in Ohio. Table 6 illustrates the contribution of aggregation programs to customer switching.

Table 6. Aggregation activity in Ohio

As of March 2002	Customer Switching thru Aggregation	Total Customer Switching	Percent Switching thru Aggregation
Residential	501074	621716	80.60%
Commercial	14684	24911	58.95%
Industrial	223	1049	21.26%

Source: Compiled with data from PUCO website

Pursuant to an agreement with the NOPEC, Green Mountain Energy will construct a 25-kilowatt solar array at Lake Farmpark in Kirtland, Ohio. Under another agreement with municipal aggregation services provider American Municipal Power-Ohio (AMPO), Green Mountain Energy Company will provide green electricity to residents in the Ohio communities of Alliance, Sandusky, London, and the village of Lagrange. The customers will have the option to receive electricity from Green Mountain or remain with their current supplier.

Figure 8 shows the percentage of residential customers that have switched to alternative suppliers as of March, 2002.

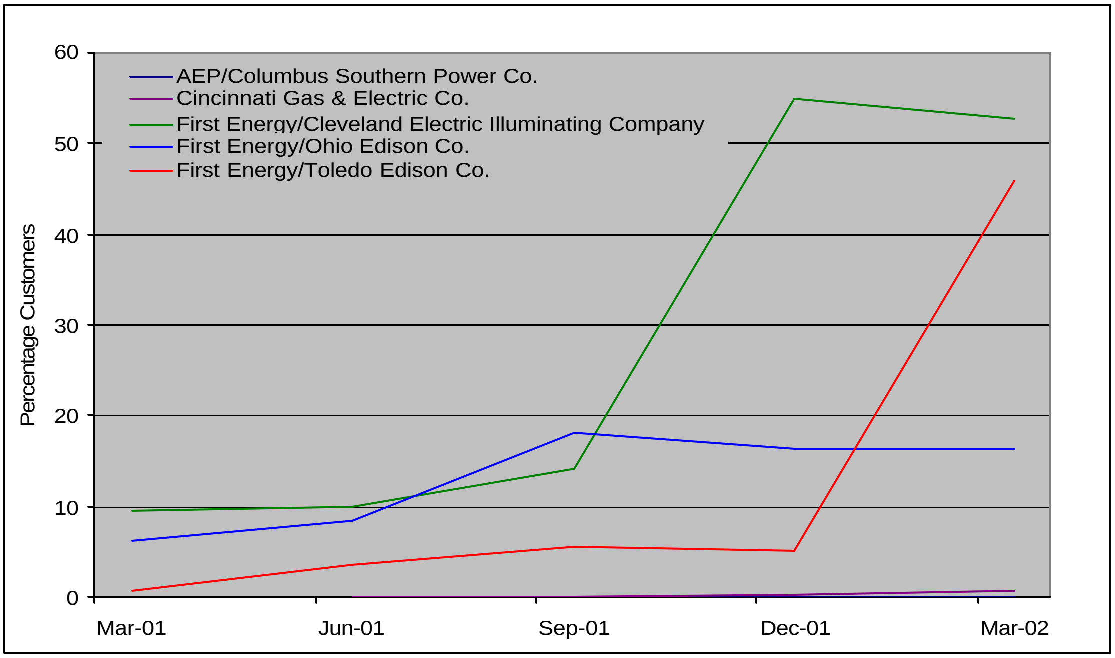

Figure 8. Ohio: Residential customers served by alternative suppliers
Source: Drawn with data from PUCO Website

Figure 9 shows the percentage of residential load that has switched to alternative suppliers as of March, 2002.

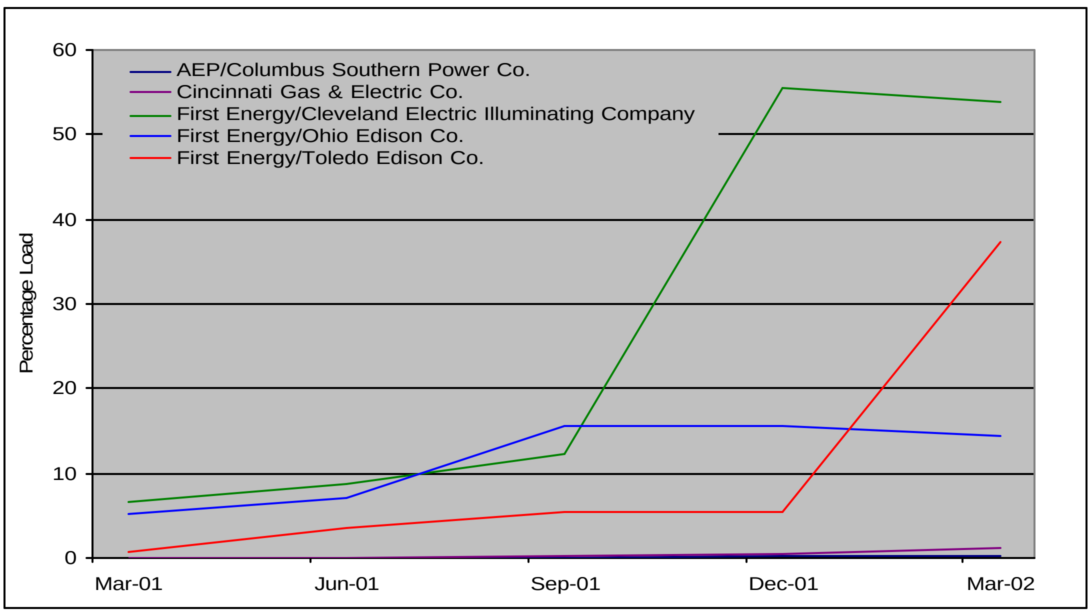

Figure 9. Ohio: Residential load served by alternative suppliers
Source: Drawn with data from PUCO Website

Under an agreement with the PUCO and various parties, First Energy 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 First Energy's customers. Of the total MSG capacity, 500 MW is reserved for residential customers. Total power allocations for the three northern Ohio First Energy 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 the three First Energy 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.[18]

Figure 10 shows a summary of residential offers for the entire state. The total number of offers has gone down from eight in January 2001 to three in May 2002, though the number of distribution company areas with offers has gone up from one in January 2001 to three in May 2002. Currently, there is one offer in each of the First Energy Companies, Ohio Edison Co., Cleveland Electric Illuminating Co., and Toledo Edison, with savings of 3.5 percent from the utility's bill. All these offers are from First Energy Solutions, an affiliate of the utility. There are currently no offers in the service areas of the remaining five utilities. After the bankruptcy declaration of NewPower, First Energy Solutions is the only supplier making offers in the state.

[18] From 2001 Performance Review of Electric Power Markets By Ken Rose, Selina Lim, Venkata Bujimalla Review conducted for Virginia State Commission Corporation

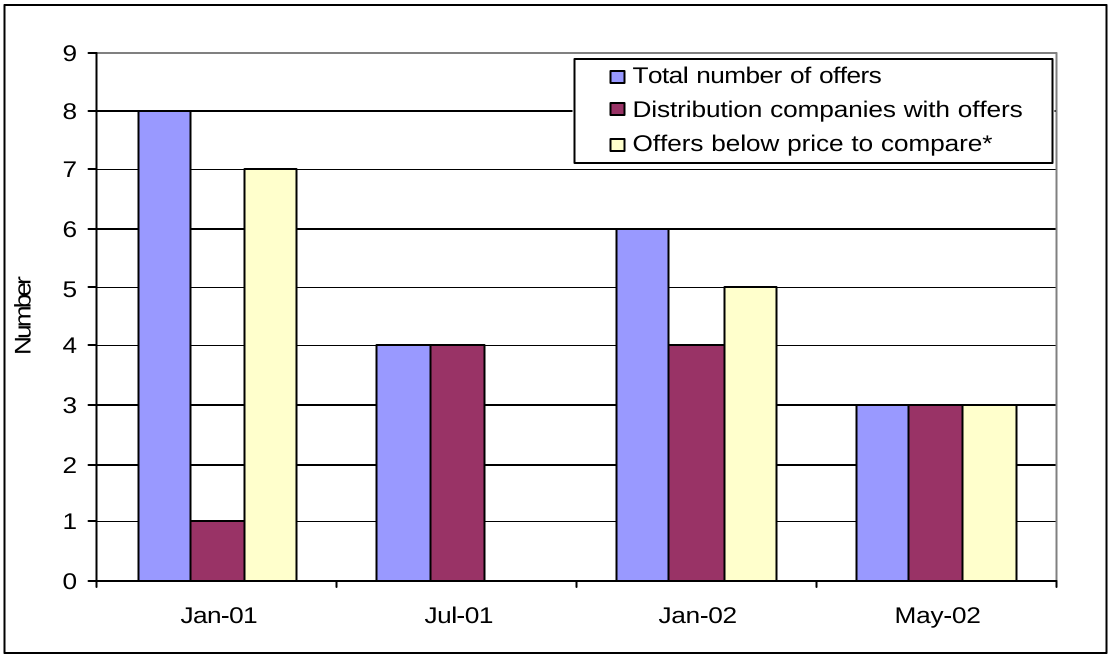

Figure 10. Ohio: Summary of competitive offers
Source: Drawn with data from www.wattagemonitor.com
*These offers are available one each in the service territories of only three distribution companies

According to the "report card" issued in January 2002 by the Ohio Consumers' Counsel (OCC), typical consumers who used 850 kWh of electricity per month had average annual savings from $10 to $110 in 2001. OCC also reported that only two alternate suppliers are actively marketing to Ohio residential customers.[19] The OCC warned that time is running out on the three-year rate freeze for Dayton power and Light customers which is due to expire on December 31, 2003. The OCC stated that if certain crucial issues are not addressed, the price consumers pay is likely to rise, because residential customers have not had any opportunities to switch suppliers. [20]

Table 7 shows summary of offers in the service areas of each of the distribution companies.

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[19] They were NewPower Company and First Energy Solutions. At this time only one supplier i.e. First Energy Solutions which is affiliated with three distribution utilities in Ohio, is making offers in the service areas of the same three distribution companies.

[20] Ohio Consumers' Counsel Website.

Table 7. Summary of Ohio's residential retail electric offers

AEP/Columbus Southern Power Co.	Jan 2001	Mar 2001	May 2001	Jul 2001	Sep 2001	Nov 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	0	0	1	0	0	0	0	0	0
Number of offers from various sources	0	0	2	1	1	1	1	0	0
Total number of offers	0	0	3	1	1	1	1	0	0
Number of monthly contracts	0	0	2	0	0	0	0	0	0
No.of long-term or year-long contracts	0	0	1	1	1	1	1	0	0
No.of offers below price-to-compare	0	0	1	0	1	1	0	0	0
Number of suppliers	0	0	3	1	1	1	1	0	0
Generation price	NA	NA	5.48	5.48	5.12	5.12	5.12	NA	NA
% Savings on lowest generation price	-	-	NA	-	5.08%	5.08%	-	-	-
Cincinnati Gas & Electric	Jan 2001	Mar 2001	May 2001	Jul 2001	Sep 2001	Nov 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	0	1	1	0	0	0	0	0	0
Number of offers from various sources	0	2	2	1	1	1	1	1	1
Total number of offers	0	3	3	1	1	1	1	1	1
Number of monthly contracts	0	2	2	0	0	0	0	0	0
No.of long-term or year-long contracts	0	1	1	1	1	1	1	1	1
No.of offers below price-to-compare	0	1	1	0	1	1	1	1	1
Number of suppliers	0	3	3	1	1	1	1	1	1
Generation price	NA	4.47	4.47	4.47	5.27	5.27	5.27	5.27	5.27
% Savings on lowest generation price	-	8.7%	NA	-	14.0%	14.0%	7.0%	7.0%	7.0%
First Energy/ Ohio Edison Co.	Jan 2001	Mar 2001	May 2001	Jul 2001	Sep 2001	Nov 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	0	1	1	0	0	0	0	0	0
Number of offers from various sources	8	2	2	1	1	1	2	1	1
Total number of offers	8	3	3	1	1	1	2	1	1
Number of monthly contracts	5	2	2	0	0	0	0	0	0
No.of long-term or year-long contracts	0	1	1	1	1	1	2	1	1
No.of offers below price-to-compare	7	1	1	0	1	1	2	1	1
Number of suppliers	6	3	3	1	1	1	1	1	1
Generation price	4.24	4.21	4.21	4.21	4.42	4.42	4.42	4.42	4.42
% Savings on lowest generation price	25.7%	13.3%	NA	-	2.0%	0.7%	12.9%	3.5%	3.5%
First Energy/ Toledo Edison Co.	Jan 2001	Mar 2001	May 2001	Jul 2001	Sep 2001	Nov 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	0	1	1	0	0	0	0	0	0
Number of offers from various sources	0	2	2	1	1	1	2	1	1
Total number of offers	0	3	3	1	1	1	2	1	1
Number of monthly contracts	0	2	2	0	0	0	0	0	0
No.of long-term or year-long contracts	0	1	1	1	1	1	2	1	1
No.of offers below price-to-compare	0	1	1	0	1	1	2	1	1
Number of suppliers	0	3	3	1	1	1	1	1	1
Generation price	NA	NA	4.23	4.23	4.70	4.70	4.70	4.70	4.70
% Savings on lowest generation price	-	13.2%	NA	-	6.2%	4.9%	16.6%	3.5%	3.5%

First Energy/ Illuminating Co.	Jan 2001	Mar 2001	May 2001	Jul 2001	Sep 2001	Nov 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	0	0	0	0	0	0	0	0	0
Number of offers from various sources	0	0	0	0	0	0	0	0	0
Total number of offers	0	0	0	0	0	0	0	0	0
Number of monthly contracts	0	0	0	0	0	0	0	0	0
No.of long-term or year-long contracts	0	0	0	0	0	0	0	0	0
No.of offers below price-to-compare	0	0	0	0	0	0	0	0	0
Number of suppliers	0	0	0	0	0	0	0	0	0
Generation price	NA	NA	NA	NA	NA	NA	NA	NA	NA
% Savings on lowest generation price	-	-	-	-	-	-	-	-	-
AEP/Ohio Power Co.	Jan 2001	Mar 2001	May 2001	Jul 2001	Sep 2001	Nov 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	0	1	1	0	0	0	0	0	0
Number of offers from various sources	0	1	1	0	0	0	0	0	0
Total number of offers	0	2	2	0	0	0	0	0	0
Number of monthly contracts	0	2	2	0	0	0	0	0	0
No.of long-term or year-long contracts	0	0	0	0	0	0	0	0	0
No.of offers below price-to-compare	0	1	1	0	0	0	0	0	0
Number of suppliers	0	2	2	0	0	0	0	0	0
Generation price	NA	3.80	3.80	NA	NA	NA	NA	NA	NA
% Savings on lowest generation price	-	8.95	NA	-	-	-	-	-	-
Dayton Power & Light	Jan 2001	Mar 2001	May 2001	Jul 2001	Sep 2001	Nov 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	0	1	1	0	0	0	0	0	0
Number of offers from various sources	0	1	1	0	0	0	0	0	0
Total number of offers	0	2	2	0	0	0	0	0	0
Number of monthly contracts	0	2	2	0	0	0	0	0	0
No.of long-term or year-long contracts	0	0	0	0	0	0	0	0	0
No.of offers below price-to-compare	0	1	1	0	0	0	0	0	0
Number of suppliers	0	2	2	0	0	0	0	0	0
Generation price	NA	NA	4.11	NA	NA	NA	NA	NA	NA
% Savings on lowest generation price	-	-	NA	-	-	-	-	-	-
Monongahela Power Company	Jan 2001	Mar 2001	May 2001	Jul 2001	Sep 2001	Nov 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	0	0	0	0	0	0	0	0	0
Number of offers from various sources	0	0	0	0	0	0	0	0	0
Total number of offers	0	0	0	0	0	0	0	0	0
Number of monthly contracts	0	0	0	0	0	0	0	0	0
No.of long-term or year-long contracts	0	0	0	0	0	0	0	0	0
No.of offers below price-to-compare	0	0	0	0	0	0	0	0	0
Number of suppliers	0	0	0	0	0	0	0	0	0
Generation price	NA	NA	NA	NA	NA	NA	NA	NA	NA
% Savings on lowest generation price	-	-	-	-	-	-	-	-	-

Source: www.wattagemonitor.com

PENNSYLVANIA

There has been a marked decline in retail activity in Pennsylvania since the early part of 2001. The number of customers and amounts of load served by alternate suppliers saw a continuous decline until October 2001, but showed marginal improvement in late 2001. With the transfer of 180,000 customers of NewPower (an affiliate of Enron that ceased to be a competitive supplier) back to PECO Energy in April 2002, the number of customers and load supplied by alternative suppliers has declined in April-July 2002 quarter. Figure 11 shows load served by alternative suppliers since July 2000.

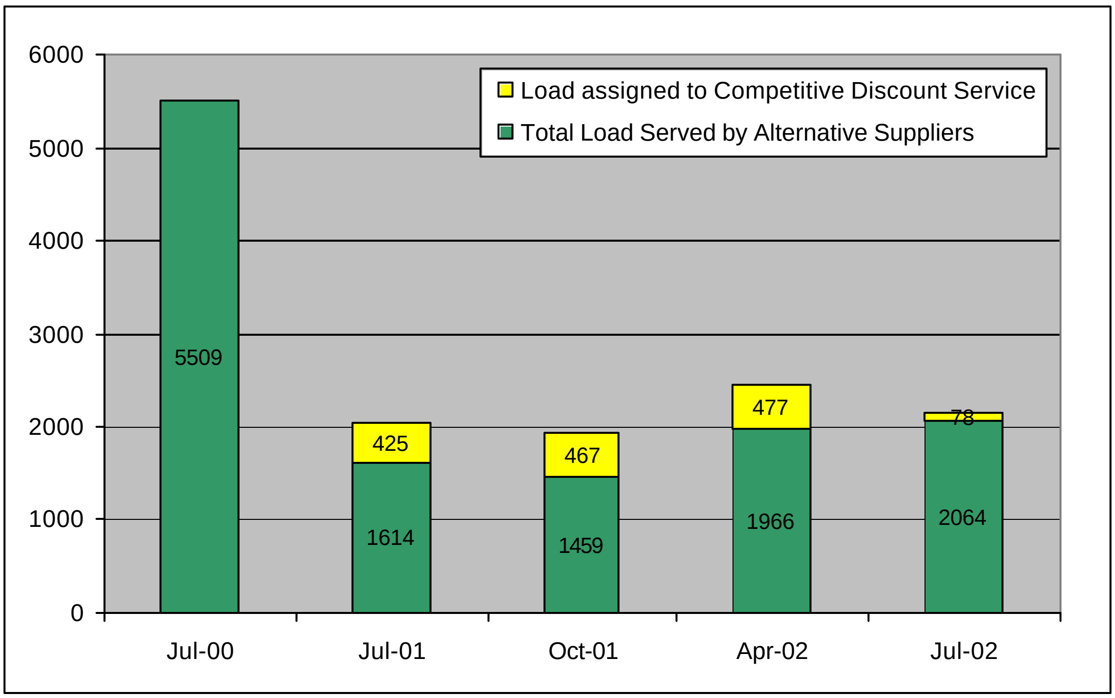

Figure 11. Pennsylvania customer load in MW served by alternative suppliers

Source: Drawn with data from Pennsylvania Office of Consumer Advocate Website

The total number of offers and offers below the price-to-compare to residential customers has also declined from July 2000. Figure 12 shows total number of offers and offers below the price-to-compare.

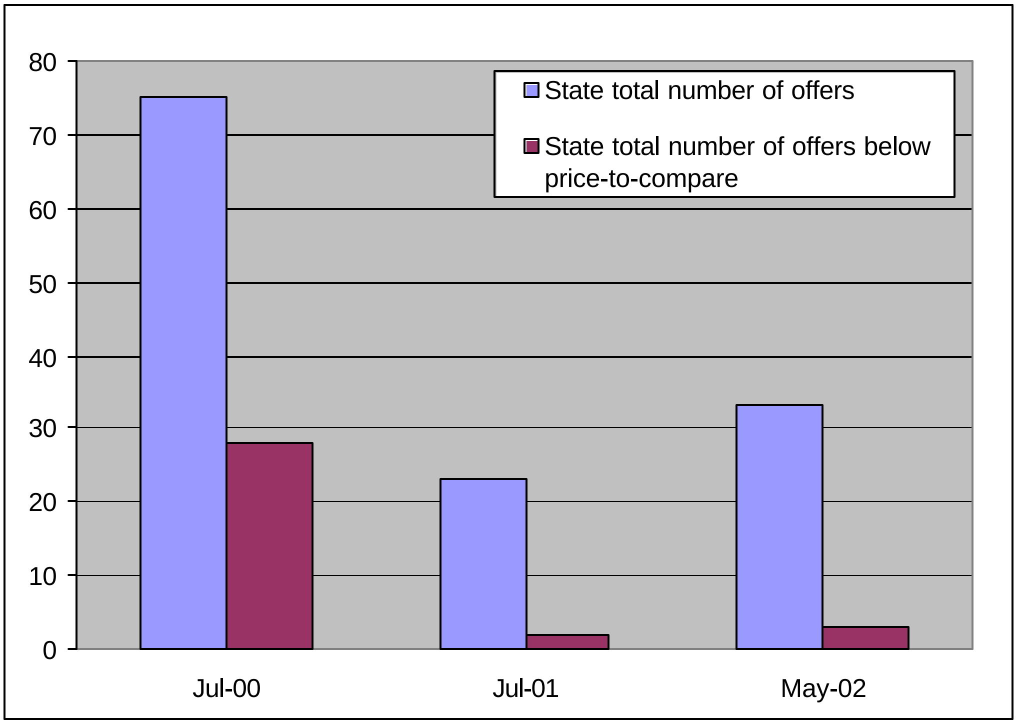

Figure 12. Pennsylvania: Summary of offers

Source: Drawn with data from www.wattagemonitor.com

As of July 1, 2002 some 305,422 customers accounting for a load of 2,142 MW are served by alternate suppliers comparing to 535,445 customers accounting for 8,320 MW of load served as of April 1, 2000. Of this decrease, a substantial reduction in numbers occurred in spring 2001.The decline in load has been more dramatic. This is explained by the expiration of a large number of long-term contracts that were held by large industrial and commercial customers. Many suppliers who entered the Pennsylvania power market in 1999 have subsequently left, when wholesale prices skyrocketed because of high natural gas prices and tight electric capacity. This resulted in substantial industrial and commercial load switching back to their traditional electric utility. Between April 1, 2001, and July 1, 2001, the number of commercial and industrial customers using an alternative supplier fell by 78 percent and 81 percent respectively.

On January 1, 2001, PJM Interconnection raised installed capacity requirements to 119 percent of the expected demand of the companies. This is the requirement on all “load serving entities” in PJM to either own capacity or purchase a capacity credit. After the new requirement was established, the price of installed capacity sold by PPL Corporation increased sharply from $5 or less, to $177 per megawatt per day and, during constrained periods, to $354 per megawatt per day. Several power suppliers were forced to pull out of the market as a result. During its investigation, the Pennsylvania Public Utility Commission found evidence that PPL EnergyPlus unfairly manipulated wholesale electricity markets in early 2001, damaging the wholesale and retail electricity markets. A detailed discussion of the impact is in the wholesale section of this report.

According to Douglas l. Biden, president of the Electric Power Generation Association “Pennsylvania's electric rates, which were almost 15 percent above the national average in 1997, before Pennsylvania's deregulation law passed are one percent lower now.” While some point out that deregulation has saved consumers in Pennsylvania $4 billion, others argued that most of the savings have come from state-mandated rate caps and other one-time reductions and hence the credit should go to the mandatory regulatory accomplishment rather than a market-based outcome.

Pennsylvania's Electricity Generation Customer Choice and Competition Act allowed utilities to pass power plant construction costs, or stranded costs, to customers. In March 2002, Pennsylvania's Duquesne Light Company became the first utility to eliminate the Competitive Transition Charge (CTC) from the electric bills of its residential customers. Duquesne Light sold its power plants to Orion Midwest in 2000 and has used the sale to pay off its stranded costs. Duquesne customers can expect a 16 percent decrease on their bills from the elimination of the CTC. Last year, Duquesne Light's 500,000 customers paid $274 million in stranded costs. Other Pennsylvania utilities are expected to eliminate their CTCs in seven years. [21]

Table 8 is a summary of offers to residential customers in the service territories of each of the distribution companies in Pennsylvania. As can be seen, there has been a decline in the total number of offers in the service territories of each of the utilities.

[21] Pittsburg Post-Gazette, March 27, 2002; Duquesne Light Website, March 28, 2002.

Table 8. Summary of Pennsylvania's residential retail electric offers

Allegheny Power	Jul 2000	Jan 2001	Jul 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	4	3	2	3	3	3
Number of offers from various sources	2	1	0	0	0	0
Number of offers	6	4	2	3	3	3
Number of monthly contracts	4	4	2	3	3	3
Number of long-term or year-long contracts	2	0	0	0	0	0
Number of offers below price-to-compare	2	1	0	0	0	0
Number of suppliers	3	2	2	2	2	2
Bundled "Price to Compare" *	6.76	6.76	7.34	3.30	3.30	3.30
Percent savings on lowest offer	4.81%	5.03%	-	-	-	-
Duquesne Light	Jul 2000	Jan 2001	Jul 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	4	3	2	4	4	4
Number of offers from various sources	3	3	1	1	1	1
Number of offers	7	6	3	5	5	5
Number of monthly contracts	5	5	2	4	4	4
Number of long-term or year-long contracts	2	1	1	1	1	1
Number of offers below price-to-compare	3	3	0	0	0	0
Number of suppliers	4	4	3	4	4	4
Bundled "Price to Compare" *	12.52	12.52	12.52	4.72	4.72	4.72
Percent savings on lowest offer	7.67%	5.75%	-	-	-	-
Metropolitan Edison Company	Jul 2000	Jan 2001	Jul 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	5	3	2	3	3	3
Number of offers from various sources	6	3	0	1	1	0
Number of offers	11	6	2	4	4	3
Number of monthly contracts	8	6	2	4	4	3
Number of long-term or year-long contracts	3	0	0	0	0	0
Number of offers below price-to-compare	4	1	0	0	0	0
Number of suppliers	8	4	2	3	3	2
Bundled "Price to Compare" *	9.15	9.15	9.19	4.78	4.78	4.78
Percent savings on lowest offer	9.95%	5.03%	-	-	-	-

Pennsylvania Electric Company	Jul 2000	Jan 2001	Jul 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	4	3	2	3	3	3
Number of offers from various sources	7	3	0	1	1	0
Number of offers	11	6	2	4	4	3
Number of monthly contracts	8	6	2	4	4	3
Number of long-term or year-long contracts	3	0	0	0	0	0
Number of offers below price-to-compare	6	3	0	0	0	0
Number of suppliers	9	4	2	3	3	3
Bundled "Price to Compare" *	8.89	8.89	8.91	4.77	4.77	4.77
Percent savings on lowest offer	10.24%	4.95%	-	-	-	-
Pennsylvania Power Company	Jul 2000	Jan 2001	Jul 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	4	3	2	4	4	4
Number of offers from various sources	5	3	1	1	1	0
Number of offers	9	6	3	5	5	4
Number of monthly contracts	7	5	2	4	4	3
Number of long-term or year-long contracts	2	1	1	1	1	1
Number of offers below price-to-compare	3	3	0	0	0	0
Number of suppliers	6	4	3	4	4	3
Bundled "Price to Compare" *	10.41	10.41	10.41	5.50	5.50	5.50
Percent savings on lowest offer	7.49%	5.00%	-	-	-	-
Pennsylvania Power and Light	Jul 2000	Jan 2001	Jul 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	4	3	2	2	2	3
Number of offers from various sources	4	4	0	1	1	0
Number of offers	8	7	2	3	3	3
Number of monthly contracts	6	6	2	3	3	3
Number of long-term or year-long contracts	2	1	0	0	0	0
Number of offers below price-to-compare	2	2	0	0	0	0
Number of suppliers	6	5	2	2	2	2
Bundled "Price to Compare" *	8.61	8.61	8.66	4.86	4.86	4.86
Percent savings on lowest offer	10.57%	5.00%	-	-	-	-

PECO	Jul 2000	Jan 2001	Jul 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	5	6	5	6	6	7
Number of offers from various sources	11	9	2	3	3	2
Number of offers	16	15	7	9	9	9
Number of monthly contracts	9	7	4	5	5	5
Number of long-term or year-long contracts	7	8	3	4	4	4
Number of offers below price-to-compare	6	9	2	3	3	3
Number of suppliers	13	12	7	7	7	7
Bundled "Price to Compare" *	13.27	12.86	14.1	5.82	5.82	5.82
Percent savings on lowest offer	8.97%	10.81%	2.55%	7.21%	7.21%	7.21%
UGI Utilities	Jul 2000	Jan 2001	Jul 2001	Jan 2002	Mar 2002	May 2002
Number of renewable offers	4	3	2	2	2	3
Number of offers from various sources	3	2	0	1	1	0
Number of offers	7	5	2	3	3	3
Number of monthly contracts	5	5	2	3	3	3
Number of long-term or year-long contracts	2	0	0	0	0	0
Number of offers below price-to-compare	2	1	0	0	0	0
Number of suppliers	4	3	2	2	2	2
Bundled "Price to Compare" *	9.45	9.45	9.49	4.83	4.83	4.83
Percent savings on lowest offer	7.41%	4.97%	-	-	-	-

Source: Complied with data from www.wattagemonitor.com
* The figures until July 2001 are total bundled price and the figures from Jan 2002 are only for the generation component.

TEXAS

The Texas restructuring bill passed on June 18, 1999, provided for retail competition for generation beginning January, 2002. Metering services for commercial and industrial customers will be open to competition beginning January 1, 2004. For residential customers, metering services are regulated until September 1, 2004 or until forty percent of customers have switched to an alternative supplier, whichever is later. Competition is allowed in all areas other than those served by municipal utilities and electric cooperatives, unless the governing body of the city or cooperative opts for retail competition. Texas restructuring laws also require that an independent transmission organization be established before retail competition begins in a power region.

Under Texas restructuring law, utilities were required to separate their business activities into three units: a wholesale electric power generation company, a transmission and distribution company (T&D company), and a retail electric provider (REP). This separation can take place either through the sale of assets to a third party, by the creation of separate holding company, or by the creation of non-affiliated companies. Wholesale power generation companies that are affiliated with a distribution utility are required to auction off fifteen percent of their installed generation capacity. Also, subject to certain exceptions, no such wholesale generation company can own more than twenty percent of the installed capacity that can be sold in the region.

Texas regulators decided to delay electric restructuring in the Southwest Power Pool (SPP) area of north Texas comprising the service territory of Southwestern Electric Power Company (SWEPCO) and the small non-ERCOT service area of West Texas Utilities (WTU). Similarly, retail electric competition for customers in southeast Texas who are served by Entergy within the Southeastern Reliability Council (SERC) was delayed until 2003. The Commission believes that these areas are ill-prepared for competition and customers would not benefit from a competitive market. In the absence of a Regional Transmission Organization there is little interest by retail providers in entering these markets. Deregulation has been delayed until at least January 1, 2005, for the El Paso area, which is served by El Paso Electric Company, and until January 1, 2007, for the Texas Panhandle, which is serviced by Xcel Energy. These companies continue to operate as regulated utilities subject to the jurisdiction of the Public Utility Commission of Texas (PUCT).

The Electricity Reliability Council of Texas (ERCOT) operates its own interconnect (grid), which includes most of Texas. It is an intrastate grid, in that no part of ERCOT crosses a state boundary. The ERCOT grid is synchronous, meaning that all generators in Texas are producing power in phase with each other. However, ERCOT is not synchronous with either the Eastern or the Western Interconnection and there are no AC interties between them. There are, however, two AC/DC/AC (basically, a DC line with an AC converter at each end) interties between ERCOT and the Eastern Interconnection. This allows some minimal unilateral directional transfers of power into or out of ERCOT. These unilateral directional power flows are made without making ERCOT a synchronous part of the interstate grid. Thus, even though some power flows between the two grids, they are not in synch and the electrons flowing over the ERCOT grid are not in interstate commerce. Thus, wholesale sales within ERCOT come from Texas generators. The wholesale sales within ERCOT are not considered to be in interstate commerce. Because of this, the Public Utility Commission of Texas regulates all retail sales in Texas and the PUC of Texas regulates all of the wholesale sales and transmission service within ERCOT. 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 FERC is not involved.[22]

Under Texas restructuring legislation, distribution utility base rates were frozen at September 1, 1999 rates until January 1, 2002. Utilities were required to continue existing services to customers until that time. Effective January 1, 2002, standard offer customers were transferred to the retail affiliate of the distribution utility. Residential and small commercial customers receive standard offer service at the fixed "price to beat" rate, which is at least six percent less than the rate prior to January 1, 2002. Other customers are subject to market-based rates. The utilities, Central Power and Light, Reliant Energy, TXU SESCO, TXU Electric, Texas-New Mexico Power Company, and West Texas Utilities, have established bundled price to beat rates between 5.99 and 8.88 cents per kWh. As it turned out, these rates are up to 18.08 percent below the regulated utility rates that were in effect in December 2001 and are a much higher discount than the six percent minimum mandated by the law in some areas. The utilities must offer the established price-to-beat until January 1, 2007, and can offer different rates beginning January 1, 2005, or earlier if at least forty percent of their residential and small commercial customers switch to competitors. The rates may also be changed up to twice per year if changes in natural gas prices

[22] Robert Burns of NRRI supplied this ERCOT/Texas information.

and power costs occur, subject to PUCT approval. The new rates, mandated by the Texas deregulation law, offer a price reduction to customers who do not switch to a new provider when competition begins. Further, no REP affiliate of a T&D utility can offer competitive rates to residential and small commercial customers in the service territory of a T&D utility as long as the price-to-beat rates are in effect.

Independent retail suppliers are also known as “retail electric providers” or REPs. The PUCT was authorized to designate for each service territory, at least one REP as the Provider of Last Resort (POLR) to provide service to customers whose suppliers go out of business or whose service is terminated by the supplier. POLRs will provide standard offer service at a PUCT approved fixed and non-discountable rate. These rates are established through a competitive bidding process. The retail affiliate of the distribution utility cannot be the POLR in the service territory of the distribution utility except at the price-to-beat rate.

Texas distribution utilities are allowed to recover all of their net non-mitigated stranded costs through a transition charge. The Commission is authorized to determine the amount of stranded costs eligible for recovery, which include uneconomic generation related assets and purchased power contracts. The distribution utilities were allowed to securitize one hundred percent of their regulatory assets before January 1, 2001. Up to 75 percent of estimated stranded costs are allowed to be recovered over a period not exceeding fifteen years. The total securitized stranded costs are about $2.8 billion.

The Texas electric choice pilot program, to serve five percent of the state's residential ratepayer base, originally was scheduled for June 1, 2001, but was rescheduled three times and finally began on July 31, 2001. Problems in testing of computer systems and programming issues caused the delays. The pilot program faced a number of problems in switching customers to new suppliers because of communication difficulties between the independent organization and participating companies' computers. The pilot program ended when the entire market was opened to retail access on January 1, 2002.

The Texas wholesale market experienced significant transmission congestion in August 2001. Six companies allegedly scheduled more power than was needed in congested zones, and then collected fees to remove the power from the transmission system to clear the way for other energy providers. The PUCT investigated to determine whether this practice was the result of intentional market manipulation. The PUCT's initial analysis indicated that six companies generated at least $1 million each by exploiting a market design flaw and over-scheduling their load projections. The commission claimed that a rule (which was changed in February 2002) allowed all companies serving load in the wholesale market to be charged for transmission congestion costs, rather than requiring the companies that caused the congestion to pay for it, and may have led to overcharges of up to $45 million.

A number of issues regarding deregulation in Texas have surfaced. Most important among them is the slow process by which consumers moving to a new location are able to get their service. Table 9 shows the total number of customers in the service areas of each of the utilities as of 2000 (which are the latest figures available from EIA[23]) and the number of customers whose switching has been completed, scheduled to be switched or in review as of July 22, 2002 (in column 3), and the percentage of load sold by competitive REPs (in column 5). As the table shows the highest percentage of load in MWhs served by competitive suppliers is in WTU, which has relatively fewer number of total customers. For the entire state, 19.2% of the load is served by competitive suppliers. This includes that supplied by the affiliates of other distribution companies. As noted, under Texas' restructuring law, wholesale power generation companies were required to auction off fifteen percent of their installed generation capacity, so it is likely that most of that capacity is being used to serve customers in the original utility's service territory.

[23] From Table 14. "Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Revenue per kWh for the Residential Sector by State and Utility, 2000" on the Energy Information Administration Website at www.eia.doe.gov.

Table 9. Customer switching activity in Texas

T&D Utility	Total number of customers as of 2000	Number of customers in the process of moving to competitive suppliers	Percentage Customers in the process of moving to competitive suppliers [24]	Percentage MWh sold by all REPs non-affiliated to T&D Utility
Oncor (TXU)	2,603,029	199,970	7.68%	11.9%
Reliant	1,694,729	160,473	9.47%	24.7%
CPL	672,742	21,576	3.21%	28.9%
TNMP	204,078	5,975	2.93%	21%
WTU	190,338	7,217	3.79%	32%
TXU-SESCO	42,976	2	0	NA
Total	**5,407,892**	**395,213**	**7.31%**	**19.2%**

Source: Compiled with data from PUCT Website and www.eia.doe.gov

In the absence of availability of information on switching to competitive suppliers by customer class who have chosen competitive suppliers, and from the percentage of load and the customers shown above, it cannot be ruled out that a larger number of large non-residential customers may have chosen competitive suppliers.

Table 10 shows a summary of offers to residential customers and the savings on the lowest offer. The savings for an average residential consumer range from approximately $5 per month in the Texas-New Mexico Power territory to over $8 per month in the Reliant and West Texas Utilities territories. In large metro areas, like Houston and Dallas, it appears that savings for commercial customers may exceed thirty percent a month.[25]

[24] Because of growth in the Texas area, this percentage may be overstating the amount of switching to some extent.

[25] Wattage Monitor Press Release, January 28, 2002; The Dallas Morning News, January 29, 2002.

Table 10. Summary of Texas' residential retail electric offers

TXU Electric and Gas	Jan-02	Mar-02	May-02
Number of renewable offers	2	2	2
Number of offers from various sources	12	13	11
Total number of offers	14	15	13
Number of monthly contracts	7	7	6
Number of long-term or year-long contracts	7	8	7
Number of offers below price-to-compare	11	10	9
Number of suppliers	9	10	9
Price to beat	8.25	8.25	8.25
Percent savings on lowest offer	15.15%	11.51%	11.51%
Reliant Energy	Jan-02	Mar-02	May-02
Number of renewable offers	1	1	1
Number of offers from various sources	13	13	11
Total number of offers	14	14	12
Number of monthly contracts	7	7	6
Number of long-term or year-long contracts	7	7	6
Number of offers below price-to-compare	12	11	9
Number of suppliers	10	10	9
Price to beat	8.62	8.62	8.62
Percent savings on lowest offer	17.63%	9.51%	7.19%
Central Power and Light	Jan-02	Mar-02	May-02
Number of renewable offers	0	0	1
Number of offers from various sources	6	7	7
Total number of offers	6	7	8
Number of monthly contracts	2	2	3
Number of long-term or year-long contracts	4	5	5
Number of offers below price-to-compare	5	4	4
Number of suppliers	3	4	5
Price to beat	8.80	8.80	8.80
Percent savings on lowest offer	9.77%	6.81%	6.81%
Texas New Mexico Power Company	Jan-02	Mar-02	May-02
Number of renewable offers	2	2	2
Number of offers from various sources	3	4	4
Total number of offers	5	6	6
Number of monthly contracts	5	5	5
Number of long-term or year-long contracts	0	1	1
Number of offers below price-to-compare	2 1	3	2
Number of suppliers	4	5	5
Price to beat	8.66	8.66	8.66
Percent savings on lowest offer	9.33%	4.15%	3.00%

West Texas Utilities	Jan-02	Mar-02	May-02
Number of renewable offers	0	0	0
Number of offers from various sources	6	6	6
Total number of offers	6	6	6
Number of monthly contracts	2	2	2
Number of long-term or year-long contracts	4	4	4
Number of offers below price-to-compare	5	5	5
Number of suppliers	3	3	3
Price to beat	8.88	8.88	8.88
Percent savings on lowest offer	14.97%	9.34%	9.91%
TXU Sesco	Jan-02	Mar-02	May-02
Number of renewable offers	-	-	-
Number of offers from various sources	-	-	-
Total number of offers	-	-	-
Number of monthly contracts	-	-	-
Number of long-term or year-long contracts	-	-	-
Number of offers below price-to-compare	-	-	-
Number of suppliers	-	-	-
Price to beat	-	-	-
Percent savings on lowest offer	-	-	-

Source: Compiled with data from www.wattagemonitor.com

Analysis of offers in Table 10 shows that there are a relatively high number of offers from the affiliates of other T&D utilities in the service areas of each of the utilities. As Table 11 shows, about 57 percent of the total offers in the state and about 68 percent of the offers below the price-to-compare are from the affiliates of other utilities. First Choice Power which is an affiliate of Texas New Mexico Power Co has four offers each in the service territories of all other utilities other than TXU SESCO. TXU Energy Services which is an affiliate of TXU Electric Co has one offer each in the service areas of all other utilities other than TXU SESCO. Reliant Energy Retail, an affiliate of Reliant Energy has two offers each in TXU and TNMP. Entergy Solutions, an affiliate of Entergy Gulf States, Inc has one offer in the service area of Reliant Energy. It is not reported how much of the customer or load switching was to an affiliate of other Texas utilities.

Table 11. Summary of inter-affiliate offers in Texas' residential retail market

Transmission and Distribution Utility Service Area	Total number of offers in May 2002	Number of offers from the affiliates of other T&D utilities in My 2002	Total number of offers below the price to compare in May 2002	Number of offers below price to compare from other T&D utilities in May 2002
TXU Electric	13	6	9	5
Reliant Energy	12	6	9	5
Central Power and Light	8	5	4	3
TNMP	6	4	2	2
WTU	6	5	5	5
TXU SESCO	0	0	0	0
Total	45	26	29	20

Source: Complied with data from www. wattagemonitor.com

Reportedly, deregulation has caused confusion on the part of customers and suppliers about the way that orders for new electricity service are placed and processed. Before January 1, 2002, only the regulated utility needed to be contacted; now there are three different entities involved in processing information relating to service requests, the new retail electricity provider, the utility (which provides delivery service) and ERCOT (the independent transmission organization). The usual wait for a service change has also gone up from 1 or 2 days to two to five days. [26]

Despite the delays, customer complaints, and confusion, Texas consumers have the opportunity to benefit from lower electricity prices.

According to the 2001 ERCOT annual report, Texas needs more electricity transmission lines. The report has identified six congested interfaces where more lines are needed, including transmitting power from south to north Texas and bringing electricity into the Dallas area. Utilities in ERCOT have completed several major transmission projects recently to address these constraints, and a number of other projects are in the construction, licensing, or planning stage.

[26] Houston Chronicle, January 17, 2002.

Summary of Electric Restructuring Activity in the Northeast Region

CONNECTICUT

Since Connecticut restructured its electric industry after the enactment of SHB 5005 two years ago, customer choice is emerging slowly. Four alternative suppliers, Connecticut Energy Cooperative, Select Energy, Dominion, and Green Mountain Energy, were offering services to about 25,000 consumers. In Connecticut the standard offer price is set to guarantee savings for consumers who remain with their utility and to protect them from price spikes. Northeast Utilities (NU) has requested that the Department of Public Utility Control (DPUC) increase the standard offer rate so that suppliers can enter the market and competition can begin, with the expectation that prices will be lower in the long term. The standard offer rate is set to expire at the end of 2003. At present, the standard offer rate in Northeast Utilities area is 5.64 cents per kWh and in United Illuminating area is it is five cents per kWh. Until July 2002, Connecticut Energy Cooperative offered its EcoWatt product at 6.50 cents per kWh and guaranteed that a portion of the electricity was produced from environmentally friendly plants. Its ValueWatt product was at 5.25 cents per kWh, which was lower than the standard offer price in Northeast Utilities' area. As the cooperative went bankrupt, it is no longer offering the service. Dominion is offering service through Levco, which is an aggregator.

MASSACHUSETTS

Retail activity in Massachusetts residential segment continues to be quiet. Since July 2001 there was has been no activity in the state's residential market, no offers in any of the Commonwealth's service territories. As of now only 0.6 percent of the residential- non-low-income customers are served by competitive suppliers. However, a steady increase in supplier selection activity is seen in the large commercial and industrial customers from June 2001. Figure 13 shows percentages of various categories of customers choosing a competitive supplier.

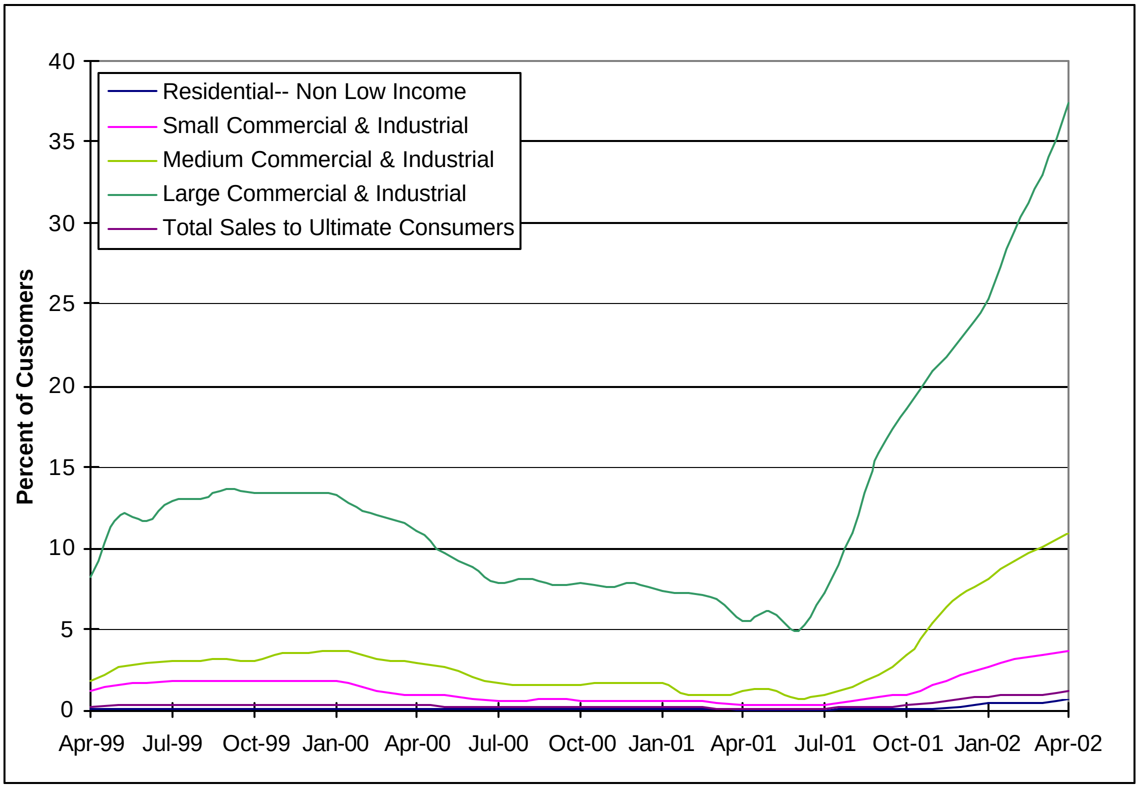

Figure 13. Massachusetts customers choosing a competitive supplier

Source: Drawn with data from Massachusetts Division of Energy Resources Website.

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. Customers who had not selected a competitive supplier as of March 1, 1998, were placed on standard offer service. (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 and (3) competitive generation service provided by competitive suppliers.

In November 2001, Dominion Retail Inc. began making offers to residential customers in Massachusetts retail electricity market. Dominion offered an alternative choice of power supply to Massachusetts Electric's 270,000 residential customers who are receiving default service. Average default residential customers can receive power from Dominion at a price of $66.31 per month (based on average usage) if they commit to a three-year deal, which is slightly less than the $67.75 for Massachusetts Electric default customers (i.e. a commitment for three years results in total savings of about $52). However, it is still more than the proposed $57.56 per month that an average Massachusetts Electric standard offer customer will pay beginning January 1, 2002, pending state approval. Currently there are already several companies competing for commercial and industrial customers in the state's electric marketplace.[27]

In March 2002, electric market prices were below standard-offer rates and default service rates. Default rates more than doubled from a year ago, and now the market is more attractive for competitive suppliers. Although the standard-offer for Massachusetts Electric customers will likely drop from 5.6 cents per kWh hour to 4.2 cents per kWh in July 2002, competitive suppliers' rates will likely still be lower. About one percent of all Massachusetts Electric customers use a competitive supplier, but about 24 percent of those customers are companies with average monthly use in excess of 200 kilowatts.[28]

NEW HAMPSHIRE

New Hampshire began to allow retail access on May 1, 2001. In New Hampshire customers can join together to form a buying group to buy energy in bulk. These groups may be formed by consumers, or a third party aggregator may help organize consumers into a buying group. Though there are four registered suppliers and eight aggregators, as of July 2002, there were no offers to residential customers.

On April 25, 2002 New Hampshire General Court, the state's legislative body, passed a bill (H 718) to permit electric utilities to establish renewable energy options as part of restructuring transition services. The legislation establishes guidelines for utilities that choose to offer electricity generated from

[27] Boston Herald, November 22, 2001; Utility Spotlight, November 26, 2001.

[28] Telegram & Gazette, March 5, 2002.

renewable resources to their customers, including rate structures and regions in which the renewable energy is generated. The bill also contains a provision that allows utilities to offer energy efficiency programs partially funded through the state's system benefits charge.

RHODE ISLAND

Though competition was phased in beginning July 1, 1997, in Rhode Island, few alternative suppliers have entered the Rhode Island retail market, and a large majority of 460,000 customers still buy power from the state's largest utility, Narragansett Electric. Only about 2,700 customers purchased electricity directly from outside companies as of March 2002. Figure 14 shows the customer migration in Rhode Island. About 0.58 percent customers were purchasing 12.9 percent of the load from competitive suppliers in June 2002. There are no offers to residential customers at this time. The low price-to-compare is the likely reason for the absence of competitive offers.

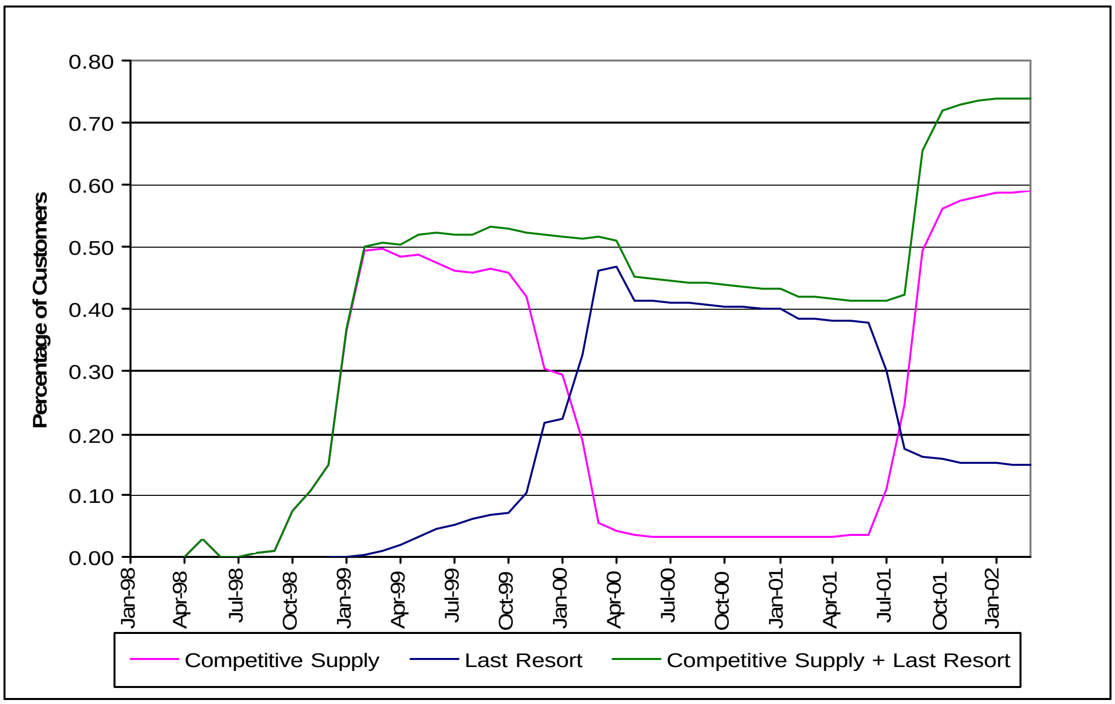

Figure 14. Rhode Island customer migration

Source: Drawn with data from Rhode Island Public Utilities Commission & Division of Public Utilities and Carriers Website

The Rhode Island Public Utility Commission (PUC) approved a lower standard offer rate of 4.662 cents per kWh in January 2002, for Narragansett Electric Company despite opposition from energy marketers and suppliers, who alleged the lower rate would stifle competition. The PUC said the lower standard offer rates were set in order to give customers rate stability. The new rates are to end in three years, when the standard offer begins to expire in other areas of the region. Standard Offer service will continue to be available in Rhode Island through 2009. Restructuring measures passed in 1996 required Narragansett to sell its generation assets and focus on delivering electricity to customers. Since competition has been fairly stagnant, Narragansett has been purchasing power from outside suppliers for most of its 460,000 customers.

In 2002, the Utilities Restructuring Act of 1996 was amended to allow municipalities to aggregate customer demand on behalf of residents. According to the bill, the local utility would continue to distribute electricity to customers. A majority of voters in a municipality would have to approve the switch of generation suppliers before its implementation, and residents could choose to opt out of the plan and stay with their local utility. Residents who do not opt out must stay with the municipality's chosen supplier for two years or pay a "switching fee" if they choose to leave.

Summary of Electric Restructuring Activity in the Midwest Region

ILLINOIS

Illinois residential customers became eligible for electric choice on May 1, 2002. At this time, no energy companies have registered with the Illinois Commerce Commission (ICC) to serve residential market and also none of the utilities have expressed interest in serving residential customers outside their home service areas. Illinois electric utilities do not need to receive certification from the ICC to serve customers outside their home service areas. Collectively, the Alternative Retail Electric Suppliers (ARES) and the electric utilities serving outside their service areas are called “Retail Electric Suppliers” (RESs). Although there are few offers, there are approximately seventeen suppliers of which about ten are active to serve non-residential customers, who have had the opportunity to choose their electric supplier since December 31, 2000. However, mandated reductions in residential bundled rates and the rate freeze for commercial and industrial customers have provided significant consumer benefits. In 2001, about twelve million MWh representing about fourteen percent of the load eligible for delivery services were supplied by RESs. It appears that RES marketing activities were solely confined to the service areas of the state's three largest utilities, AmerenCIPS, Commonwealth Edison ("ComEd") and Illinois Power.[29]

In May 2002, the Illinois legislature enacted Public Act 92-537, which extended the current freeze on electricity rates until 2007. The lawmakers believe that safeguards built into the restructuring legislation passed in 1997 would assure that "excess earnings" if any, for utilities would be distributed back to consumers. The Illinois House also enacted a law that would order the ICC to conduct a study on the value of aggregating customers to negotiate electricity rates with local utilities. The study would include an analysis of the potential costs and benefits of aggregation and barriers to municipal and other forms of aggregation. The report of the study is due on January 15, 2003.

MICHIGAN

Michigan started retail access in January 2002 and the program is still in nascent stage. According to the Status of Electric Competition report of the Michigan Public Service Commission (MPSC) for 2001, competition in Michigan's retail electric choice program expanded during 2001. More than 3,200 customers were participating in the state's three Retail Open Access (ROA) programs at the end of 2001, a 30 percent increase over 2000 numbers. Five new electric generating plants began operating in 2001, bringing the total of new in-state electric generating capacity to 3,000 MW since 1999. Further, the Commission

[29] Assessment of Retail and Wholesale Market Competition in Illinois Electric Industry in 2001 by Illinois Commerce Commission.

has completed reviewing a plan to increase transmission capacity by 2,000 MWs by June 2002.

The MPSC, in November 2001, adopted standards to protect retail electric consumers from slamming and cramming. The Customer Choice and Reliability Act of 2000 requires the Commission to issue orders to protect Michigan's electric customers from slamming and cramming and authorizes the Commission to conduct contested proceedings to investigate any violations.

The MPSC has also adopted nine rules addressing net stranded costs, incumbent utility depreciation, unbundling, disclosure standards, distribution standards, retail open access tariffs and restructuring implementation to advance Michigan's competitive electricity environment. The rules will facilitate equitable treatment of new energy marketers, competitors, incumbents, and customers. The Commission adopted a methodology for net stranded costs as the difference between the revenue requirements associated with fixed generation assets, generation-related regulatory assets, and capacity payments associated with purchase-power agreements and the revenues available to cover those costs.[30] In 2002, Detroit Edison and Consumers Energy did not qualify for stranded cost recovery. The commission will review the issue annually.

Michigan Public Service Commission (MPSC) has allowed $468 million in securitization bonds by Consumers Energy. The securitization is part of the utility's implementation of Michigan's electric competition law. Consumers Energy is required to reduce rates by five percent. The cut is to be financed through the issuance of low-cost bonds. Consumers Energy has sought approval from the MPSC for its three-year "Green Power Pilot Program." If the program is approved, customers would have the opportunity to purchase green power. Participating consumers would pay a "Green Surcharge" that would be passed on to green generators.

According to the Michigan Retailers Association, Michigan's Electric Choice program has brought significant savings to retail businesses in the state. Retail businesses have saved between ten and thirty percent on reduced electric

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[30] Electric Power Daily, December 26, 2001.

bills. The program's current supplier, Quest Energy of Ann Arbor, provides electricity for fifty retail businesses with at least hundred locations. [31]

Summary of Electric Restructuring Activity in the Western Region

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. The Electric Competition Act, (HB 2663), which was signed in 1998, allowed phased 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 there have been no offers since then and now there are no customers served by alternative suppliers. It appears that the stranded cost charges and high wholesale prices of the last year during the California crisis have made it uneconomical for marketers to compete with incumbent utilities.

The ACC is re-examining the state's deregulation plan at the request of Commissioner William Mundell. Commissioner Mundell has asked that the rules for competition be re-evaluated in light of California's experience, in order to consider the possibility of a different path for the transition to competition. The re-examination comes amidst a request from the Arizona Public Service Company (APS) to the ACC to overturn rules that require the utility to acquire all of its power needs from the competitive market by 2004. APS argues that despite the construction of twenty new power plants, the competitive market will not be able to supply enough power by that time. Instead, APS has asked that the utility be allowed to acquire power from its parent company, Pinnacle West Capital. Competitors such as Duke Energy, Pacific Gas & Electric, and Reliant Energy argue that the change would undermine competition in Arizona[32].

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[31] Grand Rapids Business Journal, March 22, 2002.

[32] The Arizona Republic, December 6, 2001, Electric Power Daily, December 7, 2001.

MONTANA

In December 1999, as part of a transition to competition, Montana Power Company (MPC) completed its sale of generating assets to PPL Montana. MPC waived the statutory deadline for the Commission to issue a final order on the MPC transition plan. The Montana Public Service Commission (PSC) has not yet issued a final order on Montana Power Company's sale plan. In a June 26, 2001 order, the Montana PSC declared that PPL Montana, the owner of Montana Power's generating assets, must sel electricity to MPC at prices reflecting costs as if the assets had not been sold, holding that MPC's sale of its generation assets did not disintegrate MPC from an electric monopoly public utility with generation, transmission and distribution functions. PPL Montana sued the Montana PSC claiming that PSC is attempting to regulate Montana Power Company's electric rates after a legislature-mandated rate freeze. PPL Montana also sought to prevent the Montana PSC from "seeking to exercise any authority, control or regulation of wholesale sales from PPL Montana's generating assets." [33]

A lawsuit by Single Moms, Inc., (a group of three women) claiming that Montana's 1997 electric utility deregulation law was unconstitutional because deregulation laws have caused or would cause huge power rate increases has been rejected by Chief U.S. District Judge Don Molloy in March 2002. Judge Molloy ruled that no fundamental right was infringed by the 1997 Legislature's passage of utility deregulation and that the deregulation law was "reasonable under the circumstances existing in 1997." Judge Malloy said it is clear that the Deregulation Act of 1997 was rationally related to legitimate state purposes to regulate commerce and reduce utility rates. [34]

No offers are currently being made to residential customers in Montana.

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[33] Compiled with information from the Order No. 5968t (Docket No. D97.7.90) and The Electricity Daily, July 17, 2001.

[34] The Montana Standard, September 13, 2001.

In **Oregon** direct access is an available option for eligible non residential customers. However, none of the eligible customers has yet elected direct access through an alternative supplier. Oregon Revised Statue 757.601 (2) directs Public Utility Commission to report to the legislature by January 1, 2003 whether residential customers would benefit from direct access to electricity services.

Nevada passed restructuring legislation AB 366 in July 1997. But, due to the California crisis, the restructuring statue was revoked in April 2001. The 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 with the approval of the Commission. The customer must, however, provide evidence of the impact of their leaving the system will have on other customers. The petition could be denied or an exit fee could be charged, if a significant cost is involved. The first cases are currently being processed.

Section II: Status of Electric Wholesale Markets

As noted in Section I, what occurs in the wholesale markets directly affects the performance of retail markets. If retail prices are capped, then when wholesale prices for energy and capacity increase, the headroom available for alternative suppliers to be competitive is squeezed or can disappeared completely. While raising the cap can increase retail market activity, this may simply pass the higher cost of wholesale power due to market power through to retail customers. This underscores the importance of not only considering the wholesale cost of power to suppliers relative to the retail price customers pay, but also the competitiveness of the wholesale market itself and how close prices are to a competitive market outcome.

As with last year's report, price trends and performance in the wholesale markets of California, New England, PJM, and New York are reviewed. These markets continue to have more publicly available and complete price data and analyses than other regions of the country. This section summarizes, after a summary of recent events in the industry, price and other data analyses to provide an indication on how these markets are performing.

Recent power industry turmoil

Since last year's report, the electric supply industry has been beset by a series of disturbing revelations and scandals, beginning with Enron Corporation's collapse[35] in late 2001. Enron's collapse quickly became an accounting scandal as investigations revealed improper accounting treatment of partnerships and subsidiaries. The company's stock collapse devastated many investors' portfolios, including many former Enron employees,

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[35]The Washington Post has a comprehensive five part series on Enron's rise and collapse, "The Fall of Enron: The Private Decisions Behind the Company's Public Collapse," available online at: http://www.washingtonpost.com/wp-dyn/business/specials/energy/enron/.

and began a series of revelations of accounting improprieties in other industries that continues to this day.

The effect of Enron's collapse on the electric supply industry was two-fold. First, Enron claimed to be the largest energy trader in the country, so its disappearance should of had an immediate affect on power markets. It appears, however, that other energy market participants were able to quickly absorb the loss of Enron's presence and markets showed no immediate impacts. A reason for this may be due to Enron's own exaggeration of its trading volume and activity in wholesale power markets and the type of trades Enron was involved in. A recent FERC staff investigation noted that they had "retrieved information indicating that Enron may have been involved in considerable electricity and natural gas round trips or wash sales."[36] In these types of trades, a company sells power to another company or to its subsidiary with a simultaneous purchase of the same product at the same price to artificially inflate revenue and trading volume. The FERC staff investigation report gives an example of the potential negative impact on the market of such trades, stating that "wash trading provides the illusion of a deep market (that is, more volume than absent wash trades), which may lead buyers to assume they are getting a competitive price and trading in a liquid market when in fact they are not."[37]

Questions also began to be raised about the trading practices of other power traders and marketers as well and in May of 2002, the Federal Energy Regulatory

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[36]The Federal Energy Regulatory Commission, report prepared by the FERC staff, "Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies," Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-000, August 2002, pp. 58-59.

[37]FERC Staff Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, August 2002, p. 58.

Commission (FERC) ordered[38] 150 power traders[39] to disclose details of any "round trip," "wash," or "sell/buyback" trades these companies may have engaged in the western markets during the years 2000-2001. The FERC Order asked the respondents to admit or deny that their company had engaged in any wash, round trip or sell/buyback trading activities.

This FERC investigation revealed that a number of companies were engaging in these transactions. For example, it was reported that CMS Energy Corporation inflated its revenue by $5.2 billion over the last two years, which accounted for 23.3 percent of its revenue in that period.[40] Duke Energy acknowledged that it made 89 round trip trades that boosted revenues by $217 million between January 1, 1999, and June 30, 2002 (Duke's overall revenue was $75.6 billion during this period).[41] Other companies have admitted to round-trip trades as well, including Dynegy, Inc and Reliant Resources, Inc.[42] The Securities and Exchange Commission, the Commodity Futures Trading Commission, Department of Justice, and FERC are currently investigating several dozen other power traders and other industry activities as well.

A second major impact from the Enron collapse stems from the revelation of manipulation of trading rules in California during the crisis of 2000 and 2001. Details of

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[38]Federal Energy Regulatory Commission, "Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-000," May 21, 2002.

[39]See Attachment A to May 21, 2002 "Fact-Finding Investigation," Sellers of Wholesale Electricity and/or Ancillary Services In the U.S. Portion of the WSCC During 2000-2001.

[40]Kenneth Bredemeier, *The Washington Post*, "Caution: Energy Trading, Today the Power Industry Fears the Risk," July 26, 2002. This article also noted that CMS's chief executive and the head of its trading arm resigned after the disclosures.

[41]Paul Nowell, *The Associated Press*, "Duke Energy Fires 2 Over Trades," August 2, 2002. A Duke spokesperson noted in the article that none of these trades involved the California market.

[42]Chris Baltimore, *Reuters*, "FERC concerned by US power firm downgrades," July 17, 2002.

how Enron was able to do this was revealed in three memos[43] released in May of 2002 by FERC as part of its investigation of the western market power crisis. While there is evidence that these transactions were only a small portion of the overall price runup in California[44] and the west, they have garnered a large share of the media attention and have raised questions about the efficacy of restructured markets. The FERC staff investigation report notes that "[w]hile the exact economic impact of the Enron trading strategies is difficult to determine precisely, Staff concludes that these now infamous trading strategies have adversely affected the confidence of markets far beyond their dollar impact on spot prices."[45]

The recent disclosures of wholesale market improprieties and a moderating of wholesale prices (largely from softer demand due to a slower economy) have resulted in declining credit ratings and falling share prices for many energy companies. This "credit crunch" has impacted the ability of suppliers to raise capital and forced companies to cut back on their energy trading operations and plant investments. By one estimate merchant energy companies have lost over two-thirds of their equity value over an 18 month period.[46]

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[43]These memos are currently available at http://www.ferc.gov/electric/bulkpower/pa02-2/pa02-2.htm along with other information gather as part of FERC's investigation of western markets. These are the memos that outlined Enron's strategies with colorful names such as "Death Star," "Get Shorty," "Ricochet," and "Fat Boy."

[44]Frank Wolak, a professor in the Department of Economics at Stanford University and Chairman of the Market Surveillance Committee of the California ISO, estimated that "the strategies outlined in these [Enron] memos, at most, account for $500 million when aggregated over all California market participants." This is less than five percent of the more than $10 billion the California ISO has calculated that California customers paid from "unjust and unreasonable" wholesale electricity prices from June 2000 to June 2001. Frank Wolak, testimony before the Senate Committee on Commerce, Science and Transportation, U.S. Senate, May 15, 2002.

[45]FERC Staff Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, August 2002, p. 5.

[46]Lawrence Makovich (of Cambridge Energy Research Associates) quoted by Chris Baltimore, *Reuters*, "Energy Sector Weakness Could Threaten Power Supplies,"

Between January and late July 2002, Dynegy and Williams stock prices had each fallen 95 percent, El Paso was down 77 percent, Reliant Resources was down 73 percent, and Duke Energy had fallen 52 percent.[47] Some energy companies have had their corporate ratings reduced below investment grade (that is, to “junk” status). Fitch Ratings, which tracks “downgrades-to-upgrades” ratios of companies, stated that for all US corporations, the ratio was 4:1 for the first half of 2002, while for the global power group’s companies, it was 18 downgrades to 1 upgrade (it was 6:1 for the first half of 2001).[48]

In response to the credit crunch, power trading companies have reduced their trading staff, including Aquila, Inc., which cut 400 employees in its trading operation and was trying to sell its power trading division (the company later decided to completely exit the wholesale energy marketing and trading business), Dynegy cut 50 employees from its 300-person trading operation, El Paso cut half of its 600-person trading group, and CMS reduced its trading staff from 224 to 158.[49] Energy companies have also been selling assets as well to shore up their balance sheets. For example, Dynegy sold its Northern Natural Gas pipeline to Warren Buffett’s MidAmerican Energy Holdings for $928 million (Dynegy had paid Enron Corp. $1.5 billion in November of 2001)[50] and is looking to sell UK assets as well.[51]

July 24, 2002.

[47]Laura Goldberg and Michael Davis, *Houston Chronicle*, “Energy Traders Take Beating,” July 24, 2002.

[48]Steven Poruban, “U.S. Energy Merchants Face Period of ‘Extreme Stress,’” Oil & Gas Journal, August 9, 2002.

[49]Kenneth Bredemeier, *The Washington Post*, “Caution: Energy Trading, Today the Power Industry Fears the Risk,” July 26, 2002.

[50]Reuters, “Dynegy soars 36 pct, bonds rise after pipeline sale,” August 19, 2002.

[51]Tim Webb, Sunday Business (London), “U.S. Energy Sector Collapse Sparks Asset Free-for-All in Britain,” August 18, 2002. Other companies reported to be selling assets in the U.K. were Aquila, Mirant, and AES.

Perhaps more important in the long run for consumers is that this has also led to a cut back in investment in future generating capacity. By one estimate, since the beginning of 2002, about one-third of the proposed new capacity in the country has been shelved or postponed, nearly 92,000 megawatts.[52,53] This means less future supply and fewer new suppliers to compete with existing suppliers; either preserving existing market power of current suppliers or increasing the potential for the exercise of market power by existing suppliers in the future. Given the long lead-time to permit, site, and build new power plants, this could also mean that power markets could be slow to react to another California-style price runup.

How is wholesale market performance measured?

Among the principal reasons[54] 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.

This examination of the performance of the wholesale markets 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

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[52]Lawrence Makovich quoted by Chris Baltimore, *Reuters*, "Energy Sector Weakness Could Threaten Power Supplies," July 24, 2002.

[53]Another indicator of this trend is an announcement last July by GE Power, a division of General Electric Co. and manufacturer of power turbines, that said it planed to lay off 2,500 workers now and possibly more next year due to falling sales. Steve Everly, "Power Industry Faces Market Where Supply Has Outrun Demand," The Kansas City Star (MO), August 6, 2002.

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

this ease of entry[55] 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.[56] The price-taking competitive firm that has no market power cannot pick its own price or influence it in any significant way. In extreme cases of market power, such as with a monopolist that faces no threat of entry from rival firms, there are upper bound limits on price that even an unregulated monopolist must contend with. These include 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

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[55]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.

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

sufficiently high that it creates a strong incentive for other firms to find ways around the entry barriers to the market or 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, the full weight and force of the U.S. Department of Justice and the Federal Trade Commission are not likely to be used to correct this market imperfection. Indeed, the corrective action 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 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. And 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.[57] 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,[58] is to either physically or economically withhold output from the market. Physical withholding is the actual withdraw 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.

California

The California wholesale market crisis began in late May of 2000 when the average Power Exchange (PX) price jumped from just over $27 per MWh in April of 2000 to over $50 per MWh in May and then to $132 per MWh in June–on its way to a high of about $450 per MWh in January 2001. The last power emergency occurred in early July of 2001, which can be viewed as the end of the crisis period. After this period, wholesale prices leveled off and did not return to the levels reached during the crisis. The eventual decline in prices was due to the reversing of a similar combination of factors that lead to prices rising during the crisis. These included a return of hydro-capacity, reduced demand, and lower natural gas prices. (The combination of factors that caused the crisis in California is

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[57]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.

[58]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.

discussed in last year's report.) The FERC western-wide price cap was likely imposed too late (June of 2001) to have much of an impact on prices during the crisis.[59] Figure 15 graphs the prices from January 2000 through March 2002.

The California power market has been studied and analyzed more than any other power market in the country. There was evidence before the summer of 2000 suggesting that market power was significant during peak hours. Since growing demand in California was not matched with additional supply and significant existing hydro capacity was unavailable due to drought conditions, there is little doubt that scarcity played a role in the price runup. It would be expected that the price would be driven up to the marginal cost of the highest cost marginal unit needed to satisfy demand–a higher marginal cost than would obtain than during times of relatively plentiful supply. However, it is clear that actual prices exceeded, and often greatly exceeded, the expected highest marginal cost. Empirical evidence of market power has been found in several analyses of the California market. A summary of the more significant studies that were discussed last year are presented again here, followed by summaries of two new analysis of California's markets.

[59]A FERC staff report ("Report on the Economic Impacts on Western Utilities and Ratepayers of Price Caps on Spot Market Sales," a paper prepared by the FERC staff, January 31, 2002) found that "after the Commission [FERC] issued its June 19 [2001] Order, prices in the spot market steadily declined throughout the time period at issue [late June through late November] and were well below the $92/MWh price cap." (p. 11.) The report concluded that "a wide variety of factors other than the price cap, such as conservation efforts, a downturn in the regional economy, and adequate supply given low demand, affected sales prices in both the spot and non-spot markets." (p. 4.)

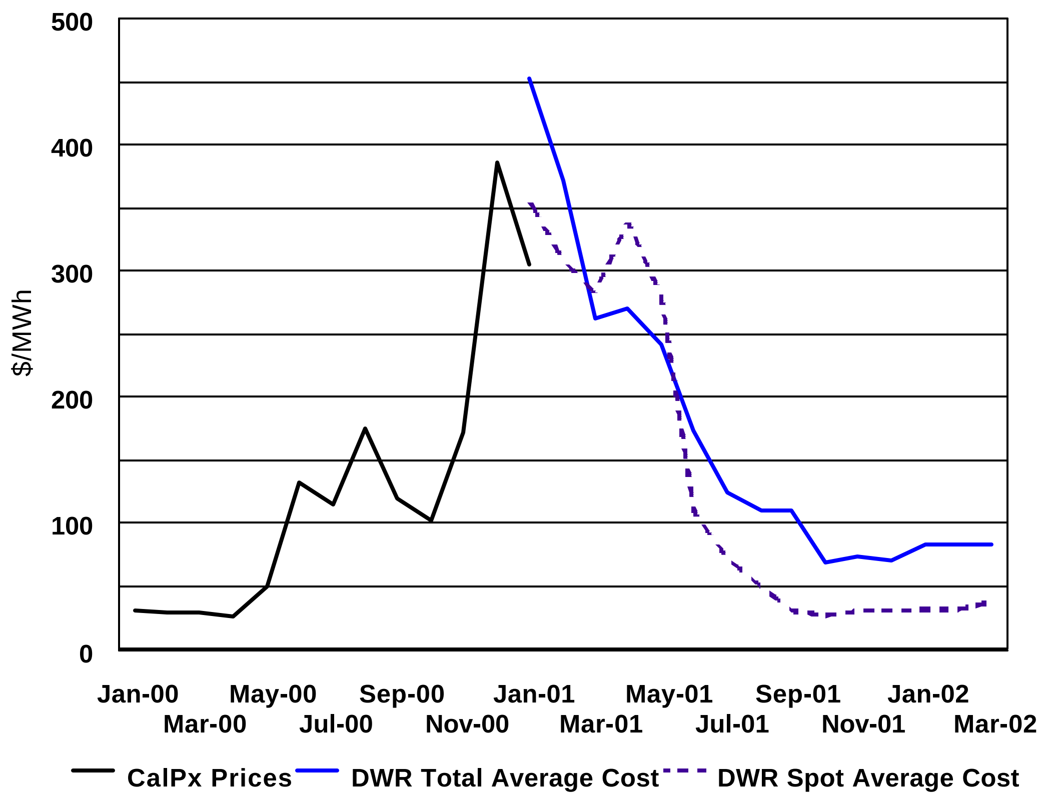

Figure 15. California power prices during the 2000 - 2001 crisis.

Before the California crisis of 2000 and 2001 began, a study by Borenstein, Bushnell, and Wolak[60] had found evidence of significant market power in the California wholesale electricity market. They estimated total payments in excess of competitive levels at $719 million for the 16 months of their study period–June of 1998 to September of 1999. If June of 1998 is excluded, the total payment in excess of competitive levels was

[60]Borenstein, Bushnell, and Wolak, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market," working paper of the Program on Workable Energy Regulation, University of California Energy Institute, Berkeley, California, March 2000, PWP-064.

determined to be $795 million.[61] They calculated the average markup of price over a competitive outcome at 15.7 percent or, excluding June '98, 18.3 percent. This markup occurred primarily during peak demand periods.

Dr. Anjali Sheffrin, the Director of the Department of Market Analysis of the California Independent System Operator, conducted a detailed analysis of market power and bidder strategy in California. [62] This study provides evidence that "many large suppliers actively engaged in strategic bidding efforts and that their activity had a direct impact on market prices." Dr. Sheffrin concludes that supplier "bidding strategy was not ad hoc, but consistent with a certain model of oligopoly pricing behavior" and that it "implies the systematic exercise of market power to maximize profit." Her findings are consistent with expected behavior of firms with considerable market power that can profitably use economic and physical withholding to raise prices. Five large in-state suppliers were found to use economic withholding 80 percent of the time and physical withholding less than 20 percent of the time. Her estimated average bid-cost markup was more than $100/MWh during some summer months. The total market power impact was estimated at approximately $6.2 billion from May of 2000 through February of 2001.

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[61]As a later study (discussed below) also shows, June of 1998 had prices *below* competitive levels. This was the third month of operation of the California Power Exchange and most of the capacity was still owned by the investor-owned utilities. During this time, the utilities' competition transition charges (CTCs) were calculated as the previous regulated rate minus the mandated discount, transmission and distribution charges, other customer charges, *and the Power Exchange price* (adjusted for customer class). This meant that the lower the PX price, the greater the CTC. After divestiture by the utilities and other suppliers entered the market, this incentive was removed.

[62]Anjali Sheffrin, "Empirical Evidence of Strategic Bidding in California ISO Real Time Market," March 21, 2001, California Independent System Operator and "What Went Wrong With California Electric Utility Deregulation?," presentation at "Current Issues Challenging The Utility Industry," held by the Center for Public Utilities, New Mexico State University, Santa Fe, New Mexico, March 26, 2001.

An analysis by Joskow and Kahn,[63] concludes that wholesale electricity prices in California "far exceeded" competitive levels from June through August of 2000. They could not explain the prices as the "natural outcome of 'market fundamentals' in competitive markets." This was due to the "very significant gap between actual market prices and competitive benchmark prices that take account of these market fundamentals." They estimate a competitive benchmark price of $62.6 per MWh for June 2000 (assuming a NOx price of $10/lb), which compares with the average PX price for the month of $120.2 per MWh. For July the competitive benchmark was $67.98 per MWh ($20/lb NOx price) and a average PX price of $105.72 per MWh. August and September competitive benchmark prices were $121.5 and $104.36 per MWh (both using a NOx price of $35/lb) respectively, when average PX prices were $166.24 in August and $114.87 in September. The market fundamentals accounted for in their analysis included higher natural gas and emission permit prices, increased demand, and reduced availability of imports. They also found evidence that suggests that the higher prices reflected the withholding of supplies by generators and marketers.

In a recent study, Borenstein, Bushnell, and Wolak[64] estimated the monthly Lerner index for California from June 1998 through October 2000. These estimates are shown in Figure 16. The negative values in the first year of the ISO's operation were likely due to incentives of the investor-own utilities (that still owned most of their per-restructuring generation) to have low energy prices–and thereby increase their competition transition charges or CTCs (as previously explained in footnote 27). In general, the index peaks during the summer and early fall months when demand is at its peak and supplies are most

[63]Joskow and Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000," an AEI-Brookings Joint Center for Regulatory Studies Working Paper (01-01), January 2001.

[64]Severin Borenstein, James Bushnell, and Frank Wolak, "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market," Center for the Study of Energy Markets, University of California Energy Institute, Berkeley, California, CSEM WP 102, June 2002.

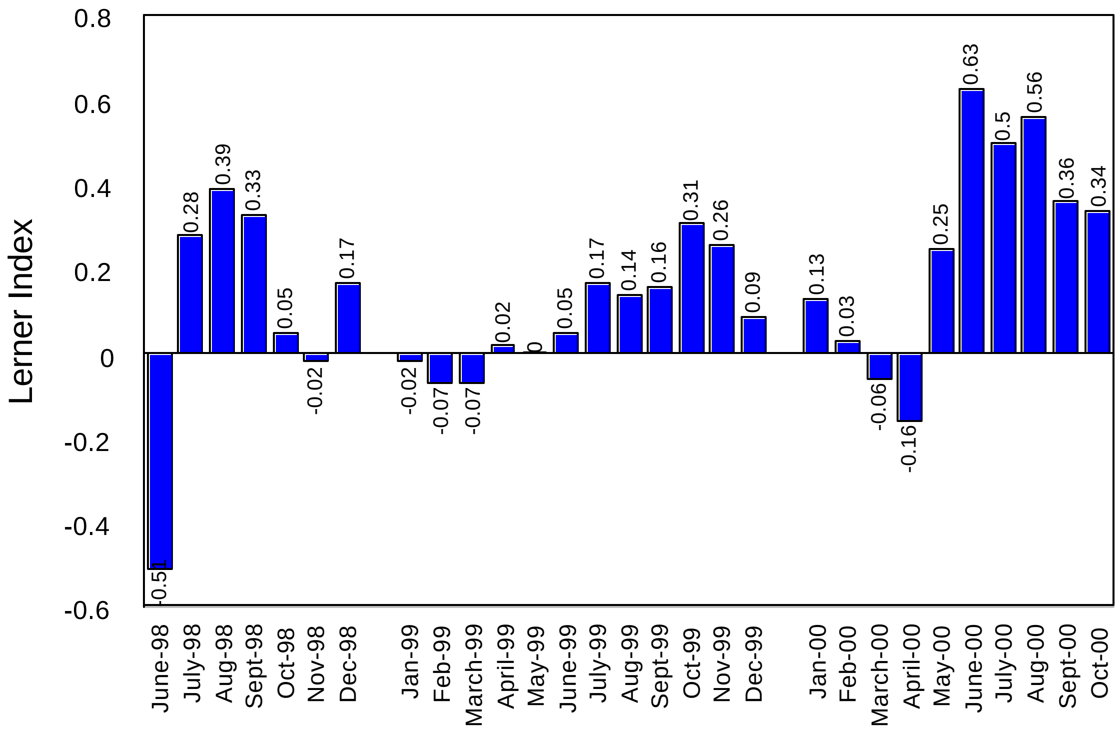

Figure 16. California monthly Lerner Index for June 1998 through October 2000. Source: Borenstein, Bushnell, and Wolak, “Measuring Market Inefficiencies in California’s Restructured Wholesale Electricity Market,” June 2002.

constrained. They also correlated the hourly demand level for electricity with the corresponding Lerner index for that hour,[65] their results are shown in Figure 17. This clearly demonstrates that as demand increases, when supplies become increasingly scarce, the ability of suppliers to leverage a higher price increases. At its peak, the index is over 0.5 (that is, 50 percent of the price is markup above marginal cost) in all three years. At only about two-thirds of the peak demand, however, the index is above 0.3 for all years. At lower levels of demand, as would be expected, suppliers have very little price leverage. It is interesting to note that all three years, including the crisis year of 2000, have a similar overall pattern. This confirms the expectation discussed above that when demand is relatively inelastic (that is, unresponsive to price as electricity generally is), the

[65]They used “kernel” regression to determine the curves for each year.

market is concentrated as they were in California at that time, and as the supply from other firms becomes more restricted as demand increases, the price leveraging ability of firms increases.

Borenstein, Bushnell, and Wolak also estimated supplier economic rents[66] due to the exercise of market power in California. They estimate that between the summers of 1998 and 2000, "oligopoly rents," increased more than ten fold, from $425 million in 1998 to $4.45 *billion* in 2000 (the 1999 estimate was $382 million). They note that while a substantial portion of the rise in the wholesale cost of power, from $1.67 billion to $8.98 billion, was due to rising input costs and reduced imports, this also increased the amount of the market power exercised by suppliers as well.

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[66]Economic rent is defined as what was paid to producers beyond what would have been the minimum amount required to have them continue to generate electricity.

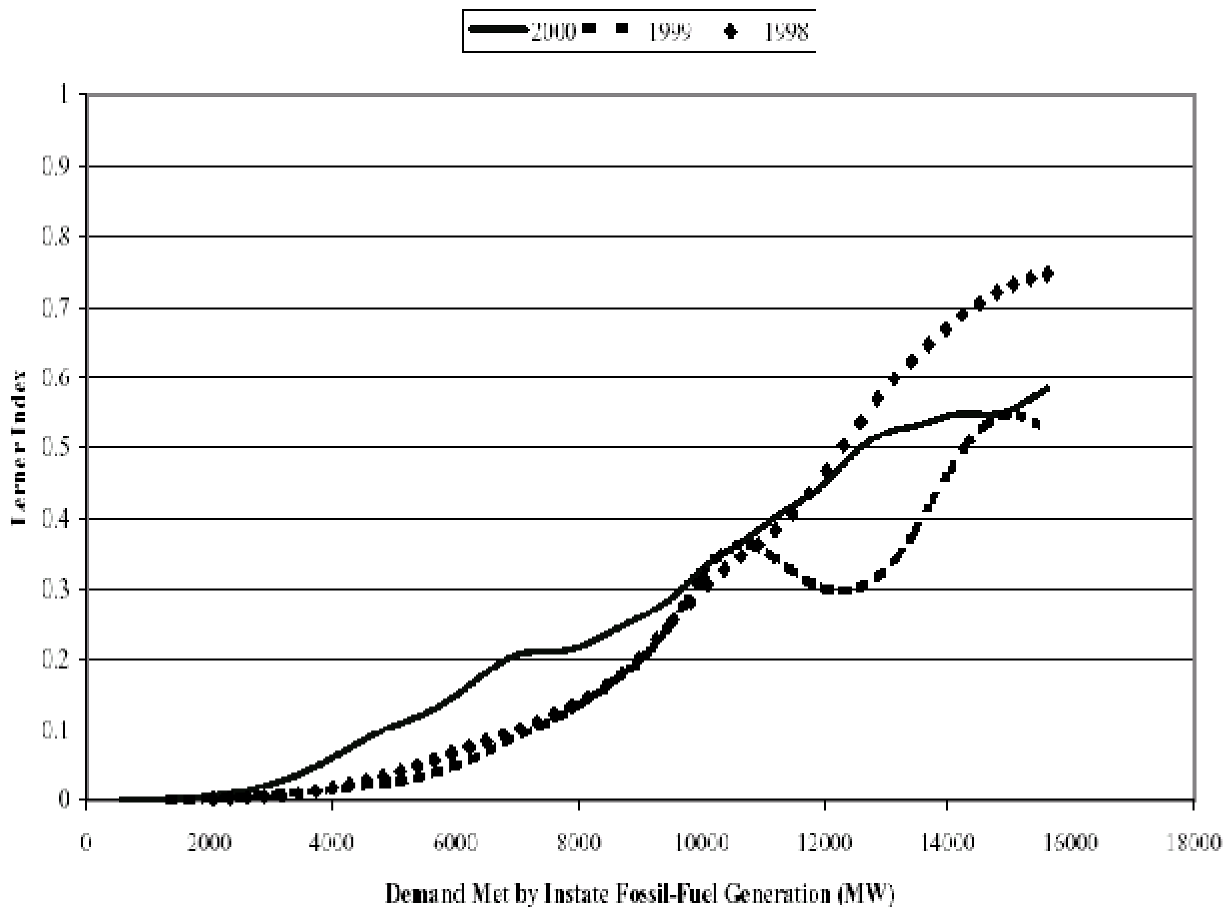

Figure 17. The relationship between the level of demand and the Lerner Index (market power markup estimate) for California.
Source: Borenstein, Bushnell, and Wolak, "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market," June 2002.

An analysis by the California ISO[67] also shows that electricity suppliers in California exercised significant market power and were able to raise prices significantly above competitive levels. Figure 18 shows the markup of prices above a competitive market for the forward and real-time energy markets in California during 2000 and 2001. The area depicted in red is the estimated supplier market power markup. The California ISO's

[67] California Independent System Operator, "Third Annual Report on Market Issues and Performance: Market Monitoring, Investigative, and Compliance Activities," January – December 2001, January 2002.

report notes that the bulk of the markup observed after June is embedded in the long-term forward contracts entered into by the California Energy Resource Scheduler (CERS) during January through April 2001. Market power, they note, is therefore embedded in the long-term average costs for electricity. Supplier market power in the real-time market was substantially reduced after June of 2001, as shown in Figure 19. They note that this is because of more favorable supply/demand conditions, the imposition of a regional (western-wide) price cap by FERC, and forward purchases by the state.

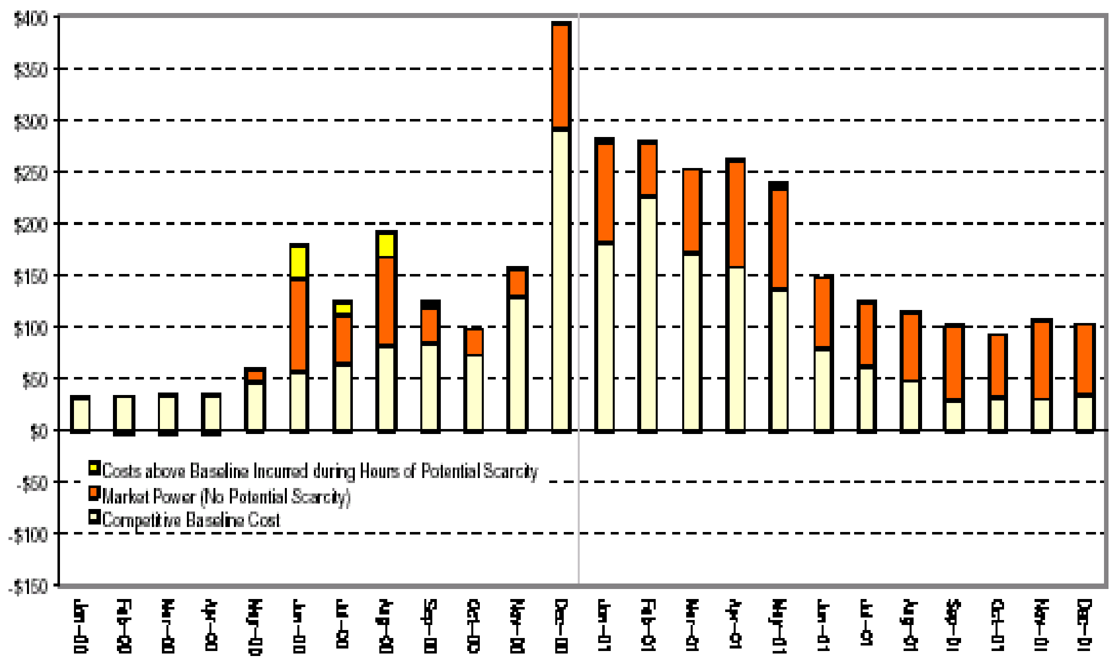

Figure 18. Price-cost markup of forward and real-time energy.
Source: California Independent System Operator, "Third Annual Report on Market Issues and Performance Market Monitoring, Investigative, and Compliance Activities," January – December 2001, January 2002.

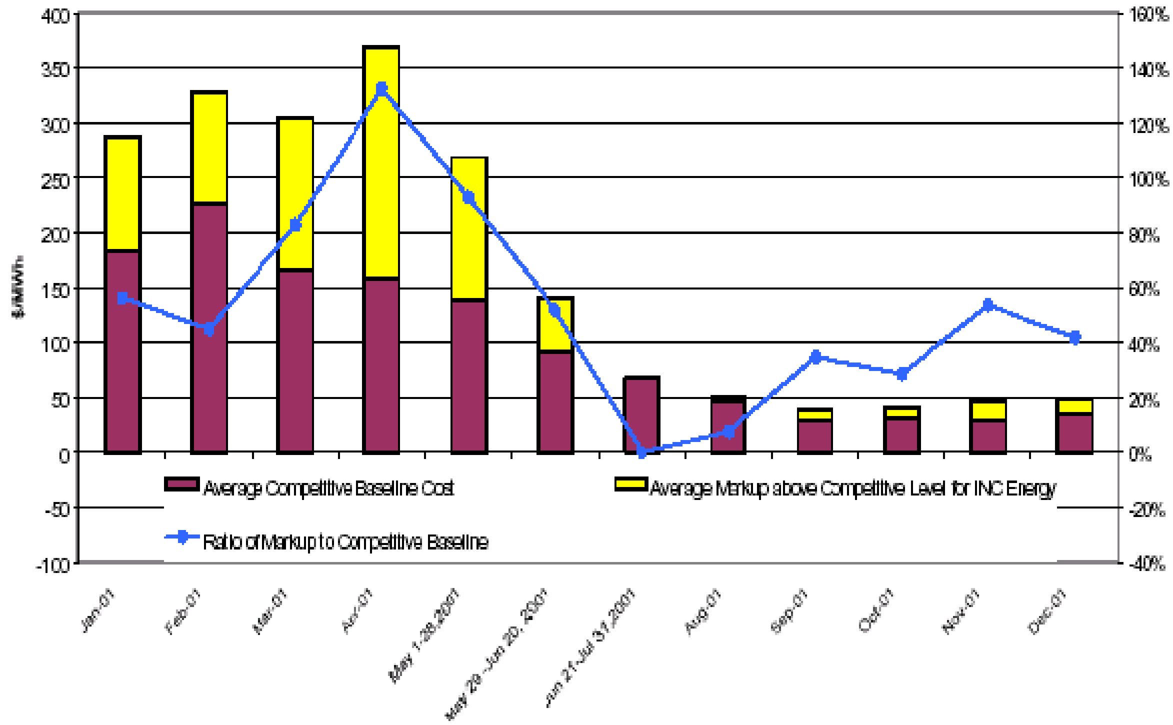

Figure 19. Price-cost markup in the real-time energy market.
Source: California Independent System Operator, "Third Annual Report on Market Issues and Performance Market Monitoring, Investigative, and Compliance Activities," January – December 2001, January 2002.

New England

A study of the New England ISO market by Bushnell and Saravia[68] used a similar "competitive benchmark analysis" as was used in the June 2002 Borenstein, Bushnell, and Wolak analysis. The competitive benchmark is the estimated price that would result if all firms acted as price-taking firms–that is, no firm exercises market power.[69] The study examined the period of May 1999 through September 2001. The results of the Lerner index estimation are summarized in Figure 20 (this is the estimation using ISO-NE Energy Clearing Prices). The results are similar to the California estimation (Figure 16) with relatively higher indices during the summer months, but without sustained periods of very high monthly markups lasting several months.

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 21. The graph is flatter than for California for a wider range of demand, indicating that for up to moderate levels of demand the Lerner index (and market power markup) is lower. However, at high levels of demand, the index rises quickly and reaches values that are similar to the California result. A comparison of California, New England, and PJM is presented later in this section of the report.

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 proceedings. The pending

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[68] 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.

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

expiration of transition periods and potential consolidation of supply portfolios will reverse this effect.[70]

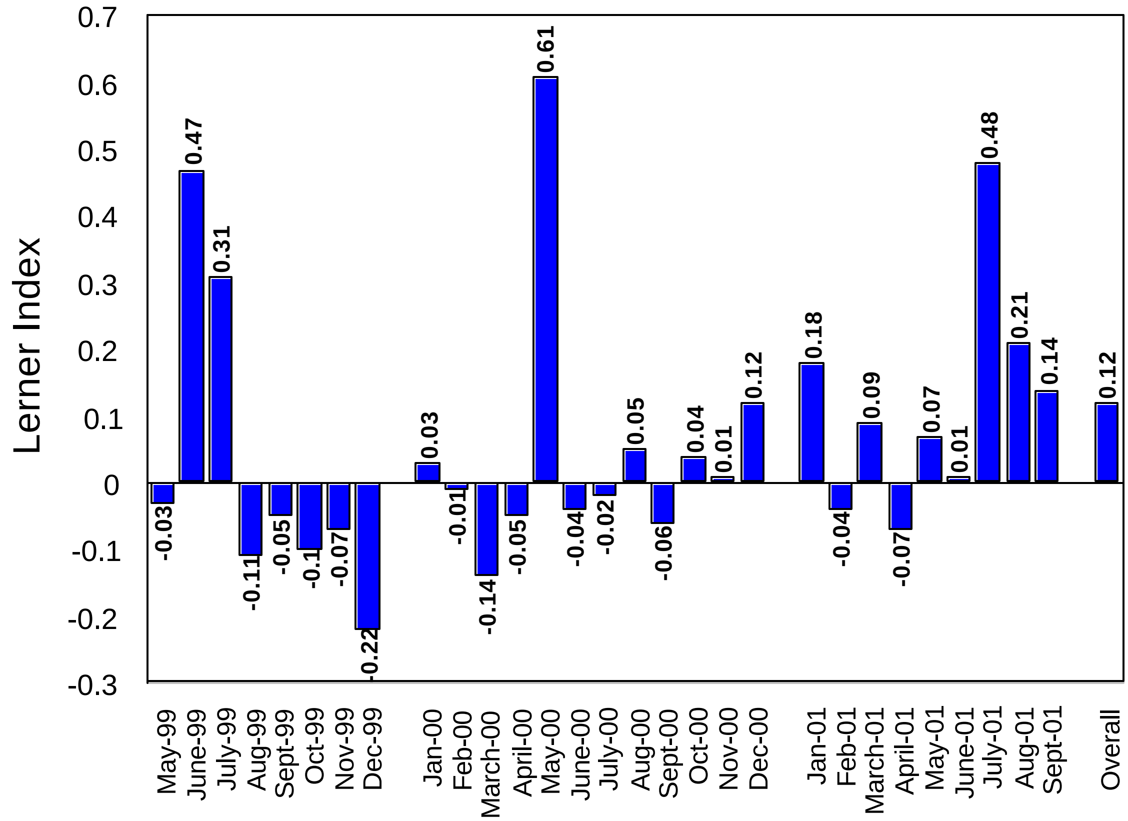

Figure 20. Monthly Lerner index for New England electricity market, May 1999 to September 2001.
Source: Bushnell and Saravia, “An Empirical Assessment of the Competitiveness of the New England Electricity Market,” May 2002.

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[70]Bushnell and Saravia, p. 21.

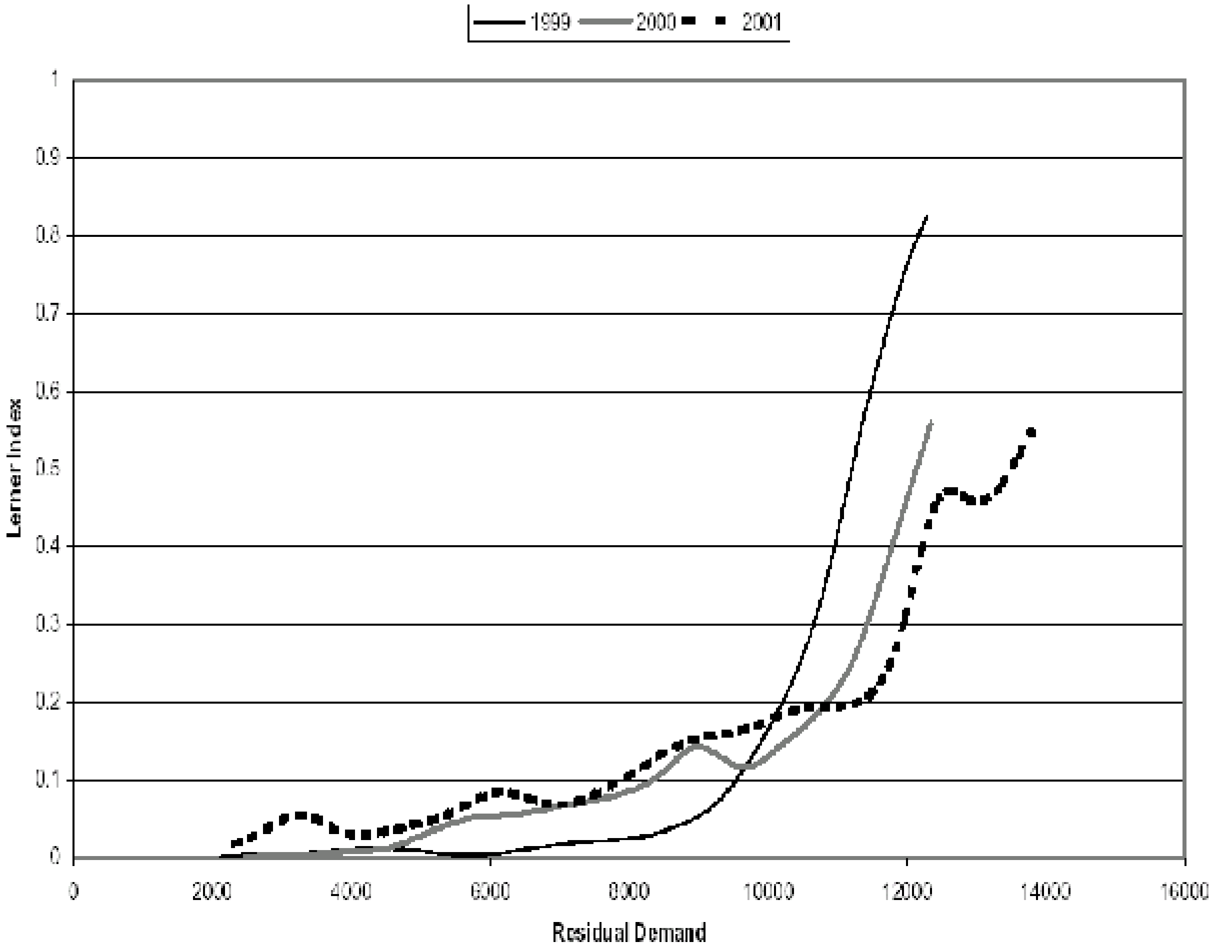

Figure 21. The relationship between the level of demand and the Lerner index for New England.
Source: Bushnell and Saravia, “An Empirical Assessment of the Competitiveness of the New England Electricity Market,” May 2002.

New England ISO's monthly weighted average prices are shown in Figure 22. Daily and peak hourly weighted average prices are shown in Figure 23 for July 2001 through June 2002. The impact on prices from the hot weather in late July and early August of 2001 can clearly be seen.

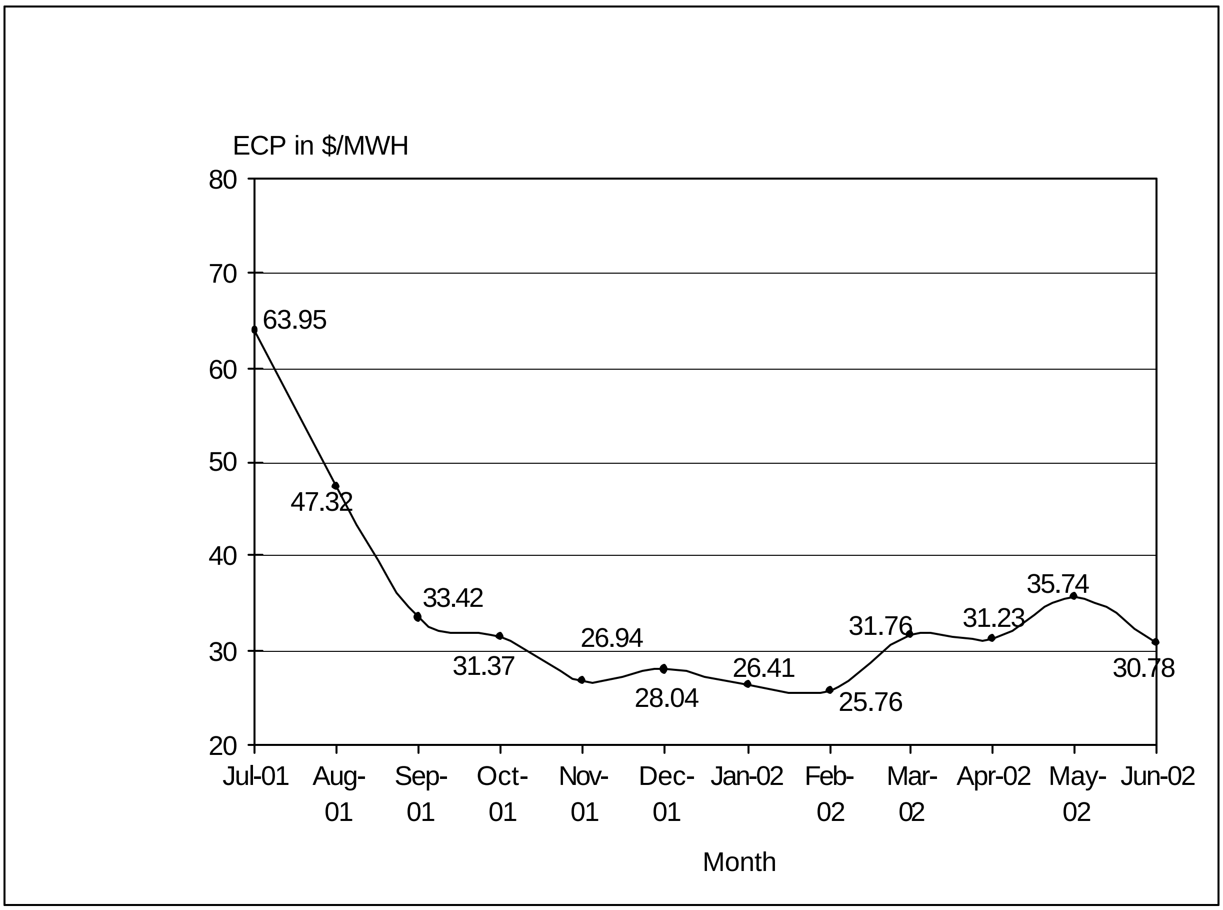

Figure 22. New England ISO Weighted Average Energy Clearing Prices.

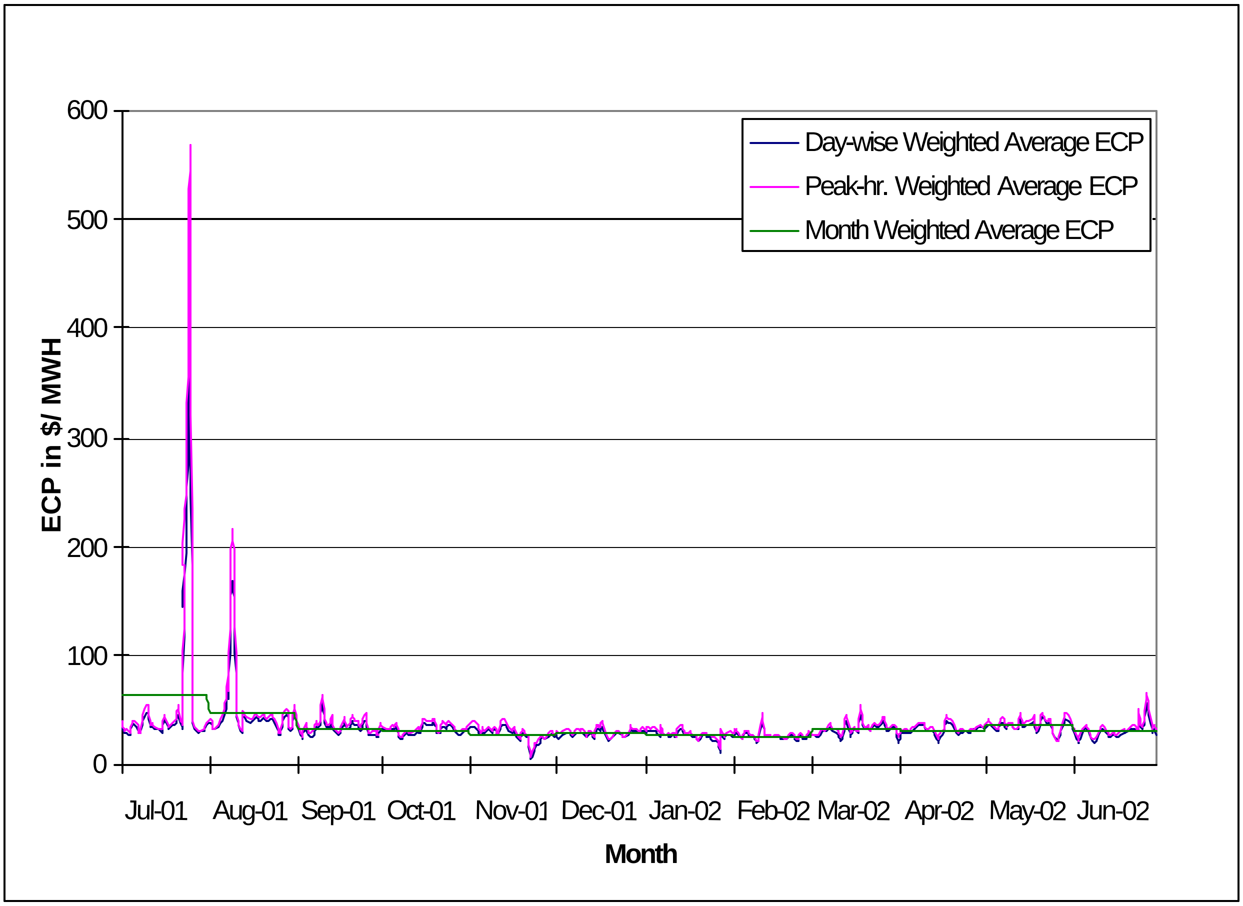

Figure 23. New England ISO Energy Clearing Prices.

PJM

In an analysis summarized in last year's report, it was noted that Erin T. Mansur[71] had found that market imperfections in the PJM spot energy market (which account for 10 percent to 15 percent of the market) for the period April through August of 1999 totaled $224 million. She estimated that total costs in PJM were 41 percent higher than would have occurred with perfect competition. When bilateral contracts are added (an additional 30 percent of the market) the sum of the spot market and bilateral contract costs is $827 million, or a 48 percent increase over competitive costs. She calculated a load-weighted Lerner Index of 0.293 (29 percent of the price) for the spot energy market and 0.323 (32 percent) when bilateral contracts are included.[72] These were considerably larger than PJM's Market Monitoring Unit's (MMU) estimate of an average markup of about 0.02 (2 percent) for April through December of 1999 and the year's maximum markup in July of 0.08 (8 percent).

In this year's PJM MMU's report of the year 2000,[73] the markups or Lerner indices are again much lower than Mansur's or as seen in other markets. The average markup for 2001 was calculated to be 0.02 (2 percent), with a maximum monthly markup of 0.05 (5 percent) for January and a minimum of less than 0.01 (less than 1 percent) for November. They also calculate 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

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[71]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.

[72]Her methodology is similar to Borenstein, Bushnell, and Wolak, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market" and Wolak, "What Went Wrong with California's Re-structured Electricity Market?"

[73]Market Monitoring Unit, PJM Interconnection, L.L.C, "PJM Interconnection State of the Market Report 2001," June 2002.

10 percent increase over cost and results in the average markup for 2001 to increased to 0.11 (11 percent) with a monthly maximum of 0.13 (13 percent) in January and a minimum of 0.09 (9 percent) for October.

It appears that these markup calculations are based on "cost-based offers" as the marginal cost rather than an estimate of marginal cost based on the resource costs, as others have done.[74] If this is the case, then this will likely understate the markups (or Lerner) index.[75] This is because suppliers are bidding an offer price that is not necessarily their marginal cost. A supplier with market power will, by definition, bid at a price that is above their marginal cost. Since marginal cost is usually not known directly, it can be estimated based on resource costs (fuel, operation and maintenance costs, etc.) of production. For example, Bushnell and Saravia (May 2002) estimate a "competitive benchmark" for the marginal cost, which is the estimated market price if there was a perfectly competitive market. This is estimated to be the incremental cost[76] of the lowest cost unit that is not needed to serve demand.

The MMU concluded that there was an exercise of market power in PJM's capacity credit markets (the "ICAP" market) during the first quarter of 2001.[77] Load Serving Entities in PJM must either have their own capacity or purchase capacity credits from a supplier that does own capacity. If a Load Serving Entity does not have their own capacity or the

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[74]An inquiry was sent to a PJM representatives to clarify this calculation (plus an appeal to a second representative for a response from the MMU). No response has been received.

[75]Recall that the markup or Lerner index is calculated as:
(Price - Marginal Cost)/Price. If the marginal cost is overestimated, the markup will be understated.

[76]Since actual marginal cost is unknown, "incremental cost" is used to refer to the estimated marginal cost based on the resource costs of production.

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

capacity credits, then they must pay a Capacity Deficiency Rate of $177.30 per MW-day. During the summer of 2000 and early in 2001, prices in the daily capacity credit market jumped from zero or near zero to about $177, the Capacity Deficiency Rate, as shown in Figure 10. During this time, there were also price spikes to $354 per MW-day–since market rules require the capacity deficient party to pay twice the Capacity Deficiency Rate on a day when the overall market is deficient. The MMU concluded that one supplier ("Entity 1'') was unilaterally able to exercise undue market power during the first quarter of 2001 through the use of economic withholding, that is, withholding capacity by offering the capacity at prices greater than the Capacity Deficiency Rate. The MMU points out that this company held more net capacity than the total excess capacity in the market. The MMU stated that it believed because of changes in the underlying market conditions, actions by market participants, and rule changes proposed by PJM and approved by FERC, prices in the daily, monthly, and multi-monthly markets have declined, as can be seen in Figure 24.

In an "Investigation Report," the Pennsylvania Public Utility Commission[78] concluded:

> that there is reason to believe that anticompetitive or discriminatory conduct including the unlawful exercise of market power and the threat of future recurrences of similar conduct is preventing the retail customers in this Commonwealth [of Pennsylvania] from obtaining the benefits of a properly functioning and workable competitive retail electricity market.[79]

The Commission noted that 36 licensed electric suppliers have exited the Pennsylvania market by surrendering their licenses and only seven have entered.

The Pennsylvania PUC referred the matter to the Pennsylvania Attorney General, the United States Department of Justice, and FERC and authorized the Commission's Law Bureau to intervene in any proceedings.

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[78]Pennsylvania Public Utility Commission, "Investigation Report," Re: Investigation Upon the Commission's Own Motion With Regard to PJM Installed Capacity Credit Markets, Docket No. I-00010090, Public Meeting held June 13, 2002.

[79]Pennsylvania Public Utility Commission, "Investigation Report," pp. 3 - 4.

The capacity credit market's problems combined with the energy market prices in early 2001 clearly caused the drop off in retail market activity in Pennsylvania and other PJM states as described in Part I. 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.[80] When energy prices are over $50/MWh, as it averaged during December of 2000 and again in August of 2001, adding $10/MWh for capacity[81] would place the total cost over $60/MWh or 6 cents/kWh, well above the fixed PECO Energy price to compare. 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.

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

[81]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."

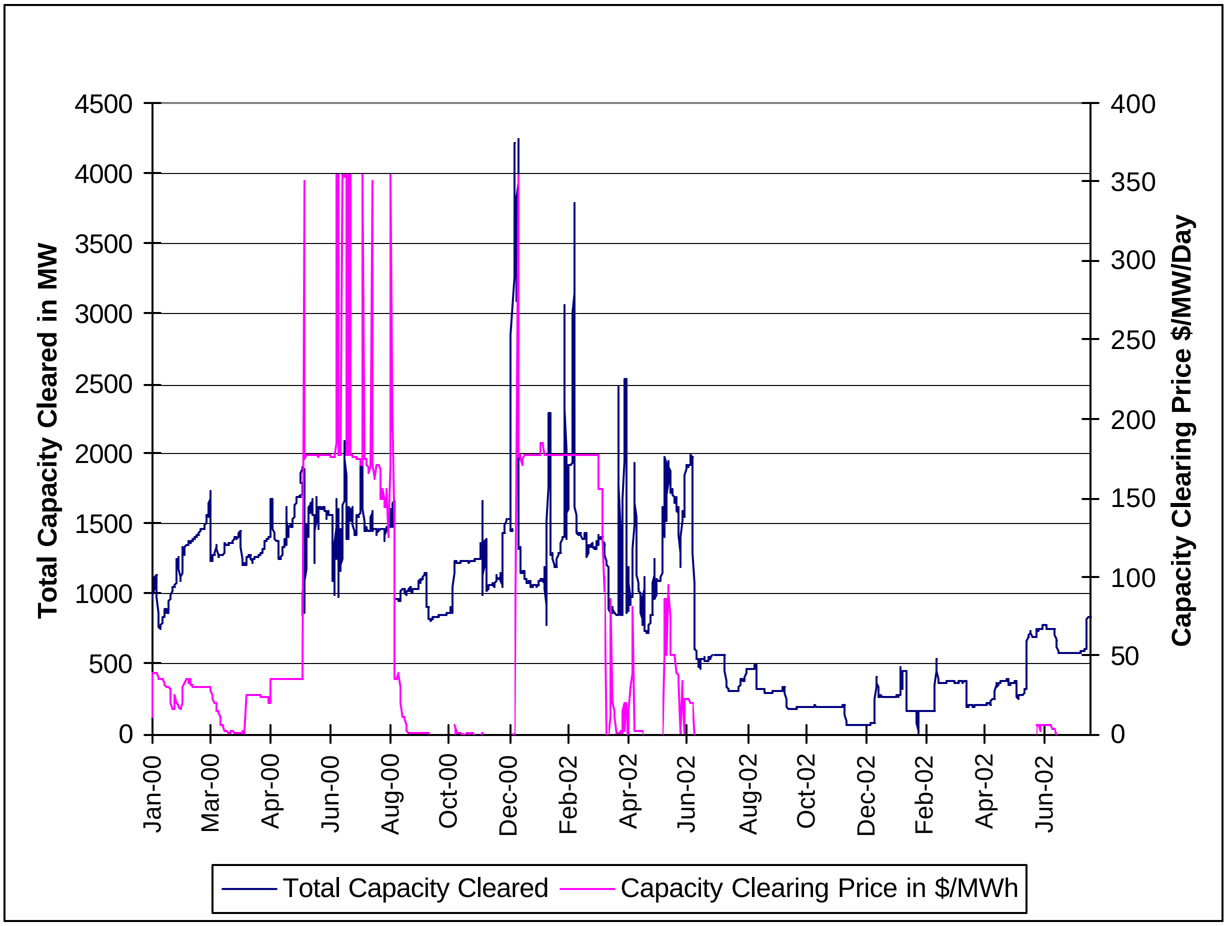

Figure 24. PJM Daily Capacity Credit Market.

Figure 25 compares the capacity ratio (residual demand divided by capacity) and Lerner index relationship for California, New England, and PJM for the same time period of May to December 1999. The California regression line exceeds a Lerner index of 0.2 at about only .35 capacity ratio and is over 0.4 just before .60 capacity ratio is reached. However, while both New England and PJM remain below a Lerner index of 0.1 through about .65 capacity ratio, both regressions lines rise very quickly and exceed a Lerner

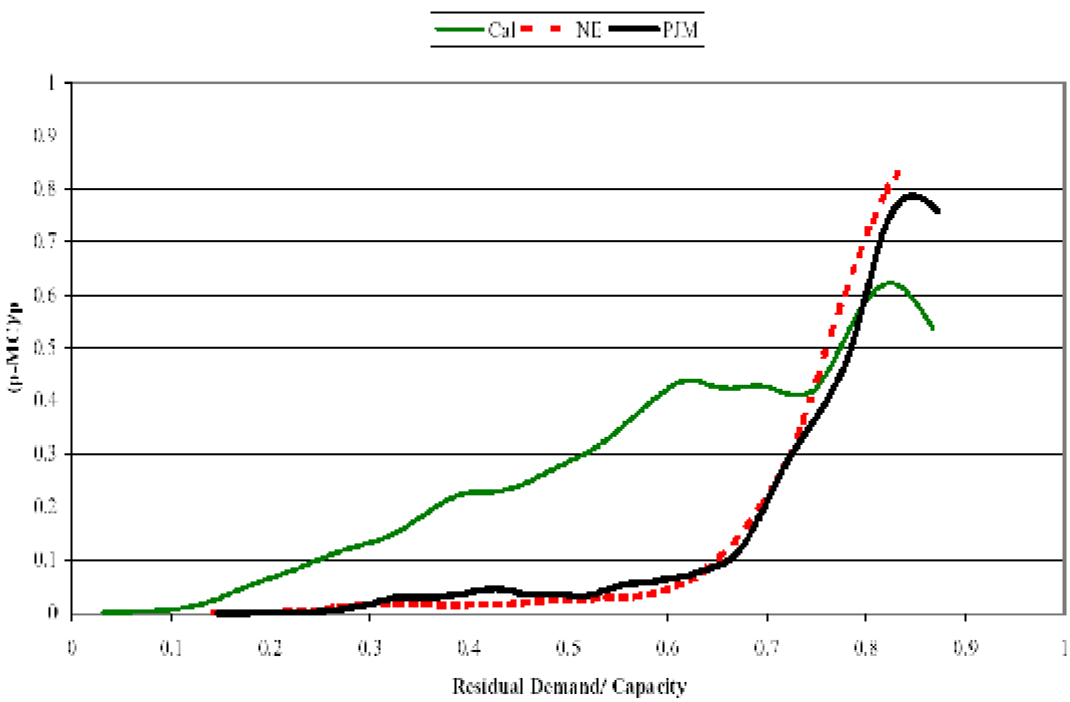

Figure 25. Comparison of California, New England, and PJM relationship between demand level and Lerner index.
Source: Bushnell and Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," May 2002.

index of 0.2 by .70 capacity ratio and reach a higher peak than California's regression line at just over .80 capacity ratio.

PJM's monthly weighted average prices are shown in Figure 26 and daily and peak hour weighted average prices are shown in Figure 27 for July 2001 through June 2002. Here again, the impact on prices from hot weather in late July and early August of 2001 can clearly be seen, as well as April and June of 2002.

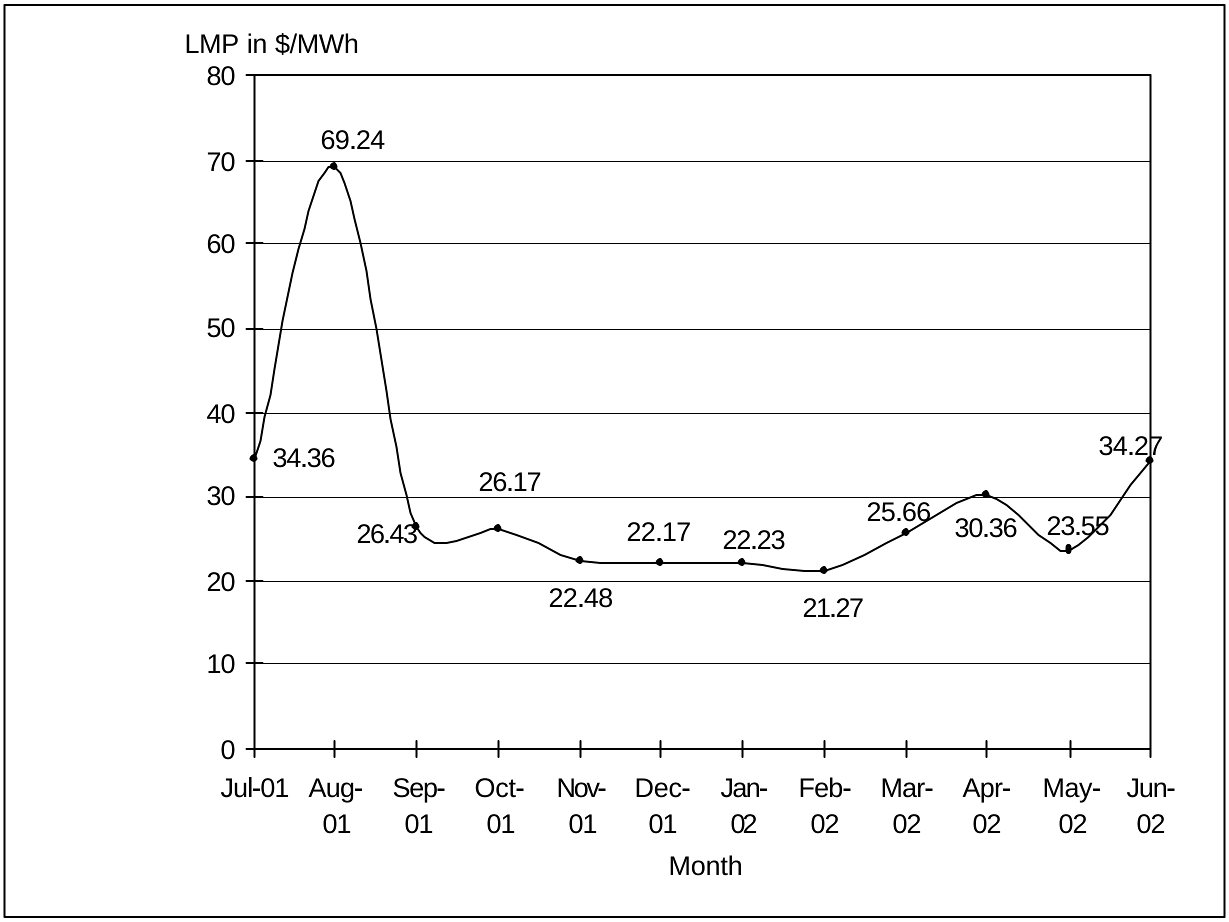

Figure 26. PJM Day Ahead Weighted Average LMPs.

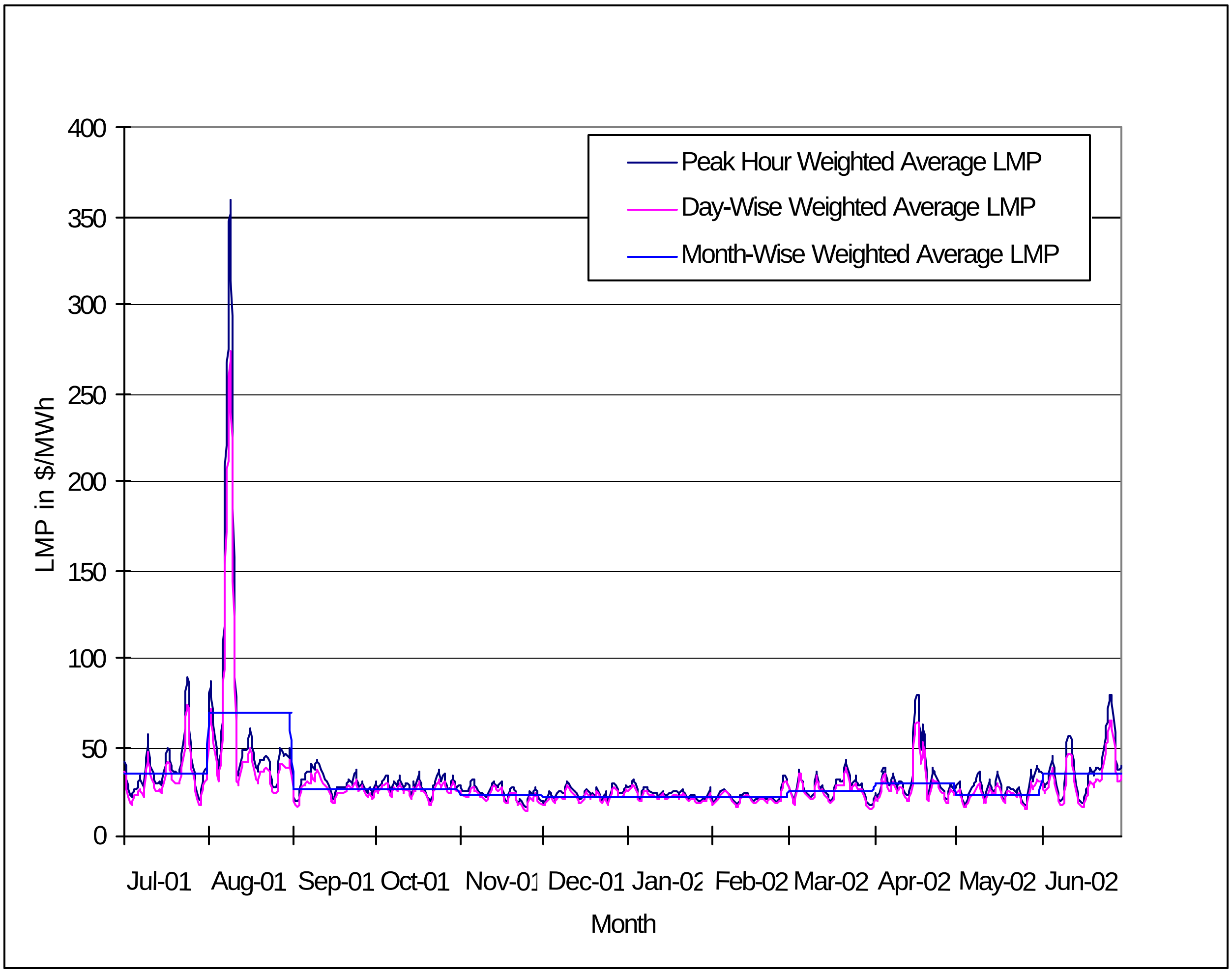

Figure 27. PJM Day Ahead Locational Marginal Prices.

New York

Figure 28 shows the weighted average prices for the New York ISO.

The independent market advisor to the New York ISO stated that markets are "workably competitive, with limited instances of significant withholding or other strategic conduct" and that the New York ISO's "market power mitigation measures were sufficient to address these instances."[82]

The New York ISO has forecasted a need for an additional 7,100 MW of capacity by 2005, with 2,000 to 3,000 MW that must be located in New York City. They believe 750 to 1,000 MW are needed for Long Island "as soon as possible to alleviate severe reliability risks and high prices."[83]

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[82]David B. Patton and Michael T. Wander, "2001 Annual Report on the New York Electricity Markets," June 2002.

[83]New York Independent System Operator, "Power Alert II: New York's Persisting Energy Crisis," March 27, 2002.

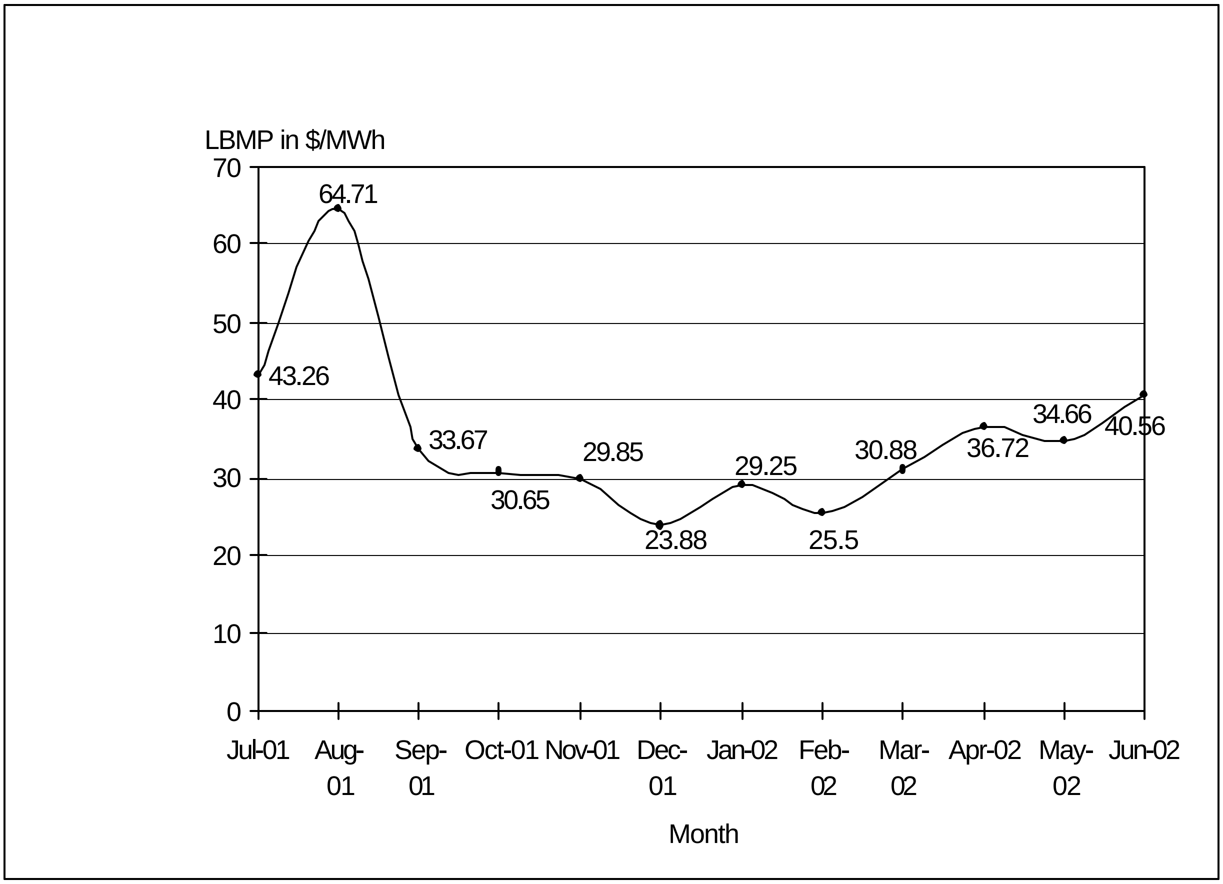

Figure 28. New York ISO Weighted Average Locational-Based Marginal Prices (LBMPs).

Appendix A: Summary of residential offers by state - May 8, 2002.

State and Dist. Company	Renewable offers	Offers from various sources	Long Term Contracts	Offers below price-to-compare	Number of suppliers	Percent savings on lowest offer
Arizona						
▸ Arizona Public Service	0	0	0	0	0	-
▸ Tucson Electric Power	0	0	0	0	0	-
California						
▸ Pacific Gas & Electric	0	0	0	0	0	-
▸ San Diego Gas & Electric	0	0	0	0	0	-
▸ Southern California Edison	0	0	0	0	0	-
Connecticut						
▸ Connecticut Light & Power	3	1	3	1	2	6.91%
▸ United Illuminating	3	1	3	0	2	-
District of Columbia						
▸ Potomac Electric Power Co. (PEPCO)	0	1	1	1	1	Wi - 3% Su - 6%
Delaware						
▸ Conectiv Power	0	0	0	0	0	-
▸ Delaware Electric Coop	0	0	0	0	0	-
Illinois						

State and Dist. Company	Renewable offers	Offers from various sources	Long Term Contracts	Offers below price-to-compare	Number of suppliers	Percent savings on lowest offer
Maine						
▸ Central Maine Power Co.	0	0	0	0	0	-
▸ Bangor Hydro Elect Co.	0	0	0	0	0	-
▸ Maine Public Service Co.	0	1	1	1	1	9.66%
Maryland						
▸ Allegheny Power	0	0	0	0	0	-
▸ Baltimore Gas & Energy	2	0	2	0	1	-
▸ Delmarva Power & Light / Conectiv	0	0	0	0	0	-
▸ Potomac Electric Power Co. (PEPCO)	2	0	2	2	1	9.24%
Massachusetts						
▸ Commonwealth Electric Co.	0	0	0	0	0	-
▸ Cambridge Electric Co.	0	0	0	0	0	-
▸ Western Mass Electric Co.	0	0	0	0	0	-
▸ Boston Edison Co.	0	0	0	0	0	-
▸ Fitchburg Gas & Electric Light Co.	0	0	0	0	0	-
▸ Massachusetts Electric Co.	0	0	0	0	0	-

State and Dist. Company	Renewable offers	Offers from various sources	Long Term Contracts	Offers below price-to-compare	Number of suppliers	Percent savings on lowest offer
Michigan						
▸ American Electric Power Company	0	0	0	0	0	-
▸ Alpena Power Company	0	0	0	0	0	-
▸ Consumers Energy Company	0	0	0	0	0	-
▸ Detroit Edison Company	0	0	0	0	0	-
▸ Edison Sault Electric Company	0	0	0	0	0	-
Montana						
▸ Montana Power Co.	0	0	0	0	0	-
New Hampshire						
New Jersey						
▸ GPU/Jersey Central Power & Light Co.	1	0	0	0	1	-
▸ Atlantic City Energy Co./Conectiv	1	0	0	0	1	-
▸ Public Service Electric & Gas Co.	1	1	1	0	2	-

State and Dist. Company	Renewable offers	Offers from various sources	Long Term Contracts	Offers below price-to-compare	Number of suppliers	Percent savings on lowest offer
New York						
▸ Central Hudson Gas & Electric Corp.	0	0	0	0	0	-
▸ Consolidated Edison Co. of New York	0	3	2	0	3	-
▸ New York State Electric & Gas Corp.	0	1	0*	1	1	Upto 5%
▸ Niagara Mohawk Power Corp.	0	1	0*	1	1	Upto 5-6%
▸ Orange & Rockland Utilities	0	0	0	0	0	-
▸ Rochester Gas & Electric Corp.	0	2	0*	2	2	5.41%
Ohio						
▸ AEP/Columbus Southern Power Co.	0	0	0	0	0	-
▸ AEP/Ohio Power Co.	0	0	0	0	0	-
▸ Cincinnati Gas & Electric Co.	0	1	1	1	1	7.02%
▸ Dayton Power & Light	0	0	0	0	0	-
▸ First Energy/Illuminating Co.	0	0	0	0	0	-
▸ First Energy/Ohio Edison Co.	0	1	1**	1	1	3.50%
▸ First Energy/Toledo Edison Co.	0	1	1**	1	1	3.50%

State and Dist. Company	Renewable offers	Offers from various sources	Long Term Contracts	Offers below price-to-compare	Number of suppliers	Percent savings on lowest offer
Pennsylvania						
▸ Allegheny Power	3	0	0	0	2	-
▸ Duquesne Light Co.	4	1	1	0	4	-
▸ GPU/Metropolitan Edison Co.	3	0	0	0	2	-
▸ PECO	7	2	4	3	7	7.21%
▸ GPU/Pennsylvania Electric Co.	3	0	0	0	2	-
▸ Pennsylvania Power Co.	4	0	1	0	3	-
▸ Pennsylvania Power & Light	3	0	0	0	2	-
▸ UGI Utilities	3	0	0	0	2	-
Rhode Island						
▸ Narragansett Electric Power Co.	0	0	0	0	0	-
Texas						
▸ Central Power and Light	1	7	5	4	5	6.81%
▸ Reliant Energy	1	11	6	9	9	7.19%
▸ TXU Electric& Gas	2	11	7	9	9	11.51%
▸ TXU SESCO	0	0	0	0	0	-
▸ Texas New Mexico Power Company	2	4	1	2	5	3.00%
▸ West Texas Utilities	0	6	4	5	3	9.91%

State and Dist. Company	Renewable offers	Offers from various sources	Long Term Contracts	Offers below price-to-compare	Number of suppliers	Percent savings on lowest offer
Virginia						
▸ AEP Virginia	0	0	0	0	0	-
▸ Allegheny Power/Potomac Edison	0	0	0	0	0	-
▸ Connectiv	0	0	0	0	0	-
▸ Dominion Virginia Power***	0	0	0	0	0	-
TOTAL	49	56	34	44	75	--

Number of distribution companies with price below to compare : 16

Source: Date compiled from the Wattage Monitor (http://www.wattagemonitor.com), May 2002.

* Energy Cooperative of New York is offering a variable, monthly rate with savings of up to 5-6% in the service territory of Niagara Mohawk Power Corp. and up to 5% in NYSEG and Rochester Gas & Electric Company.

** First Energy Services is offering a 12 month variable rate contract with 3.5% savings off current price to compare in the service territories of First energy/Ohio Edison Company and First Energy/Toledo Edison Company.

*** Dominion Virginia Power had two renewable offers earlier this year.

Appendix B: State-by-State Summary of Rate Freeze Expirations and Rate Reductions.

State and Distribution Company Name	End of Rate Freeze	Rate Reduction Summary
Arizona		
Tucson Electric Power	December 31, 2008	1% rate reduction retroactive to July 1, 1999 and another 1% reduction on July 1, 2000
Arizona Public Service	July 1, 2004	7.5% rate reduction over four years for residential customers and 5% over three year period for large customers
District of Columbia		
Potomac Electric Power Company(PEPCO)	Until January 1, 2007 for low and moderate income customers and until January 1, 2005 for all other residential and commercial customers	7% rate reduction for residential customers and 6.5% reduction in rates for commercial customers to be implemented in three phases.
Delaware		
Connectiv	Four year rate freeze	Rate cut of 7.5% for residential customers
Delaware Electric Cooperative	Five year rate freeze	They received 5% rate reduction
Illinois		
AmerenCIPS	Until 2007	Residential rates were reduced by 5% on August 1, 1998 and on October 1, 2000. On October 1, 2002 rates will be further reduced either 5% or the percent by which the rates exceed the 1999 Midwest average, whichever is less.

AmerenUE	Until 2007	Residential rates were reduced by 5% on August 1, 1998 and on October 1, 2000. On October 1, 2002 rates will be further reduced either 5% or the percent by which the rates exceed the 1999 Midwest average, whichever is less.
Central Illinois Light Co.	Until 2007	Residential rates were reduced by 2% on August 1, 1998 an additional by 2% on October 1, 2000.This will be further reduced by another 1% on October 1, 2002.
Commonwealth Edison	Until 2007	Residential rates were reduced by 15% on August 1, 1998 and by 5% on October 1, 2001.
Illinois Power	Until 2007	Residential rates were reduced by 15% on August 1, 1998 and by 5% on May 1, 2002.
Maine		
Central Maine	SOS until March 1, 2005	Reductions from 2.5% to 15%
Bangor Hydro-electric	SOS until March 1, 2005	Reductions of approximately 2.5%
Maine Public Service Co.	SOS until March 1, 2005	Reductions of approximately 8%
Maryland		
Allegheny	For residential customers through Jan 1, 2008, Non-residential rates through January 1, 2004 and T&D till Jan 1, 2004	Res. Customers about 7% base rate reduction
Baltimore Gas & Energy	For six years i.e until June, 2006 for residential customers and for four years for non-residential customers	Residential customers 6.5% rate reduction
DPL/Connectiv	Until June 30, 2004 for residential customers and until June 30, 2003 for non-residential customers	Residential customers 7.5% rate reduction
Potomac Electric Power Company(PEPCO)	Until June 30, 2003 for residential customers	Residential customers 3% rate reduction

Massachusetts		
Eastern Edison	SOS until March 2005	Minimum 10% reduction of the entire bill for all customers on SOS
Commonwealth Electric	SOS until March 2005	Minimum 10% reduction of the entire bill for all customers on SOS
Cambridge Electric	SOS until March 2005	Minimum 10% reduction of the entire bill for all customers on SOS
Northeast Utilities(Western MA Electric Co.)	SOS until March 2005	Minimum 10% reduction of the entire bill for all customers on SOS
Boston Edison	SOS until March 2005	Minimum 10% reduction of the entire bill for all customers on SOS
Fitchburg Gas and Electric	SOS until March 2005	Minimum 10% reduction of the entire bill for all customers on SOS
Massachusetts Electric Company	SOS until March 2005	Minimum 10% reduction of the entire bill for all customers on SOS

Michigan		
American Electric Power Company	Capped until 2013	5% rate reduction
Alpena Power Company	Capped until 2013	5% rate reduction
Consumers Energy Company	Dec 31, 2003 for residential customers, small business consumers rates through 2004 and for large commercial and industrial through 2003 and rates will not be increased until either PSC determines that the distribution utility controls less than 30% of the particular market	5% rate reduction
Detroit Edison Company	Dec 31, 2003 for residential customers, small business consumers rates through 2004 and for large commercial and industrial through 2003 and rates will not be increased until either PSC determines that the distribution utility controls less than 30% of the particular market	5% rate reduction

Edison Sault Electric Company	Capped until 2013	5% rate reduction
New Jersey		
Connectiv	Price reductions must be maintained for 4 years after the start of the competition	5% initial reduction and additional 5% over the next three years
GPU	Price reductions must be maintained for 4 years after the start of the competition	5% initial reduction and additional 5% over the next three years
PSE&G	Price reductions must be maintained for 4 years after the start of the competition	5% initial reduction and additional 5% over the next three years
Rockland	Price reductions must be maintained for 4 years after the start of the competition	5% initial reduction and additional 5% over the next three years
New York		
Central Hudson	Frozen at 1993 rates through June 30, 2001	Large industrial customers who remained with Central Hudson for generation services received 5% per year rate reductions
Consolidated Edison	Industrial customer rate reduction would remain in force for five years	Industrial customers received 25% rate reduction and all other customers 10% over a five year period
New York State Electric and Gas(EnergyEast)	Residential and small commercial customers and industrial customers have had their rates frozen at current levels for two years.	Residential and small commercial customers and industrial customers have had their bills reduced 1% in the third year of the plan, and a total decrese of 5% by the fifth year of the plan. Large commercial and industrial customers received a 5% per year rate decrease for five years.
Niagara Mohawk Power Corp.	NA	Residential and commercial customers were to have a decrease of 3.2% phased in over three years. Industrial customers were to have a decrease of approximately 13%. Overall average decrease is of 4.3%.

Orange & Rockland Utilities	NA	Residential customers received 4% decrease in 1995 and 1996 and an additional 1% in Dec 1997 and Dec 1998. Industrial and commercial customers received rate reductions of 4-14% and large industrial customers received an additional 8.5% in Dec 1997.
Rochester Gas and Electric	NA	Residential and small commercial customers received 7.5% rate decrease. Other commercial customers and most industrial customers received an 8% decrease and large industrial customers 11.2% decrease. All decreases are phased in over 5 years
Ohio		
AEP/Ohio Power Company	2005 or market development period whichever comes first	Residential customers received a five percent decrease applied to unbundled generation service.
Cincinnati Gas & Electric Company	For five years for all residential customers	Residential customers received a five percent decrease applied to unbundled generation service.
AEP/Columbus Southern Power Company	2005 or market development period whichever comes first	Residential customers received a five percent decrease applied to unbundled generation service.
Dayton Power and Light Co.	Generation rates until Dec 31, 2003 and T&D through the ened of 2006	Residential customers received a five percent decrease applied to unbundled generation service.
Monongahela power Company	2005 for residential customers and 2003 for large industrial customers	Residential customers received a five percent decrease applied to unbundled generation service.
First Energy/Ohio Edison Company	Distribution rates through 2007	Residential customers received a five percent decrease applied to unbundled generation service.
First Energy/Illuminating Company/Cleveland Public Power	Distribution rates through 2007	Residential customers received a five percent decrease applied to unbundled generation service.

First Energy/Toledo Edison	Distribution rates through 2007	Residential customers received a five percent decrease applied to unbundled generation service.
AEP/Ohio Power Company	2005 or market development period whichever comes first	Residential customers received a five percent decrease applied to unbundled generation service.
Pennsylvania		
Allegheny Power	Rates for generation charges are capped at least until January 1, 2006	PA did not require rate reductions though several utilities offered rate reductions in first year of choice, which were to be phased out over two three year period.
Duquesne Light	Rates for generation charges are capped at least until January 1, 2006	PA did not require rate reductions though several utilities offered rate reductions in first year of choice, which were to be phased out over two three year period.
Metropolitan Edison	Rates for generation charges are capped at least until January 1, 2006	PA did not require rate reductions though several utilities offered rate reductions in first year of choice, which were to be phased out over two three year period.
Pennsylvania Electric	Rates for generation charges are capped at least until January 1, 2006	PA did not require rate reductions though several utilities offered rate reductions in first year of choice, which were to be phased out over two three year period.
PECO Energy	Rates for generation charges are capped at least until January 1, 2006	PA did not require rate reductions though several utilities offered rate reductions in first year of choice, which were to be phased out over two three year period.
Pennsylvania Power	Rates for generation charges are capped at least until January 1, 2006	PA did not require rate reductions though several utilities offered rate reductions in first year of choice, which were to be phased out over two three year period.

Pennsylvania Power and Light	Rates for generation charges are capped at least until January 1, 2006	PA did not require rate reductions though several utilities offered rate reductions in first year of choice, which were to be phased out over two three year period.
UGI Utilities	Rates for generation charges are capped at least until January 1, 2006	PA did not require rate reductions though several utilities offered rate reductions in first year of choice, which were to be phased out over two three year period.
Rhode Island		
Narragansett Electric Co.	SOS will be available through 2009	7% under the restructuring act.
Texas		
Central Power and Light	Frozen until January 1, 2007 or until 40% of residential or small commercial customers have chosen alternative suppliers	For residential customers, 8.08% decrease over September 1, 1999 rates and is subject to change up to twice per year if changes in natural gas prices and power costs occur, subject to PUCT approval.
Reliant Energy	Frozen until January 1, 2007 or until 40% of residential or small commercial customers have chosen alternative suppliers	For residential customers, 17.15% decrease over September 1, 1999 rates and is subject to change up to twice per year if changes in natural gas prices and power costs occur, subject to PUCT approval.
TXU Electric and Gas	Frozen until January 1, 2007 or until 40% of residential or small commercial customers have chosen alternative suppliers	For residential customers, 14.63% decrease over September 1, 1999 rates and is subject to change up to twice per year if changes in natural gas prices and power costs occur, subject to PUCT approval.

TXU SESCO	Frozen until January 1, 2007 or until 40% of residential or small commercial customers have chosen alternative suppliers	For residential customers, 3.60% decrease over September 1, 1999 rates and is subject to change up to twice per year if changes in natural gas prices and power costs occur, subject to PUCT approval.
Texas New Power Company	Frozen until January 1, 2007 or until 40% of residential or small commercial customers have chosen alternative suppliers	For residential customers, 18.08% decrease over September 1, 1999 rates and is subject to change up to twice per year if changes in natural gas prices and power costs occur, subject to PUCT approval.
West Texas Utilities	Frozen until January 1, 2007 or until 40% of residential or small commercial customers have chosen alternative suppliers	For residential customers, 11.01% decrease over September 1, 1999 rates and is subject to change up to twice per year if changes in natural gas prices and power costs occur, subject to PUCT approval.

Brief Biography of Kenneth Rose, Ph.D.

Dr. Rose has been working on energy and regulatory issues for more than eighteen 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 committees of the U.S. House of Representatives on regulatory matters. 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 has been quoted often in *The New York Times*, *The Washington Post*, *The Wall Street Journal*, other newspapers and in trade publications. Dr. Rose is a frequent lecturer for the School of Public Policy and Management at The Ohio State University. Prior to joining 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.