

2003 Performance Review of Electric Power Markets

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EXECUTIVE SUMMARY

Overall, the electric supply industry's struggles continue for a third year. The string of events began with the price run-ups in California and the West in 2000 and 2001, continued with Enron's disclosures and collapse in late 2001, was followed by disclosures of accounting improprieties and data misreporting, and has continued with the "credit crunch" the industry still faces. As if this was not enough to contend with, as this report was being finalized, the most widespread electrical blackout in North American history occurred. While the cause has not been determined at this time, it has already sparked a debate about possible causes and solutions and has renewed interest in federal energy legislation that was already under consideration by the U.S. Congress.

Retail Markets

The number of states that allow retail access remained at 16 states and the District of Columbia. New Mexico, Oklahoma, and West Virginia continue to postpone retail access at this time. Arkansas repealed its restructuring law this year. 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 and may also repeal its law.

Many retail markets remain relatively inactive, particularly for smaller residential customers. However, overall market activity for larger customers in some states is relatively stronger. The following summarize retail market activities in eleven jurisdictions.

Nearly all the customer switching to alternative suppliers in **Maryland** has been in Potomac Electric Power's service area. Almost 16 percent of the residential customers and over 21 percent of the nonresidential customers are enrolled with an alternative supplier in Potomac Electric's service area. There are no reported residential customers enrolled with an alternative supplier in any of the other service areas and only a very small percentage of the nonresidential customers have switched in two areas—neither exceeding two percent. Statewide, about four percent of all customers have chosen an electric supplier, less than four percent of all residential customers and about five percent of the nonresidential customers.

The **District of Columbia** is also served by Potomac Electric Power and has had similar, although lower, percentages of customer switching as in Potomac Electric's area in Maryland, at 11.4 percent residential, 16.5 percent non-residential, and 12 percent total for the District as a whole.

New Jersey conducted its second Internet auction to determine Basic Generation Service (BGS) for the state's distribution companies in February 2003. The auctions determined BGS supply for the period from August 1, 2003 through May 31,

2004. Beginning August 1, 2003, the auction-determined generation prices translated directly to the rates customers pay, when the rate caps and the discounts ended. The post-transition rates for all distribution territories in the state increased, largely due to deferred costs that the distribution companies could not recover during the transition period, but is now recovering from customers through the post-transition rates. New Jersey had some switching activity early in the state's retail access program, but customer switching across the state and across customer classes dropped to fractions of a percent and remained there as recently as the summer of this year. However, preliminary reports indicate that almost 60 percent of the largest customers in the state have switched to alternative suppliers. This is likely the result of these larger customers now having their prices based on PJM's hourly prices, unless they make provisions with a supplier of their choice, since the post-transition period began on August 1.

Pennsylvania had, at one time, the most active retail access program in the country. This changed dramatically by mid-2001, when many competitive suppliers reduced their offerings to customers or left the market entirely. As of May 2003, the entire state had only one competitive offer below the price-to-compare being made to residential customers. Residential switching continues to decline or remain flat, with all but Duquesne Light now below (in most cases, well below) ten percent of customers with an alternative supplier. In all areas, commercial customer switching is below 20 percent, however, Duquesne Light and PECO Energy have seen a recent modest increase in the percentage of customers switching. For industrial customers, all areas are well below ten percent, except Duquesne Light, which is at about 35 percent of the customers with an alternative supplier.

In **Maine**, the Commission has completed three sets of competitive bids and has a fourth underway to determine standard offer service providers and prices. While, as the Commission noted, the first two bidding experiences met with "mixed results," currently all standard offer service prices for all customers classes for the three principle T&D utilities in the state have been procured through the competitive bidding process.

There has been no switching to competitive providers by residential and small commercial customers in Bangor Hydro-Electric Co.'s (BHE) area and large customer switching has dropped to below 40 percent (after reaching well over 80 percent in 2002). Although Central Maine Power Co. (CMP) had no switching to competitive providers by residential and small commercial customers, large customer switching was nearly 80 percent in June of 2003. Maine Public Service Co.'s (MPS) current standard offer price for residential and small commercial customers has increased by 35 percent between early 2001 and when the price went into effect in March of 2003. Commercial and industrial standard offer prices have increased 37 percent and 56 percent, respectively. This may explain, at least in part, why most commercial customers (68 percent of the load) and nearly all the industrial customers (between 97 percent and 100 percent of the load since early 2002) in MPS are now served by competitive providers and are not on the standard offer price. About two-thirds of the residential and small commercial load remains on standard offer service. (Last year, the total number of

customers served by MPS was reported at 35,467 residential, 193 medium, and sixteen large customers. MPS is in northern Maine and not part of the ISO New England control area and does not have the same access to suppliers that other parts of the state have.)

The standard offer price has also increased for residential and small commercial customers since 2000 for two other distribution areas, increasing 22 percent in BHE's area and by 21 percent for customers in CMP's area.

While there has been an increase in residential customer activity since last year in **Massachusetts**, statewide, it is still less than three percent of the customers that have switched to a competitive supplier. The larger customer categories continue to show considerably more activity, however, there has been a marked decrease since the fall of 2002, especially for the large commercial and industrial customer group, which has fallen below 20 percent. Small and medium commercial and industrial customer groups also declined, both to less than ten percent of customers in each category.

For all customer groups, the most active customer switching, or "migration," in **New York** State is in the Orange and Rockland Utilities and Rochester Gas and Electric service areas. Most of this activity is concentrated among non-residential customers. This pattern of activity holds for both 2002 and 2003. With a few exceptions, most areas had modest gains in the percent of customers switching to alternatives in 2003 compared to 2002. Statewide, for all customer categories, customer migration was 5.3 percent for the state.

Illinois retail access for residential customers began on May 1, 2002. Also in May of 2002, the Illinois legislature extended the current freeze on electricity rates until 2007. At this time, there are no residential customers that have switched to an alternative supplier in the state. Also, several distribution companies are reporting no activity in their areas for all customer categories, including, AmerenCILCO Co., AmerenUE Co., Interstate Power and Light Co., and MidAmerican Energy Co. Three companies, AmerenCIPS Co., Commonwealth Edison Co., and Illinois Power Co., have had some customer switching to an alternative "Delivery Service," primarily among larger customers. However, statewide, nearly half of these Delivery Service Customers chose the Power Purchase Option, an unbundled, market-based generation option that non-residential customers subject to transition charges must be offered and is supplied by the incumbent utility.

Michigan started retail access in January 2002. While there is little activity among residential customers, there has been some activity with larger customer groups, particularly with industrial customers in Consumers Energy's territory and with commercial customers in Detroit Edison's territory.

According to the **Ohio** Commission, as of December 2002 a total of 756,411 residential customers and 848,702 customers of all classes had switched to an alternative electric supplier in Ohio. Cleveland Electric Illuminating Company had the highest percentage of all customers switching to alternatives of Ohio electric distribution companies and for all customer classes except industrial. Switching of its residential, commercial, and for total customers were all about 60 percent for each category. Ohio Edison had the highest percentage of industrial customers at over 30 percent. Toledo Edison also had relatively high percentage of customers switching, with residential, commercial, and total customer categories at about 40 percent and industrial customers at 20 percent switching to alternative suppliers. These three companies are part of FirstEnergy Corporation serving northern Ohio and had the highest regulated rates among investor-owned utilities prior to restructuring and, consequently, have higher prices-to-compare than other utilities in the state. For the other five distribution companies, no category exceeded five percent customer switching. Columbus Southern Power, Dayton Power and Light, Monongahela Power, and Ohio Power Company reported no residential customers had chosen an alternative supplier. Cincinnati Gas and Electric had less than three percent residential customer switching.

Ohio continues to have the highest residential switching in the country. However, as of December 2002, the state's aggregation program accounts for over 93 percent of residential, over 88 percent of the commercial and over 19 percent of the industrial customer switching in Ohio and over 92 percent of all customer switching in the state.

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

Due to the apparent early success of its retail markets, **Texas** has attracted a great deal of attention across the country. Since its beginning in January of 2002, the Texas retail market has been one of the more active in terms of offers to residential customers and savings opportunities. In June 2003, residential customers had between four and nine competitive providers offering between four to eleven competitive offers (this count does not include the affiliated REP standard service at the "price-to-beat" rate). All five areas had at least three offers below the price-to-beat rate, two areas had six offers, and one area had seven offers below the price-to-beat. As measured by the lowest offer, residential customers had an opportunity to save between eight percent and 24 percent off the price-to-beat rate. All service areas, except that of WTU/AEP Texas North, had three renewable, or "green," offers (all the green offers were from the same power provider).

According to the Texas Commission, commercial and industrial customers also appear to have a large variety of offers from which to choose. They report that there

were, as of September 2002, approximately 19 REPs serving commercial and industrial customers in all service territories open to competition.

Almost eight percent of all residential customers were served by a non-affiliated REP by December 2002. Both Oncor (TXU) and CenterPoint (Houston area, formerly Reliant Energy HL&P) service areas had over ten percent of residential customers being served by non-affiliated REPs in June of 2003. CPL (AEP Texas Central) had the highest percentage of secondary voltage customers (primarily smaller commercial and industrial customers, most of which are eligible for the price-to-beat) receiving power from competitive REPs. Over eleven percent of all customers in this category were with a competitive REP in December 2002.

The Commission also notes that although less than ten percent of all secondary voltage customers (68,133 customers) have switched, as reported for September 2002, the customers who have switched are among the largest customers in this customer class since about 25 percent of the MWh (about 1.8 million MWh) used by secondary voltage level customers were supplied by nonaffiliated REPs. Over 18 percent of commercial and industrial customers taking service at primary or transmission voltage levels (larger commercial and industrial customers, many of which are not-eligible for the price-to-beat) were receiving service from a non-affiliated REP in December 2002. In September, approximately 50 percent of the MWhs (1.7 million MWh) used by these customers were served by REPs not affiliated with the TDU in the customer's area.

The Commission reported that as of the end of September 2002, 400,837 individual customer premises were being served by a REP other than the incumbent affiliated REP in their service area. This was approximately 6.8 percent of all customers in areas of the state open to retail access. Of these premises, the Commission reported that 319,297 (80%) are residential customers, 71,691 (18%) are commercial and/or industrial customers that take service at the secondary voltage level (predominately smaller commercial customers eligible for the price-to-beat), and 1,322 (less than 1%) are larger commercial and industrial customers taking service at the primary and transmission voltage level and the remaining are lighting accounts.

Customers without a price-to-beat available from the affiliated REP, are essentially in the market and were encouraged to choose to purchase power from the affiliated REP or a competitive REP. As seen nationally, because these customers use large amounts of power and have a strong incentive to consider alternatives, they are usually the most active shopping group and are usually the more sought after customers by retail suppliers. In addition, the Texas Commission required affiliated REPs to give the non-price-to-beat customers advance notice of the rate they would be charged on January 1, 2002, if they did not negotiate other arrangements with the affiliated REP or switch to a competitive REP. The Commission reports that the default offers of the affiliated REP were generally either a very high fixed price offer or a passthrough of market prices, both of which may be considered risky options for most retail customers. This likely provided added incentive for these customers to shop for

the best available price, since the default offers may lead to rates higher than those in effect before retail access began. As of December 2002, approximately eight percent of non-price-to-beat customers remained on this default pricing offer, or approximately 92 percent of these customers negotiated a competitive contract with either the affiliated REP or a non-affiliated REP.

The Commission calculates the total annual savings for residential customers at approximately \$900 million in 2002 as compared to what they paid in 2001. This residential customers' savings is based on the price-to-beat rates in effect on January 1, 2002, when the savings ranged from eight percent to 18 percent compared to the rates in effect on December 31, 2001. The Commission also calculates that approximately \$225 million of this reduction is related to the statutorily mandated six percent reduction in rates and \$675 million of this reduction is attributable to reductions in fuel costs and the expiration of fuel surcharges. These two factors alone, therefore, account for all the \$900 million savings.

Residential customers had savings opportunities in all areas open to retail access that ranged between eight percent and 24 percent in June 2003. If the price-to-beat rate increases from the beginning of competition on January 1, 2002 through June 2003 are compared with the percentage savings of the lowest-priced offers to residential customers by area, no offer would have offset the increase over that period. Thus, a similar calculation of rate impact for that period would show that customers had paid more since competition began. It is likely, however, that rates would have gone up under regulation as well, due to likely fuel cost adjustments. Therefore, it is uncertain what price impact retail access has had on customers versus what would have occurred with continued regulation.

Wholesale Markets

As noted, the disturbing industry news has resulted in a continuation of 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. Standard & Poor's (S&P) noted that "familiar themes continue to dominate the bleak credit picture" for the industry. S&P cites four factors contributing to this trend: (1) accounting practices and disclosure, (2) the plethora of federal and state investigations, (3) failing confidence in future financial performance, and (4) investments outside the traditional regulated utility business, principally merchant generation facilities and related energy marketing and trading activities. As a result, the ratings trend for the investor-owned utility industry (which include electric, gas, pipeline, and water companies) is continuing on a negative slope, which began in early 2000, and actually accelerated in the first quarter of 2003, according to S&P. They noted that there were "an unprecedented 50 downgrades among holding companies and operating subsidiaries, compared with just three upgrades during the first three months of 2003." S&P also indicates that it expects the negative credit momentum to continue in 2003, although they expect the pace of negative ratings to moderate.

Three major energy producers have filed for bankruptcy protection in 2003, Xcel Energy Inc.'s NRG Energy, PG&E Corp.'s National Energy Group, and Mirant Americas Generation LLC, which includes nearly all of Mirant's wholly owned subsidiaries in the U.S. Other companies, including Dynegy Inc, have announced capital restructuring plans to allow time to improve their financial conditions. Both NRG Energy and Mirant have contract commitments with distribution companies that may significantly affect retail customer supply and prices.

The continuing credit crunch combined with the economic slowdown, has led to a cut back in investment in future generating capacity. The recent cutbacks followed a period of several years of the largest capacity expansion in the industry in over half a century. In 2002, 57,200 MW of gas-fired capacity was added with more than 50,000 MW expected again for 2003. This followed the 1999 through 2001 period when a total of 77,700 MW was added. This compares with the period 1986 through 1998 when a total of 53,900 MW of gas-fired capacity was added for the entire period. Coal capacity additions, in contrast, is expected to be only 12,800 MW between 2000 to 2009. No new plants entered construction during the first quarter of 2003.

There is a very close correlation between the spot market prices of electricity and natural gas prices. Since natural gas is the marginal fuel in most of the country and also because it is common practice to index power transactions to a natural gas price index. Power markets around the country, including PJM, New England, New York, Midwest, Texas, and Western markets, were significantly impacted in early 2003 from the spike in natural gas prices. If natural gas prices continue to remain at current levels or surge higher, this will almost certainly have a significant impact on power prices across the country.

In general, there continues to be strong evidence that significant market power is being exercised in wholesale markets that have been independently examined. The following summarize regional wholesale market events.

The principal wholesale market facilitator in the **mid-Atlantic region**, PJM Interconnection, is arguably the most developed in terms of number of market products developed and offered to participants and trading activity in these markets. Earlier analyses of overall market performance showed evidence of significant market power, particularly during peak hours of the day. In its most recent market assessment of 2002, PJM's Market Monitoring Unit (MMU) suggests that PJM's market are, in general, functioning well and without excessive market power. However, the MMU's method for assessing the markets likely understates the extent of the markup above competitive levels that suppliers can exert. The MMU did conclude that there was an exercise of market power in PJM's capacity credit market during the first quarter of 2001.

In March 2003, ISO **New England** began implementing its own version of a wholesale Standard Market Design (similar to FERC's "SMD"). This includes using Locational Marginal Pricing (LMP) for transmission congestion management, day-ahead

and real-time energy markets, and using monthly and long-term Financial Transmission Right (FTR) auctions.

According to ISO New England, approximately 29 percent of the total megawatt hours produced in the region in 2002 was from natural gas generators, this was up considerably from 13 percent in 2000. This increasing use and reliance on natural gas for power generation is causing concern in the region. ISO New England issued a White Paper that examined current and future use of natural gas for power generation and natural gas supply availability in the region. The study notes that the recent power plant building boom in the region is expected to add nearly 10,700 MW of new capacity between 1998 and 2005—all of it natural gas-fired capacity. It is expected that 41 percent of New England's total electricity production will be gas-fired in 2003 and could reach 49 percent by 2010. This problem is particularly acute in the Boston area "load pocket." The Boston subarea is expected to have 65 percent of its electricity generated by natural gas in 2003 and is forecasted to increase to 80 percent by 2010.

The western power markets has been the focus of considerable attention since the 2000 to 2001 power crisis. In its 2002 Annual Report, the **California** ISO estimates that the 2002 average markup was \$5.69 per MWh or 17 percent above costs. They note that the markup approached 35 percent in the summer months (May and July). The California ISO also began estimating a volume-weighted, twelve-month rolling average of short term markups, or the "twelve month competitiveness index." The intent is to measure the degree of market power during the market's transition to a new structure—of adequate supply and demand response. Since the ISO estimates that the index was above \$5 per MWh for each month in 2002 and peaked at nearly \$51 per MWh, they then conclude that during 2002 "some market power persists in the short-term market." They assume that the market is "workably" competitive if the index is below \$5 per MWh.

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SECTION I

Overview of Electric Restructuring Activities in the U.S.

Introduction

The electric supply industry's struggles continue for a third year. Beginning with the price run-ups in California and the West in 2000 and 2001, continuing with Enron's disclosures and collapse in late 2001, disclosures of accounting improprieties and data misreporting, and the continuing "credit crunch" in the industry. Many retail markets remain relatively inactive, particularly for smaller residential customers. However, market activity for larger customers has remained relatively stronger in some states. Also, there continues to be strong evidence that significant market power is being exercised in all markets that have been independently examined.

This section summarizes some recent important events in the industry, the impact these events are having on wholesale markets and the industry, and federal regulatory actions. This section concludes with an explanation of how market performance is measured in wholesale and retail markets. The next six sections examine different regions of the country in terms of price and other factors to provide an indication on how the wholesale markets are performing in the regions. The regions examined here are the Mid-Atlantic (PJM), New England, New York, Midwest, Texas, and the West. The state retail markets are investigated in each regional section.

Overview of State Electric Restructuring Activities

Currently, 16 states¹ and the District of Columbia allow retail access (see Figure I.1). Three states that passed an electric restructuring law, however, have opted to delay restructuring. New Mexico, Oklahoma, and West Virginia have decided to delay or postpone retail access at this time, either pending further investigation or other

¹Arizona, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Virginia.

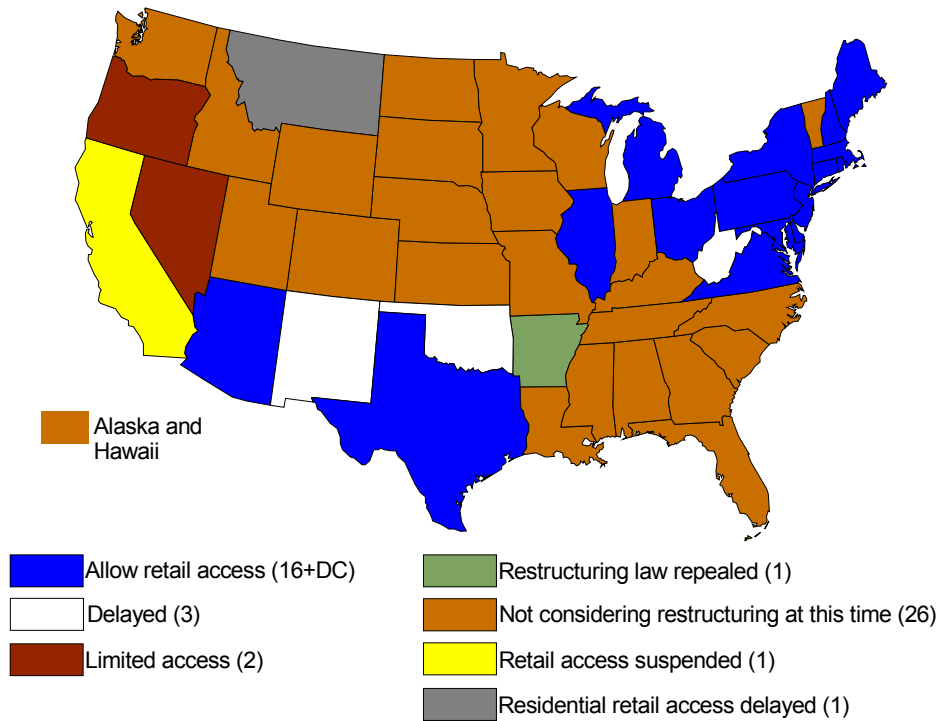


Figure I.1. Current status of state retail access.

action. West Virginia had planned a long transition period to full retail access, but has not yet proceeded to implement its restructuring law, and is not expected to anytime soon. Arkansas has repealed its restructuring law. 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 and may also repeal their law.

Continuing power industry turmoil

The electric supply industry has not had a continuation of the revelations and scandals as dramatic as those that plagued the industry beginning with Enron Corporation's collapse in late 2001 and the subsequent accounting scandals and

investigations that revealed improper accounting treatment of partnerships and subsidiaries and their market manipulation schemes. However, while the jarring headlines are gone (for now) there has been continued fallout and ramifications from these events and the investigations of these events that has kept the industry in a state of turmoil. As noted in last year's report, in addition to the Enron collapse, other firms were involved in "round trip" or "wash" sales. 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. A Federal Energy Regulatory Commission (FERC) initial staff investigation report released in August 2002² gave examples of possible 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."³

150 power traders⁴ and marketers were ordered in May of 2002 by FERC⁵ to disclose details of any "round trip," "wash," or "sell/buyback" trades they 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

²The 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.

³FERC Staff Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, August 2002, p. 58.

⁴See 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.

⁵Federal Energy Regulatory Commission, "Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-000," May 21, 2002.

trip or sell/buyback trading activities. The FERC investigation revealed that a number of companies were engaging in these transactions.

The FERC staff issued their final report in March of 2003 on their findings of price manipulation in the western markets during the crisis.⁶ FERC staff was asked by the Commission to investigate whether any entity manipulated electric or natural gas short-term prices in the West or exercised undue influence over these prices and whether this resulted in unjust and unreasonable rates in long-term power sales contracts. Staff concluded that the electricity and natural gas markets in California are “inextricably linked.” When the spot price for gas increased dramatically, it facilitated unprecedented electricity prices increases. The problems in the gas market were due, in part, to manipulated natural gas price indices compiled by trade publications. This was done by market participants through reporting false data and wash trading. Market participants, FERC staff found, provided false natural gas prices and trade volume information to industry publications that then used the data to compile price indices. This included fabricating trades, inflating trade volumes, omitting trades, and adjusting the price of trades. The primary reason for providing false information were to influence gas prices, enhance financial positions or purchase obligations, and to create the impression of a more liquid market. Market participants that sold power in California or were affiliated with a seller would benefit since the price for power was based, in part, on natural gas spot prices. Importantly for most of the U.S., FERC staff notes that natural gas is the marginal fuel in the West, as it is for most of the country (see below), thus forward gas prices affect forward power prices.

The FERC staff concluded that EnronOnline gave Enron proprietary knowledge of market conditions of which others in the market did not have access. Staff estimated that Enron’s speculative profits through EnronOnline exceeded \$500 million in 2000 and 2001. Staff also concluded that California electricity spot market prices were affected

⁶The Federal Energy Regulatory Commission, report prepared by the FERC staff, “Final Report On Price Manipulation In Western Markets, Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-000, March 2003.

by economic withholding and inflated bidding. The FERC staff investigation did not address physical withholding of generation to raise prices since FERC is addressing that issue separately. FERC staff found that one supplier, “engaged in a high-volume, rapid-fire trading strategy,” referred to as “churning,” significantly increased the price of natural gas. The inflated gas prices significantly affected index prices and California spot wholesale power prices.⁷

FERC staff states that wash trades were common on EnronOnline to create a false sense of liquidity and can distort prices. Enron also had affiliates on both sides of wash-like trades to boost volatility and raise prices. Staff analyzed an Enron experiment to test a strategy and an actual manipulation using EnronOnline. They found that even though the price change was relatively small, \$0.1/MMBtu, Enron earned more than \$3 million from the manipulation because of its large financial position.

FERC staff identified various “entities” that appear to have participated with Enron regarding price manipulation strategies, profit sharing arrangements, economic withholding, and inflated bidding. They also found evidence that the Palo Verde electric price index was manipulated and that Pacific Northwest spot power prices were also inflated.

Based on their findings, FERC staff made numerous recommendations for the Commission to consider to address the issues raised in their investigation.

Industry Credit Outlook Remains “Bleak”

As documented in last year’s report, the disturbing industry news 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. Standard & Poor’s

⁷FERC Staff Final Report on Price Manipulation in Western Markets, March 2003, p. ES-5.

(S&P) noted that “familiar themes continue to dominate the bleak credit picture”⁸ for the industry. This includes constrained access to capital due to

. . . investor skepticism over accounting practices and disclosure; the plethora of federal and state investigations; failing confidence in future financial performance that has created a liquidity crisis for some companies; and investments outside the traditional regulated utility business, principally merchant generation facilities and related energy marketing and trading activities.⁹

As a result, the ratings trend for the investor-owned utility industry (which include electric, gas, pipeline, and water companies) is continuing a negative slope, which began in early 2000, and actually accelerated in the first quarter of 2003. S&P noted that there were “an unprecedented 50 downgrades among holding companies and operating subsidiaries, compared with just three upgrades during the first three months of 2003.” S&P also indicates that it expects the negative credit momentum to continue in 2003, although they expect the pace of negative ratings to moderate.

S&P notes that some companies are decreasing or discontinuing their investments in unregulated businesses, including merchant generation, energy trading, and international investments—strategies that were intended to help them deal with competitive markets and to enhance shareholder value. The large number of downgrades, they note, has caused the average rating for the U.S. power sector as a whole to slip into the mid-‘BBB’ area (companies considered to have an “adequate capacity to meet its financial commitments”). They do not expect the industry to fall below that level and state that “companies that continue to emphasize a vertically integrated structure should hang onto an ‘A-’ average”¹⁰ (an ‘A’ rating is given to companies with a “strong capacity to meet its financial commitments”).

⁸Standard & Poor’s, “Downside Rating Trend Continues For U.S. Utilities in First Quarter,” April 24, 2003, p. 1.

⁹Standard & Poor’s, “Downside Rating Trend Continues,” p. 1.

¹⁰Standard & Poor’s, “Downside Rating Trend Continues,” p. 3.

Three major energy producers have filed for bankruptcy protection in 2003, Xcel Energy Inc.'s NRG Energy, PG&E Corp.'s National Energy Group, and Mirant Americas Generation LLC, which includes nearly all of Mirant's wholly owned subsidiaries in the U.S. Other companies, including Dynegy Inc, have announced capital restructuring plans to allow time to improve their financial conditions.

NRG Energy is under contract to supply 45 percent of Connecticut Light & Power's electricity to its 1.1 million customers. Because of its critical importance to New England's power supply, ISO New England asked FERC to ensure that the company either continues to supply the power or finds an alternative means to supply the power to the area.¹¹ In June 2003, FERC ordered NRG to continue to deliver power to CL&P until a final ruling can be made. NRG claims to be losing \$500,000 a day under a contract which is set to expire at the end of the year. A U.S. appeals court in July 2003 refused to temporarily halt the FERC order that required NRG Energy to honor its contract with CL&P until its final ruling.¹²

Mirant has 19,000 MW of U.S. generating capacity with over 10,000 MW committed to supply contracts—including about 6,000 MW from Maryland and Virginia plants for Potomac Electric Power's customers in Washington D.C. (approximately 700,000 customers).¹³ The uncommitted capacity is sold on the spot market. Mirant sells power to Potomac Electric Power at below-market prices under a four year contract arranged when Mirant bought the company's power plants in 2000.¹⁴

¹¹Utility Spotlight, "New England ISO Asks FERC Move On CL&P Power Supply from NRG," July 21, 2003.

¹²*Reuters*, "Court Rejects NRG Request to Halt FERC Order," July 16, 2003.

¹³*Reuters*, "Bankruptcy Seen Threatening Mirant Power Contracts," July 15, 2003.

¹⁴*The Washington Times*, "Bankruptcy of PEPCO Power Supplier May Increase Washington-Area Electric Bills," July 16, 2003.

Washington Gas Energy Services also has contracts with Mirant to provide power to 79,000 customers in D.C. and Maryland.¹⁵

At this point, it is uncertain how these specific contract difficulties will be resolved. It is clear, however, that they stem, at least in part, from the higher production costs caused by higher natural gas prices and resulting higher power prices. A protracted period of higher natural gas prices or occasional substantial price spikes will lead to attempts to renegotiate existing contracts and higher prices as contracts expire, regardless of the financial health of the company supplying the power. Higher prices may also lead additional companies to financial problems that have long-term (and unhedged) supply commitments. These conditions have also led some suppliers to request an increase in the fixed price of default or standard offer service in restructured states and the regulated price under fuel adjustment mechanisms in non-restructured states.

Natural Gas Capacity and Natural Gas Prices

The continuing credit crunch due to the factors just discussed, combined with the economic slowdown, has led to a cut back in investment in future generating capacity. Despite the recent cutbacks, this was after a period of several years of the largest capacity expansion in the industry in over half a century. In 2002, 57,200 MW of gas-fired capacity was added with more than 50,000 MW expected again for 2003.¹⁶ This followed the 1999 through 2001 period when a total of 77,700 MW was added. This compares with the period 1986 through 1998 when a total of 53,900 MW of gas-fired capacity was added for the entire period. Coal capacity additions, in contrast, is expected to be only 12,800 MW between 2000 to 2009.¹⁷ No new plants entered construction during the first quarter of 2003.

¹⁵*The Washington Times*, Bankruptcy of PEPCO Power Supplier, July 16, 2003.

¹⁶EPRI, "Energy Market and Generation Response," June 2003.

¹⁷EPRI, p. 2.

Figure I.2 compares the spot power prices in several U.S. mid-continent power markets and natural gas markets. This shows the close correlation between the spot market prices. As noted, natural gas is the marginal fuel in most of the country. This correlation in the spot markets for electricity is also not surprising considering that it is common practice to index power transactions to a natural gas price index. As will be seen in the regional section of this report, markets around the country (PJM, New

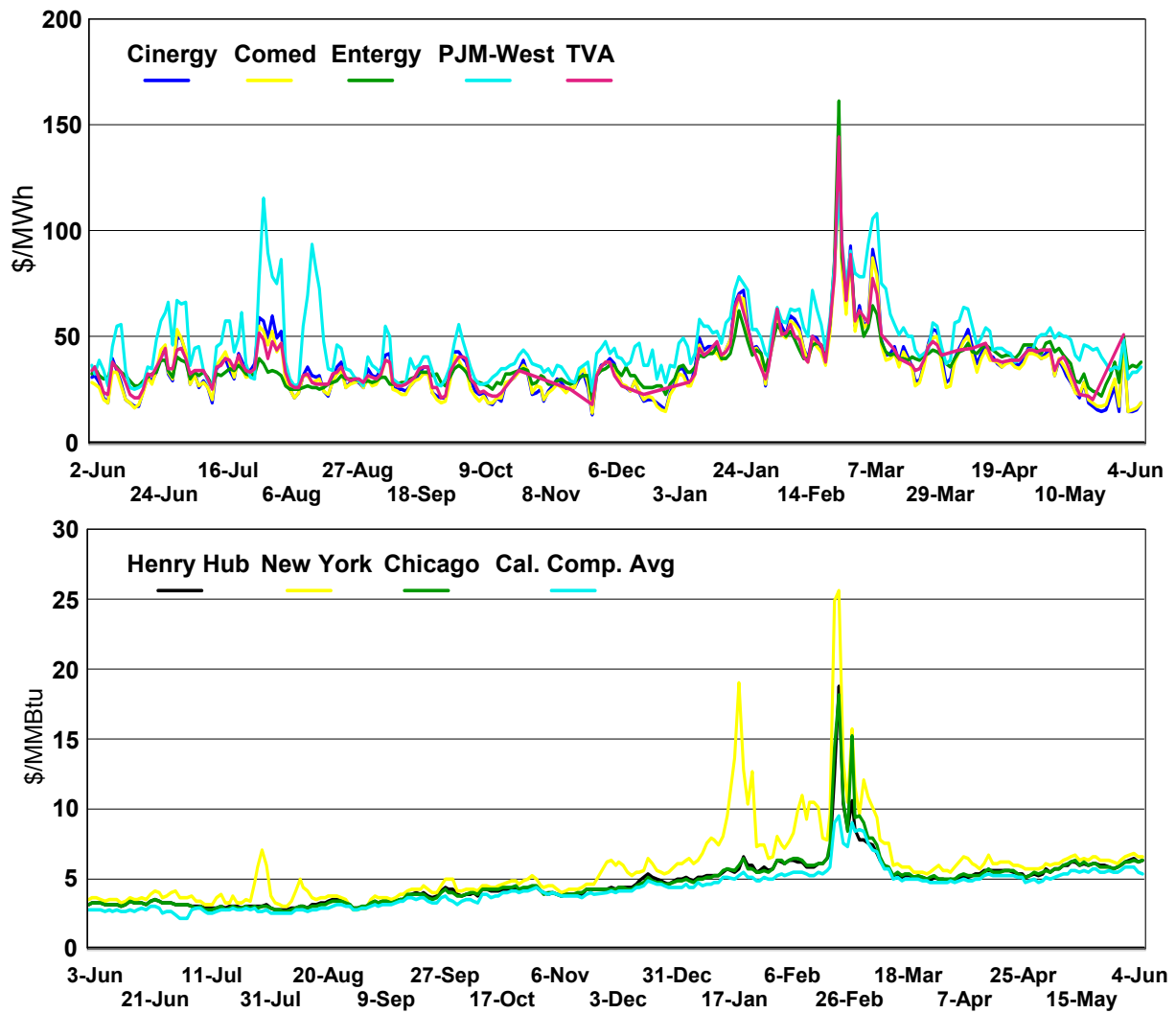


Figure I.2. Comparison of spot power prices and natural gas prices.
Sources: Data from IntercontinentalExchange, Inc. various trading hubs and U.S. Department of Energy, Energy Information Administration.

England, New York, Midwest, Texas, and Western markets), were significantly impacted in early 2003 from the spike in natural gas prices.

If natural gas prices continue to remain at current levels or surge higher, this will almost certainly have a significant impact on power prices across the country.

FERC's Standard Market Design

On July 31, 2002, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) on "Standard Market Design" (SMD). FERC stated that it believed that SMD was needed because there are inconsistent market rules across the country. These inconsistencies, they believed, have resulted in higher costs to customers, less investment in infrastructure, discrimination by transmission owners against alternative suppliers, and market manipulation. Another FERC goal was to create "seamless" wholesale power markets across the country allowing market participants to transact easily across transmission grid boundaries.

FERC allowed comments to be filed on the various parts of the NOPR, held several workshops on related issues, and also held workshops in Washington and around the country to present what the Commission wanted to accomplish and to receive feedback from others. On April 28, 2003, FERC issued a White Paper, "Wholesale Power Market Platform."¹⁸ FERC notes in the White Paper that any final rule will focus on the formation of regional transmission organizations (RTOs) and independent system operators (ISOs) and that they have "good wholesale market rules in place." The phrase "standard market design" does not appear anywhere in the White Paper. Also, the requirement that utilities create or join an Independent Transmission Provider (ITP) has been dropped. FERC anticipates that the final rule will require utilities to join an RTO or ISO, however. Importantly for states, particularly those that objected to FERC requiring a standard design for all jurisdictional regions, a final rule

¹⁸Federal Energy Regulatory Commission, White Paper, "Wholesale Power Market Platform," issued April 28, 2003. Also issued was Appendix A, "Comparison of the Proposed Wholesale Market Platform with the RTO Requirements of Order No. 2000."

would allow phased-in implementation that would be “tailored to each region” and allow modifications within each region when beneficial to customers or it can be demonstrated that the costs of any feature outweighs its benefits.

FERC states in the White Paper that it believes that the following elements need to be in place for wholesale markets to function well.

- Regional independent grid operation. A final rule will reaffirm FERC Order 2000's goal of regional independent grid operation and the required RTO characteristics for independence, scope and regional configuration, operational authority, and short-term reliability. FERC had proposed in the NOPR that all transmission owners and operators that have not yet joined a Regional Transmission Organization (RTO) be required to contract with an independent entity to operate their transmission facilities, an Independent Transmission Provider (ITP). FERC eliminated this proposed requirement that utilities create or join an ITP since RTOs and ISOs are continuing to develop and take geographic shape across the country. They note almost all utilities have already joined or committed to join an RTO or ISO. However, a Final Rule would require public utilities (excluding FERC-jurisdictional electric power cooperatives that serve only retail load) to join an RTO or ISO.
- Regional transmission planning process. A final rule will also reaffirm Order 2000's requirement that RTOs and ISOs produce technical assessments of the regional grid and support state siting authorities or multi-state entities with necessary studies. How this will be done will be decided by the region.
- Fair cost allocation for existing and new transmission. Existing grid costs (except costs associated directly with a customer) will continue to be recovered from customers through rates. Rates should permit customers to have access to the entire region at a single rate, not cumulative charges for transmission service for each service area crossed (“pancake” rates). Regional state committees may

propose a uniform regional rate for transmission service (or “postage stamp” rates) or the committee may propose different access charges that depend on where power is taken off the grid, such as based on the transmission owner’s service area (or “license plate” rates). New transmission expansion would be recovered based on a regional pricing policy—that, in FERC’s words “may be informed (sic) by the appropriate regional state committee.” Presumably, these rates would still require FERC approval.

- Market monitoring and market power mitigation. Order 2000 did have requirements for monitoring, but not market power mitigation. Each RTO or ISO would be required to have an independent market monitor. FERC believes that market power mitigation should limit the exercise of market power, but not suppress prices below what is needed to attract investment in the area. RTO or ISO policy should include limits on bidding flexibility where there is “localized” market power and prevent market manipulation strategies. FERC had proposed in the NOPR to put in place “regulatory backstops” to protect customers against the exercise of market power when structures do not support a competitive market by requiring independent monitoring and assessment of wholesale power markets in each region.
- Spot markets to meet customers’ real-time energy needs. FERC expects that most power will be bought and sold through long-term bilateral contracts between buyers and sellers. For last-minute sales or purchases for system reliability, however, FERC would require in a final rule that RTOs or ISOs use a real-time market to resolve energy imbalances. They would also be required to have a day-ahead market and a market for various ancillary services, when the market is ready. The day-ahead market must be designed to work reliably with the congestion management system. This is similar to what had been proposed in the NOPR, requiring markets for bid-based, security-constrained spot energy

markets operated on a real-time and day-ahead trading basis and for the procurement of ancillary services.

- Transparency and efficiency in congestion management. FERC had proposed in the NOPR to require all ITPs to use Locational Marginal Pricing (LMP) to manage congestion on the transmission system, as three ISOs are currently doing (PJM, New York, and New England). They are now indicating that transmission congestion should be managed with an approach developed by each region, of course, subject to FERC approval. The approach should avoid manipulation, use the grid efficiently, and promote the use of the lowest cost generation.
- For RTOs and ISOs that choose to use LMP to manage congestion, FERC will require that firm transmission rights (FTRs) be made available to customers. FTRs are designed to allow customers an opportunity to hedge against the possibility of paying a congestion charge that occurs under LMP. Holders of FTRs would be entitled to receive revenues from transmission congestion costs. FTRs would be allocated according to existing contracts and existing service arrangements. FERC would not override RTO or ISO transmission rights arrangements that have already been approved. This is similar to the Congestion Revenue Rights (CRRs) that FERC had proposed in the NOPR, except that they are reverting back to the terminology already used by some RTOs and ISOs, the requirement is contingent on the RTO or ISO choosing LMP, and auctions of FTRs will not be required, as FERC had proposed (and stated they preferred) after a transition period.
- Resource adequacy approaches. Each region with an RTO or ISO will determine how it will ensure that the region has sufficient resources to meet customer demand. The approach and the level of resource adequacy will be decided by the states in the region, including a mix of generation, transmission, energy efficiency, and demand response. Approaches include state imposed

requirements on load serving utilities or through RTO or ISO operated capacity markets. FERC had proposed in the NOPR that the RTO or other regional entity must forecast the region's future resource needs, facilitate regional determination of an adequate future level of resources, and assess the adequacy of the plans of load-serving entities to meet the regional needs. Each load-serving entity would have been required to meet its share of the future regional need through a combination of new generation and demand reduction. The resource adequacy and the regional transmission planning requirement in the NOPR raised considerable concern among many states that it would infringe on state jurisdiction. FERC did not assert jurisdictional authority in the NOPR over siting of transmission and generation facilities, however, states have been generally concerned about the potential loss of their siting jurisdiction sometime in the future and many states were concerned that a federal resource adequacy requirement would be a step toward further loss of jurisdiction. In the White Paper, FERC states "nothing in the Final Rule will change state authority" on these matters. FERC also stated that they will not include a minimum level of resource adequacy. FERC adds that an "RTO or ISO may implement a resource adequacy program only where a state (or states) asks it to do so, or where a state does not act."

The transmission pricing reforms that FERC had proposed in the NOPR to create a nondiscriminatory and standard transmission tariff for all customers was not part of the White Paper. The proposed reforms would have combined three types of current transmission service -- integrated network service and firm and non-firm point-to-point service -- into a new "Network Access Service." This would have been used to recover embedded costs of the transmission system. FERC had noted that since this would have been to standardize transmission tariffs, which will remain regulated in any case, it was not part of market design. FERC had believed that streamlining the transmission tariff would prevent discriminatory or preferential treatment that is now given to some existing transmission customers. This included the transmission portion of the bundled

rate for retail customers, and became a significantly controversial issue with states who were concerned that FERC was asserting jurisdiction in an area that had been primarily a state-jurisdictional issue.

In the White Paper, FERC indicated that *non-price* terms and conditions of the RTO or ISO tariff will apply equally to all users, including those taking service to meet their obligation to serve bundled retail customers. But FERC said it will not assert jurisdiction over the transmission *rate* component of bundled retail service.

In general, FERC has indicated that a final rule will provide more flexibility than what was originally proposed in the NOPR. While that allows states and regions to design market rules and mechanisms that are more appropriate for their area, this does place the burden on states to determine these design features. However, these wholesale market design features will have to be approved by FERC and conform to its specifications.

How wholesale market performance is measured

Among the principal reasons¹⁹ for the movement away from regulation and toward generation competition was the belief that competition would provide better incentives to control costs and that these cost savings would be passed on to consumers—resulting in lower prices for all customer classes.

The examination of the performance of the wholesale markets in this report is based on the extent to which this goal of developing a competitive market is being met. Ideally, the economic textbook case of a perfectly competitive market, there would be many suppliers vying for business. Potential new entrants would encounter few or no entry barriers and this ease of entry²⁰ would provide an additional incentive to existing suppliers to control costs and offer competitive prices to retain customers. No single

¹⁹Other reasons include increased use of innovative technologies in generation and more customer options in terms of price, fuel source, and service.

²⁰For 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.

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.²¹ The price-taking competitive firm that has no market power cannot pick its own price or influence it in any significant way. However, there are upper bound limits on price that hold even in the extreme case of market power of an unregulated monopolist that faces no meaningful threat of market entry from rival firms. Such limits reflect that the price cannot exceed what consumers are willing to pay for the product (that is, it cannot exceed demand at the quantity the monopolist wants to produce), nor can a monopolist charge a price that is sufficiently high that it creates a strong incentive for other firms to find ways around the entry barriers to the market or that encourages consumers to seek alternatives.

Of course, experience tells us that markets are routinely less than ideal or perfect. Suppliers often have at least some degree of control over the price. When this control is relatively modest, as with many markets, no corrective action is required or

²¹This can be estimated with the “Lerner Index,” which is defined as:

$$\frac{\text{Price} - \text{Marginal Cost}}{\text{Price}}$$

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.

taken. For example, if a manufacturer can raise and maintain the market price ten percent above a competitive level, and is able to do so without using any illegal anti-competitive practices (such as price fixing or in collusion with other firms),²² this relatively modest impact on price is not likely to lead to calls for corrective regulatory action. Indeed, some corrective actions may cause more harm than good by deterring new entrants or imposing additional compliance costs. Also, with low entry barriers, over time the higher price will draw the attention of potential new suppliers who will drive the price down closer to the competitive level when they enter the market. Problems arise when the price control is relatively large and has persisted, or has the potential to persist, for a long time.

How much control or price leverage a firm has is based on three factors: the overall demand characteristic of the product, the market concentration or market share of the firm, and the supply characteristics. These three factors together determine how much market power a firm can exercise. No single factor by itself would indicate a firm has considerable market power. For example, if a firm had a substantial market share, say 80 percent of the market, but entry or increased output from other firms was relatively easy and customers had suitable alternatives to the firm's product, then its actual market power potential may in fact be very low.

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

²²These and other anti-competitive practices to raise the price are illegal under Federal law. However, the unilateral exercise of market power by itself is not illegal.

many regions of the country.²³ 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,²⁴ is to either physically or economically withhold output from the market. Physical withholding is the actual withdrawal of capacity, such as claiming that a plant or plants are down for maintenance or withdrawing capacity for other reasons. Economic withholding is bidding a relatively high price with the expectation that either the plant or plants will not be selected for dispatch, or if they are selected, the owner will receive a much higher price than the marginal cost. In either case, withholding is profitable because the revenue lost from the idled capacity is more than made up for by the increased revenue gained by the operating plants that receive the higher price.

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

How retail market performance is measured

The actual prices paid by retail customers that choose a competitive supplier are not made public. Measuring an actual price trend, and the potential benefits to consumers, is therefore not always directly observable. The review of retail markets summarizes what we can observe in the markets, in terms of offers being made to residential customers, the potential savings opportunities these offers present, the

²³Pumped 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.

²⁴If 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.

number of suppliers in the area, the type of offers being made, and the percent of customers that have selected an alternative supplier, among other factors. These performance measures are, when available, included in the regional summaries in the subsequent sections.

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

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

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

As is illustrated in Figure I.3, the generation charge or price-to-compare, 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 I.3 have the same beginning regulated price, discount,²⁵ 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

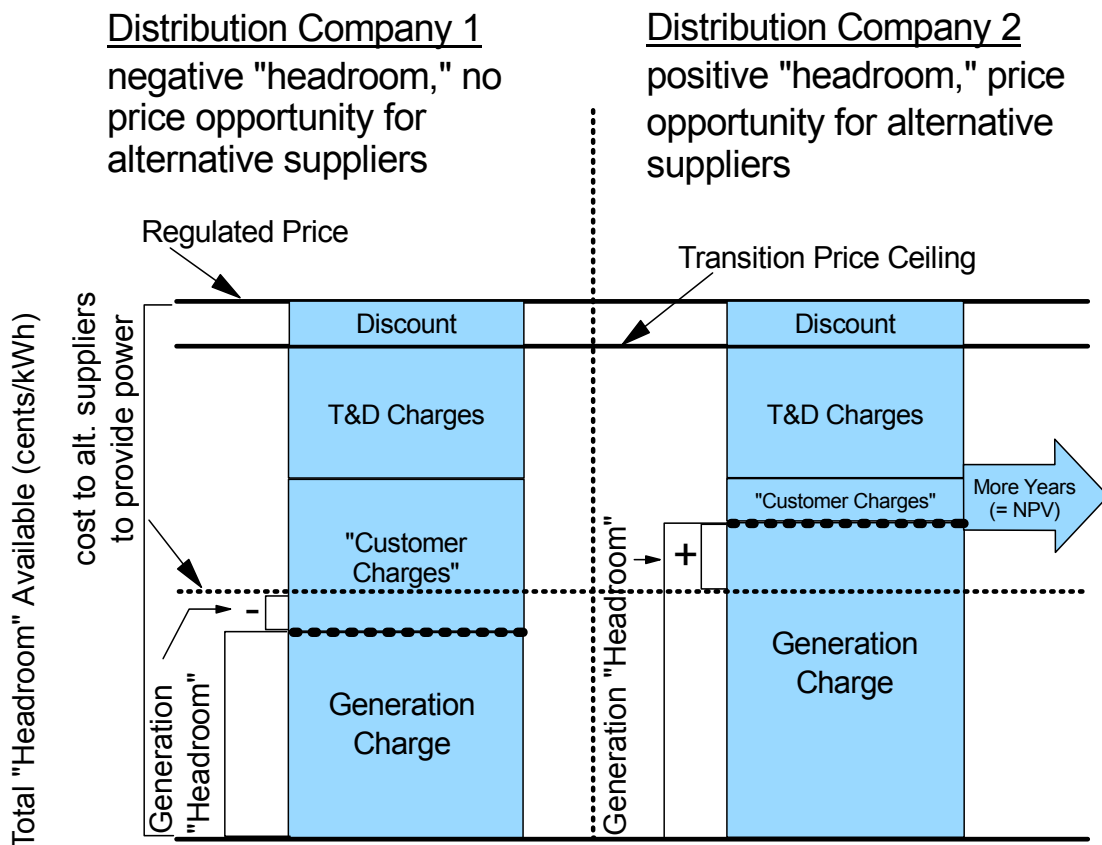


Figure I.3. Examples of two different distribution companies with different generation cost and with the same cost of procuring power for alternative suppliers.

²⁵Not all states have a discount, of course.

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 ceiling²⁶), in this case, below the cost to alternative suppliers to either procure power in the wholesale market or to generate it themselves—this cost is represented by the dotted line running across the figure.

Alternative supplier costs also include marketing, risk management, overhead, and normal return-on-investment costs, not only the direct cost of the power. In this first example, alternative suppliers will have to charge a price above what customers would pay if they stayed with the distribution company, therefore, in this case, there is “negative headroom.” In the case of distribution company two in Figure I.3, 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).²⁷ However, the headroom may be too small to cover all the 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

²⁶Another 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.

²⁷Of course, as demonstrated by the existence of “green” suppliers, who offer power generated to some degree by renewable or “clean” energy resources, price is not the only consideration customers use to select a supplier. Other factors include reliability, fuel source, and contract terms. While a small subset of customers are willing to pay a premium for these other factors, price is still the dominant consideration for most customers.

distribution company 1).²⁸ Assuming alternative suppliers do not want to operate at a loss for too long, they will not enter or will leave a market under these conditions. In general, of the relative factors of retail price for generation and the wholesale cost of power, the wholesale cost is more volatile. Price fluctuations and volatility, or the future threat of it, can increase the cost to alternative suppliers and be a determining factor in a decision to participate or continue to participate in a market.

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

²⁸An extreme example of negative headroom is California, which led one distribution company (PG&E) to the filing for bankruptcy protection and severe financial difficulties for another. Distribution companies in other states, for example, Massachusetts and Pennsylvania (GPU), have received upward adjustments to the standard offer price to recover the increased cost of obtaining power in the wholesale market (made necessary because the distribution companies sold their own generating capacity). In the Pennsylvania/GPU case, a settlement reached in June of 2001 allows GPU to defer for ratemaking and accounting purposes the difference between what it can charge customers for generation under the rate cap and its actual cost to supply electricity. The deferral provision of the settlement allows GPU to retain unrecovered generation costs on its books until 2010. Overall customer rates will not increase (the rate cap was extended through 2007), but the “shopping credit” or price-to-compare will increase. The settlement ends the Competitive Transition Charge (CTC) in 2015. GPU stated that it lost \$47 million on electricity supply in Pennsylvania in 2000 and estimated it would lose an additional \$250 million in 2001 without rate relief.

SECTION II

Electric Restructuring Activity in the Mid-Atlantic Region

Wholesale Market and PJM Interconnection¹

PJM Interconnection, L.L.C.'s (or PJM) origins date back to 1927 when three companies formed the first power pool, the "Pennsylvania-New Jersey Interconnection." In 1956, three more companies were added and the pool became the "Pennsylvania-New Jersey-Maryland" Interconnection (the beginning as "PJM"). In 1981 PJM added two members, bringing membership to eight companies. Today PJM claims to operate the largest wholesale electric market in the world and coordinates the movement of electricity throughout the mid-Atlantic states. Figure II.1, is a map of PJM's and PJM West's control areas. PJM's control area currently has 25.1 million people in it, 614 generation sources of various fuel types, more than 76,000 megawatts of generating capacity, 329 million megawatt-hours of annual delivered energy, 20,000 miles of transmission lines, and more than 245 participants in its markets.

Because of its history as a coordinated power pool, PJM was able to quickly develop into an Independent System Operator (ISO) and perform the market coordination it does today. For this reason PJM is currently the most developed wholesale market in the U.S. and has considerable information on its operations. In addition to operating and monitoring its electricity markets, PJM also plans transmission and generation expansion for the area. There are currently plans under consideration to expand PJM as far west as Iowa and south to include practically all of the state of Virginia.

PJM Markets

PJM operates a number of different power markets, including: day-ahead and real-time energy markets; daily, monthly, and multi-monthly capacity credit markets;

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

several ancillary service markets; and monthly FTR auction markets. PJM introduced nodal energy pricing with market-clearing prices on April 1, 1998 and nodal, market-clearing prices based on competitive offers on April 1, 1999 (LMP). PJM implemented a competitive auction-based FTR market on May 1, 1999. Daily capacity markets were introduced on January 1, 1999 and were broadened to include monthly and multi-monthly markets in mid-1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000.

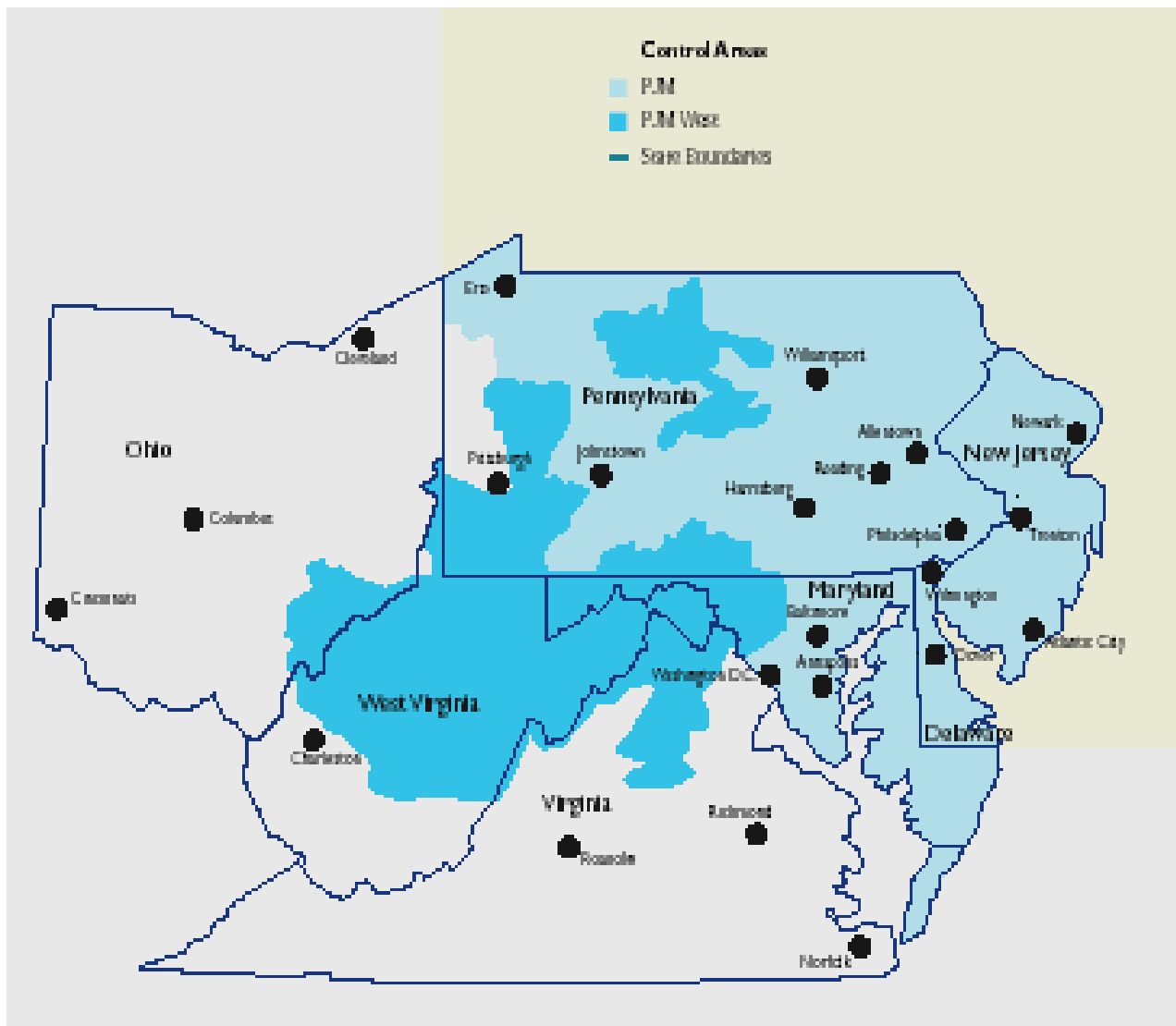


Figure II.1. The PJM and PJM West control areas.
Source: PJM.

Energy Markets

The day-ahead energy market is a forward market in which day-ahead locational marginal prices (LMPs) are calculated for each hour of the next operating day based on generation offers, demand bids, and bilateral transactions submitted in the day-ahead market. The real-time energy market is based on current day operations in which real-time LMPs are calculated at five-minute intervals based on the actual system operating conditions. Figure II.2 plots PJM's monthly weighted average LMPs for April 2002 to May 2003. As discussed in Section I, the impact of higher natural gas prices in early 2003 can be seen in the February and March weighted average prices.

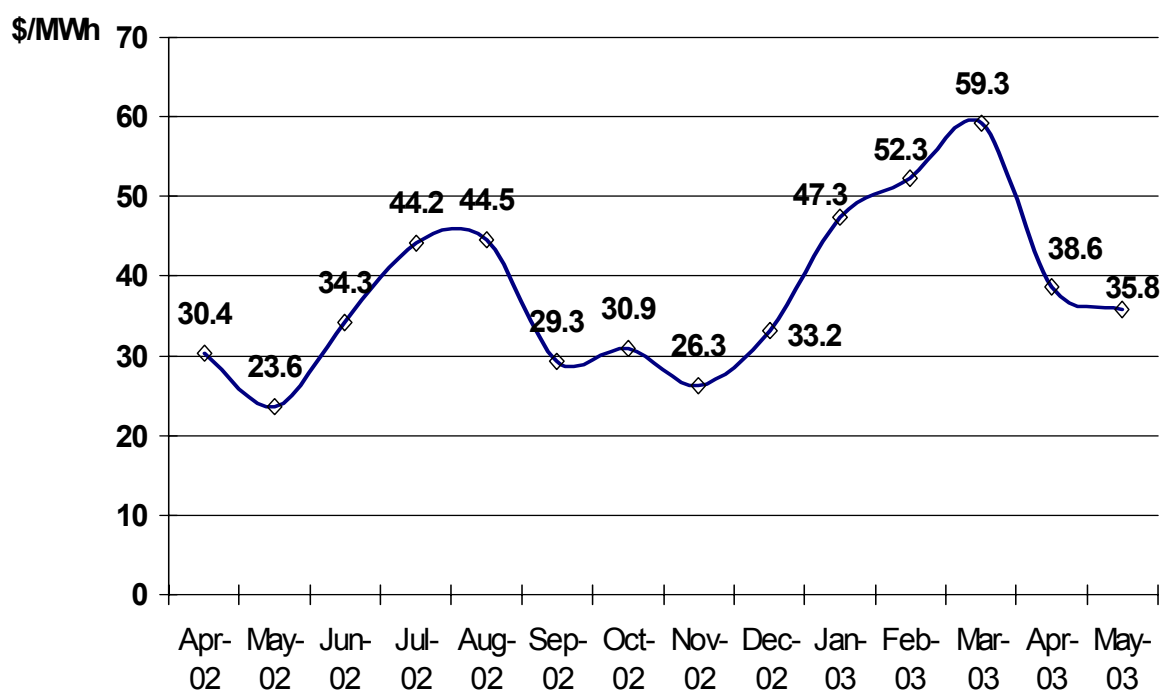


Figure II.2. PJM monthly weighted average LMPs, April 2002 to May 2003.
Source: PJM.

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

Capacity Markets

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

Ancillary Services: Regulation Market

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

Ancillary Services: Spinning Reserve

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

Fixed Transmission Rights

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

transmission system between the receipt and delivery points specified in the FTR, the holder of the FTR is awarded a share of the Transmission Congestion Charges collected from the market participants.

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

FTRs are financial entitlements that enable holders to receive revenues (or charges) based on transmission congestion measured as the hourly energy locational marginal price differences in the day-ahead market across a specific path. An FTR does not represent a right to physical delivery of power. FTRs can protect transmission service customers, whose day-ahead energy deliveries are consistent with their FTRs, from uncertain costs caused by transmission congestion in the day-ahead market. Transmission customers are hedged against real-time congestion by matching real-time energy schedules with day-ahead energy schedules. FTRs can also provide a hedge for market participants against the basic risk associated with delivering energy from one

bus or aggregate to another. An FTR holder does not need to deliver energy in order to receive congestion credits. FTRs can be purchased with no intent to deliver power on a path.

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

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

While this situation may be occasional, there are transmission system constraints, such as with a number of "load pockets" scattered throughout PJM and in other parts of the country that could result in significant congestion charges. It is also not clear just how common and pervasive these types of constrained conditions are throughout the country. The western U.S., for example, has many isolated load pockets, including some large urban areas that are separated by long distances. Supporters of the LMP/FTR concept have argued that the process sends the correct economic incentive to build generation in the transmission-constrained area or to find ways to relieve the congestion with additional transmission capacity. However, critics have argued that adding additional transmission lines may require the siting of new

transmission rights-of-ways, which is always difficult and costly. Even additional capacity on existing rights-of-ways are often difficult and costly as well. Moreover, as critics note, it is already known that additional generation is likely needed in the area and that additional transmission capacity would ameliorate the congestion problem, so the additional cost from the LMP “incentive” is superfluous and will only result in higher costs for customers.

Market Performance

An overview of how wholesale market performance is analyzed and the issues involved are presented in Section I. Specific analyses of PJM’s markets are presented in this subsection.

In an analysis summarized in previous years’ reports, it was noted that Erin T. Mansur² 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.³ 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). Mansur’s study remains the most recent independent analysis of PJM’s markets.

²Erin T. Mansur, "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market," University of California Energy Institute (PWP-083), April 2001.

³Her 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?”

In PJM MMU's reports of the year 2001⁴ and 2002,⁵ the markups or Lerner indices are also much lower than Mansur's or as reported in other markets. The average markup for both 2001 and 2002 was calculated to be 0.02 (2 percent), with a maximum monthly markup of 0.05 (5 percent) for January 2001 and 0.04 (4 percent) for July 2002. The minimum monthly market was less than 0.01 (less than 1 percent) for November 2001 and again for several months in 2002. The MMU also calculated monthly markups assuming that there is a 10 percent markup over cost, since generators in PJM are allowed to provide cost-based offers with up to a 10 percent markup over cost. An adjusted markup calculation removes the assumed potential 10 percent increase over cost and results in the average markup for 2001 and 2002 to increase to 0.11 (11 percent) with a monthly maximum of 0.13 (13 percent) in January 2001 and again in July 2002 and a minimum of 0.09 (9 percent) for October 2001 and 0.10 (10 percent) for several months in 2002.

As noted last year, 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. If this is the case, then this will likely understate the markups (or Lerner) index.⁶ 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

⁴Market Monitoring Unit, PJM Interconnection, L.L.C, "PJM Interconnection State of the Market Report 2001," June 2002.

⁵Market Monitoring Unit, PJM Interconnection, L.L.C, "2002 State of the Market Report," March 5, 2003.

⁶Recall that the markup or Lerner index is calculated as: $(\text{Price} - \text{Marginal Cost})/\text{Price}$. If the marginal cost is overestimated, the markup will be understated.

incremental cost⁷ of the lowest cost unit that is not needed to serve demand. This difference in how the marginal cost is estimated likely accounts for a considerable amount of the widely different markup estimates of Mansur's from the PJM MMU's.

In a different analysis, the MMU concluded that there was an exercise of market power in PJM's capacity credit markets during the first quarter of 2001.⁸ As explained above, Load Serving Entities (LSEs) 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 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 II.3. 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 also be seen in Figure II.3.

⁷Since actual marginal cost is unknown, "incremental cost" is used to refer to the estimated marginal cost based on the resource costs of production.

⁸PJM Interconnection, L.L.C., Market Monitoring Unit, "Report to the Pennsylvania Public Utility Commission, Capacity Market Questions," November 2001.

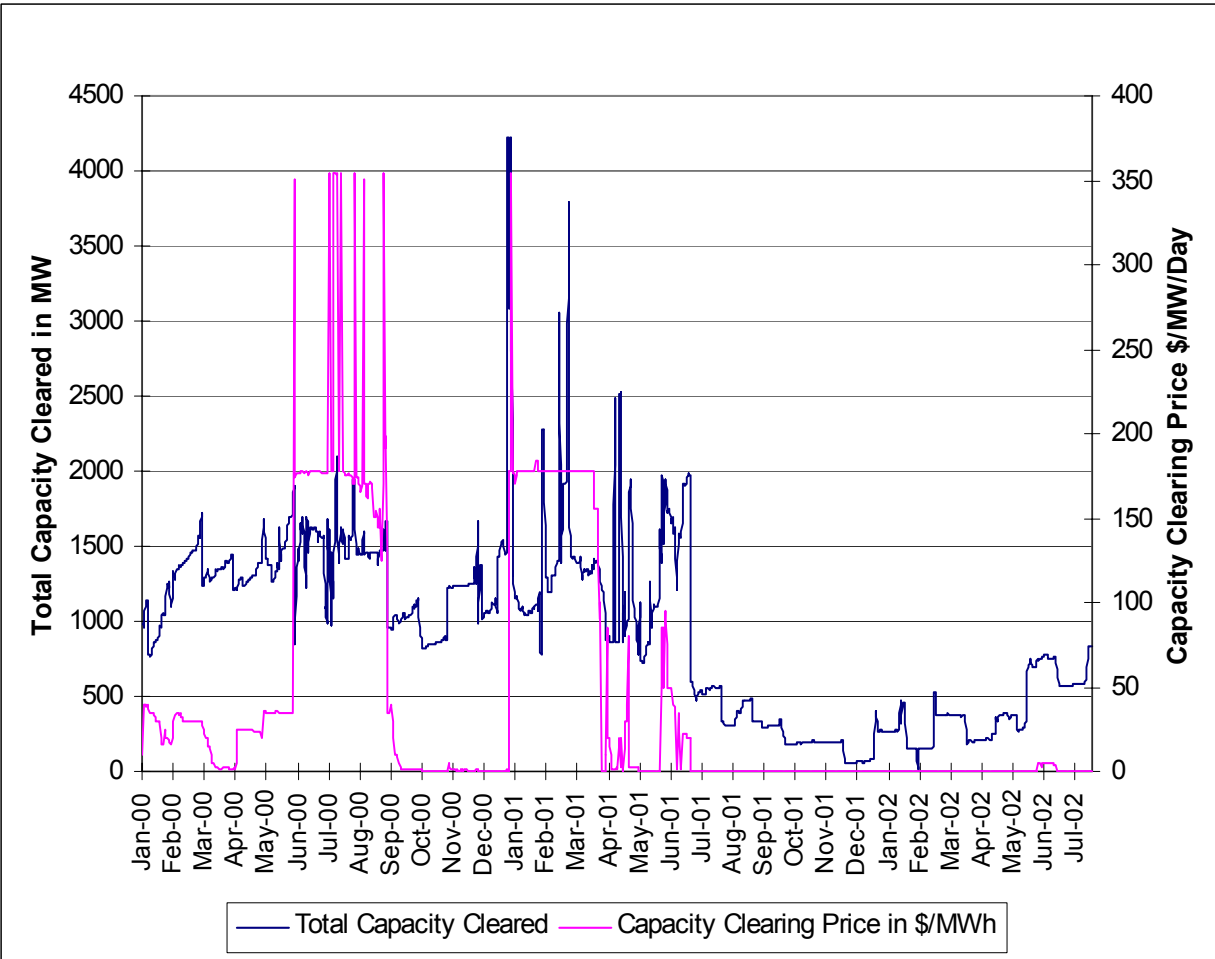


Figure II.3. PJM daily capacity market prices and MWs cleared.
 Source: PJM data.

In a letter to financial analysts in December 2001, PPL Corporation's executive vice president and chief financial officer identified PPL EnergyPlus, L.L.C. (an energy marketing affiliate of PPL Corp.) as "Entity 1" in the PJM MMU report.

In an "Investigation Report," the Pennsylvania Public Utility Commission⁹ 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.¹⁰

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.

After a year long review, the Pennsylvania Attorney General concluded (in a press release) that:

. . . the price increase was actually caused by the PJM's (sic) increase in the amount of capacity each firm selling electricity was required to hold. While PPL benefitted by being a holder with extra capacity to sell, it did not cause the conditions that led to the price increase."

'We agree with the [Pennsylvania] PUC that PPL had market power in the first quarter of 2001,' [Attorney General] Fisher said. 'However, our extensive investigation determined that PPL did not violate antitrust laws in acquiring that market power.'¹¹

The Pennsylvania Attorney General closed its antitrust investigation with this finding.

The capacity credit market's problems combined with the energy market prices in early 2001 was clearly a significant factor that caused the drop-off in retail market

⁹Pennsylvania 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.

¹⁰Pennsylvania Public Utility Commission, "Investigation Report," pp. 3 - 4.

¹¹Pennsylvania Attorney General, Press Release, "AG Fisher closes antitrust case involving PPL; Determines that electric company did not violate laws," June 18, 2003.

activity in Pennsylvania and other PJM states. The highest “shopping credit” or price-to-compare for generation service in Pennsylvania at that time was in PECO Energy’s territory, at 5.67 cents/kWh.¹² When energy prices are over \$50/MWh, as it averaged during December of 2000 and again in August of 2001, adding \$10/MWh for capacity¹³ 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 kilowatt-hour 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.

Figure II.4 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 index of 0.2 by .70 capacity ratio and reach a higher peak than California’s regression line at just over .80 capacity ratio. The overall pattern is nearly identical for PJM and New England and all three markets have a similar pattern of moderate to low Lerner indices when residual demand is relatively low and Lerner indices rising quickly to very high levels as residual demand increases. While this data is now somewhat dated, it does provide a representation of how the level of the markup is, as explained in Section I, largely a function of the supply/demand constraints.

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

¹³The 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.”

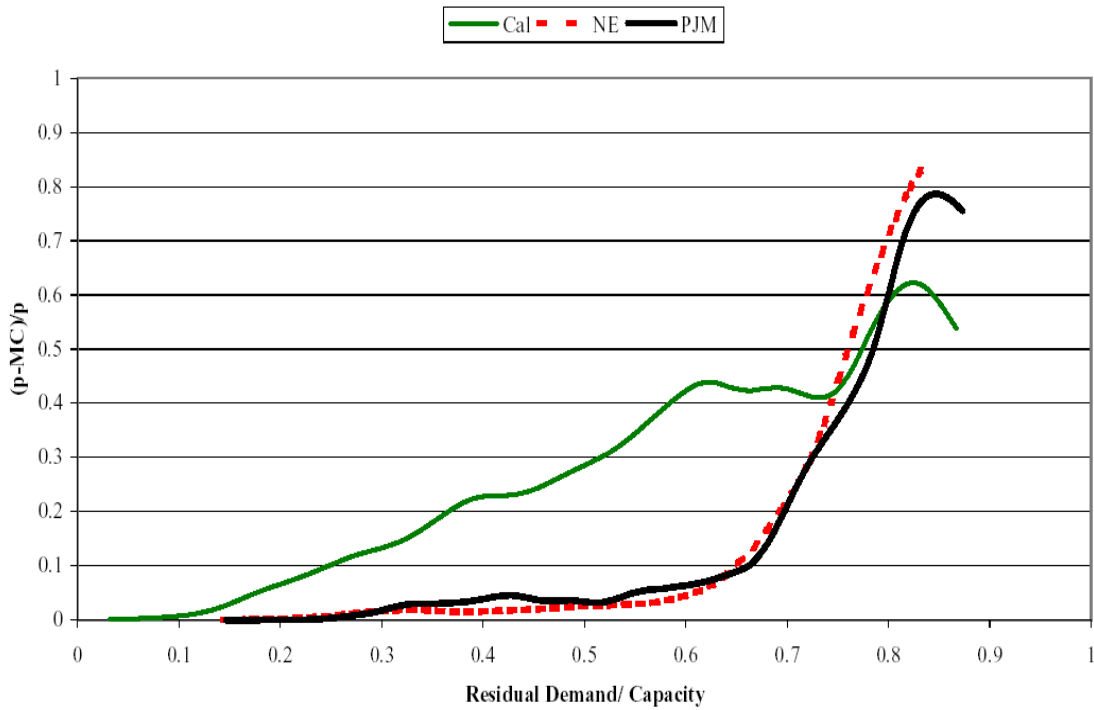


Figure II.4. Comparison of California, New England, and PJM relationship between demand level and Lerner index.
 Source: Bushnell and Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," May 2002.

Retail Markets

Maryland

As summarized in Table II.1 below, nearly all the customer switching to alternative suppliers in Maryland has been in Potomac Electric Power's service area. Almost 16 percent of the residential customers and over 21 percent of the non-residential customers are enrolled with an alternative supplier in Potomac Electric's service area. There are no reported residential customers enrolled with an alternative supplier in any of the other service areas and only a very small percentage of the non-residential customers had switched in two areas—neither exceeding two percent. Statewide, about four percent of all customers have chosen an electric supplier, less than four percent of all residential customers and about five percent of the non-residential customers.

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

Utility	Residential	Non-Residential	Total
Allegheny Power	0	0	0
Baltimore Gas & Electric	0	0.5%	0.1%
Conectiv Power Delivery	0	1.6%	0.2%
Potomac Electric Power	15.7%	21.4%	16.2%
Total	3.8%	5.1%	3.9%

Source: Maryland Public Service Commission, for month ending April 25, 2003.

Two areas had offers to residential customers, as summarized in Table II.2. As might be expected, most of the offers to residential customers were in the Potomac Electric area. Potomac Electric's area also had the only offer that was below the price-to-compare for the state. Four areas had no offers.

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

Utility	Number of Competitive Suppliers	Total Number of Offers from Competitive Suppliers	Number of Offers Below the Price-to-Compare
Allegheny Power	0	0	0
Baltimore Gas & Electric	1	2	0
Choptank Electric Cooperative	0	0	0
Conectiv Power Delivery	0	0	0
Potomac Electric Power	2	3	1
Southern Maryland Electric Cooperative	0	0	0
Total for State	2	5	1

Source: Maryland Attorney General, May 14, 2003.

District of Columbia

The District of Columbia is also served by Potomac Electric Power and, as Table II.3 shows, has had similar, although lower, percentages of customer switching as in Potomac Electric's area in Maryland.

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

	Residential	Non-Residential	Total
April 2003	11.4%	16.5%	12.0%

Source: District of Columbia Public Service Commission, May 2003.

New Jersey

As reported in the two previous years' reports, New Jersey had some activity early in the state's retail access program. One utility, Conectiv, reached almost 12 percent of the non-residential customers and almost six percent of residential customers being served by alternative suppliers, as reported for November 2000. Two other utilities had about six percent of the non-residential customers that had chosen an alternative, also reported for November 2000. About one year later, by October 2001, all customer switching by non-residential and residential customers had dropped to less than one percent for all companies. As Table II.4 shows, customer switching across the state and across companies reportedly remain at fractions of a percent from January through July of 2003. Current indications are, for reason explained below, the largest customers in New Jersey are now choosing suppliers at relatively higher rates.

Table II.4. Percent of customers served by competitive suppliers.

Distribution Company	Residential		Non-Residential		Total	
	Jan 2003	July 2003	Jan 2003	July 2003	Jan 2003	July 2003
Conectiv	0.091	0.081	0.756	0.307	0.171	0.108
JCP&L	0.037	0.037	0.048	0.044	0.038	0.038
PSE&G	0.062	0.055	0.044	0.039	0.059	0.052
Rockland	0.000	0.000	0.000	0.000	0.000	0.000
Statewide Total	0.058	0.052	0.137	0.076	0.068	0.055

Source: New Jersey Board of Public Utilities, January 15, 2003 and July 29, 2003.

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 New Jersey's 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 was 4.87 cents per kWh compared to the customers' previous rate of 5.06 cents per kWh. Conectiv's price was set at 5.12 cents per kWh compared to its previous customer rate of 5.17 cents charged from January to August of 2001.¹⁴ The prices for Rockland and PSE&G were 5.82 cents per kWh and 5.11 cents per kWh, respectively.

The price results of the 2003 "Fixed Price" auction, held in February 2003, for BGS for small to medium-sized customers are shown in Table II.5. Another separate auction determined hourly energy prices for approximately 1,750 larger customers, with prices based on PJM's hourly prices. Again, Internet auctions determined BGS for all the state's distribution companies. This was to provide BGS supply for the period from August 1, 2003 through May 31, 2004. The fixed price auction (for the smaller customers) concluded after 14 rounds of bidding and had 15 winning bidders sharing approximately 15,500 MW of load. The auction for hourly service (for larger customers) had 15 rounds with eight bidders for the 2,500 MW of available load. New Jersey is currently the only state in the country using such an Internet-based auction procedure. (Maine, as summarized in Section III, uses a competitive bidding process for its "standard offer" generation service.) Except for Rockland, all prices were somewhat higher than those determined in the previous year's auction.

¹⁴ 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.

Table II.5. Price results from the 2003 “Fixed Price” auction for small to medium-sized customers (cents/kWh).

Distribution Company	10 Month	34 Month
Conectiv	5.260	5.529
JCP&L	5.042	5.587
PSE&G	5.386	5.560
Rockland	5.557	5.601

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

Beginning August 1, 2003, the auction-determined generation prices translated directly to the rates customers pay. This was when the rate caps and the discounts ended and the post-transition period began. The New Jersey Board of Public Utilities determined the post-transition, non-generation portion of rates for customers in July 2003. Beginning August 1, 2003, excluding the BGS portion, all Conectiv customer classes had an average rate increase of approximately 4.7 percent. The estimated average BGS increase for all fixed-price customer classes is about 3.4 percent, resulting in a total rate increase of 8.1 percent. The average residential customer had an increase of approximately 6 percent on their monthly bill (the average residential bill would increase from \$85.77 per month to \$90.93 per month). This includes deferred balances accrued by Conectiv during the transition period when the rate cap was in effect and the company could not recover all of its costs incurred to supply its customers (which New Jersey’s restructuring law allows recovery after the four-year transition period). The Board also determined that Rockland’s (a company that also had deferred balances) rates for the average residential customer would increase by 15.4 percent. This includes the estimated 11.3 percent increase in BGS charges and resulted in a monthly bill increase from \$85.21 per month for the average residential customer to \$98.36 per month. The Board also authorized PSE&G (again with deferred energy costs) an increase of approximately 15 percent for the residential customer class. The Board modified the rate design in a proposed settlement to assure that the majority of

residential customers receive no more than a 15 percent increase on an overall annual basis, including BGS prices. For Jersey Central Power & Light, the Board approved an average annual increase in rates of approximately 3.5 percent for the typical residential customer. All these rate increases became effective August 1, 2003.

As noted, for approximately 1,750 larger customers, prices are based on PJM's hourly prices, unless these customers make provisions with a supplier of their choice. Preliminary indications are that for 1,766 of these larger customers state-wide, over 1,000 customer accounts have switched, or 57 percent of the customers. By company, the preliminary numbers are approximately 61 percent, 60 percent, 56 percent, and 43 percent for Conectiv, JCP&L, PSE&G, and Rockland, respectively. Obviously a dramatic change from the numbers reported in Table II.4 and most likely the result of the change to PJM hourly prices if a supplier is not selected by these customers.

Pennsylvania

Pennsylvania had, at one time, the most active retail access program in the country. In early 2000, PECO Energy alone, then the most active service area in the state (and the country), had 29 offers being made to residential customers—about 20 of which were below the price-to-compare. Every service area in the state had at least two offers to residential customers that were below the price-to-compare. This changed dramatically by mid-2001, when many competitive suppliers reduced their offerings to customers or left the market entirely (see the above discussion on the effect the capacity credit market had on retail suppliers). Table II.6 shows, as of May 2003, the entire state had only one offer below the price-to-compare, in Duquesne Light's service territory. Last year, in May 2002, the state had three such offers, all in PECO Energy's service territory. Overall, the state remains about as it was last year in terms of total number of residential offers, at 29 this year compared with 33 total offers last year. This year (as of May 2003), as with last year's survey (May 2002), each service territory had at least three residential offers.

Table II.6. Competitive offer summary for Pennsylvania.*

Utility	Number of Competitive Suppliers	Total Number of Offers from Competitive Suppliers	Number of Offers Below the Price-to-Compare
Allegheny Power	2	3	0
Duquesne Light	3	4	1
Met Ed	2	3	0
PECO Energy**	6	7	0
Penelec	2	3	0
Penn Power	2	3	0
PPL Utilities	2	3	0
UGI	2	3	0
Total for State	7	29	1

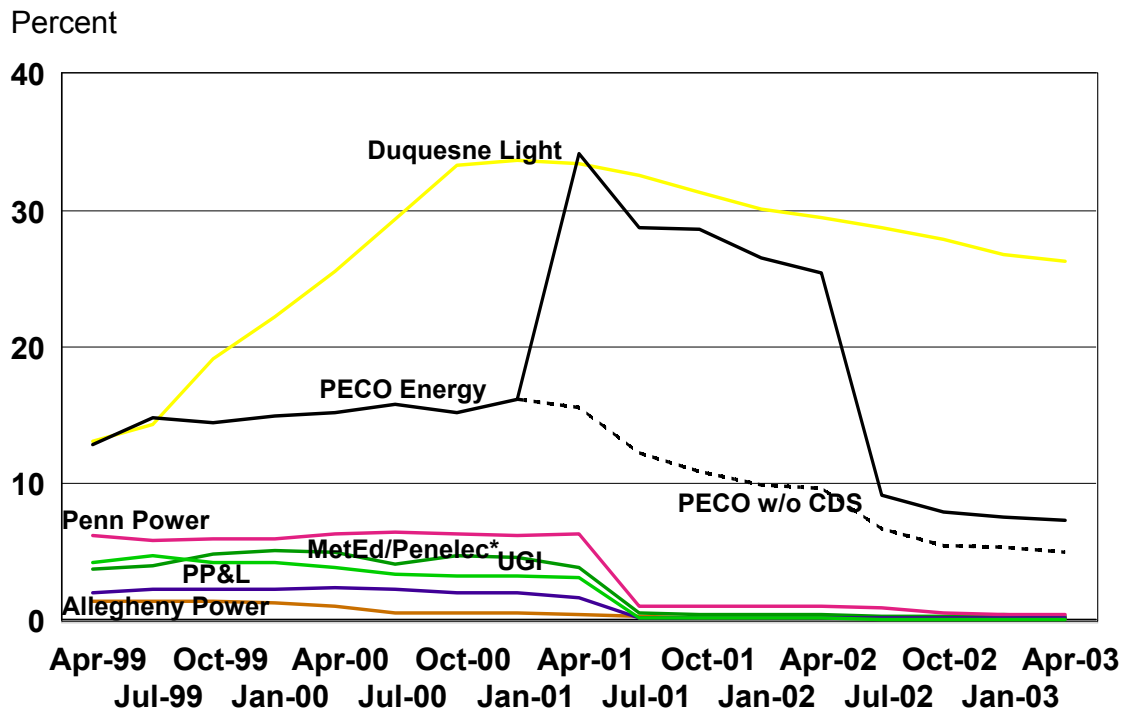
*For Regular Residential Service.

**Does not include the “Competitive Discount Service” (CDS), which is priced at 0.12 cents/kWh less than PECO Energy’s Price-to-compare, or at a two percent discount. This is only available to preselected customers, not available to new customers. Source: Pennsylvania Office of Consumer Advocate, May 2003.

Figures II.5, II.6, and II.7 plot the customer switching activity for Pennsylvania back to the first quarter of retail access in the state for residential, commercial, and industrial customers, respectively. The decrease that occurred in 2001 in retail market activity can be seen in all three customer groups. Residential switching continues to decline or remain flat, with all but Duquesne Light now below (in most cases, well below) ten percent of customers with an alternative supplier. With commercial customers, all areas are below 20 percent, however, Duquesne Light and PECO Energy have seen a recent modest increase in the percentage of customers switching. For industrial customers, all areas are well below ten percent, except Duquesne Light, which is at about 35 percent of the customers with an alternative supplier.

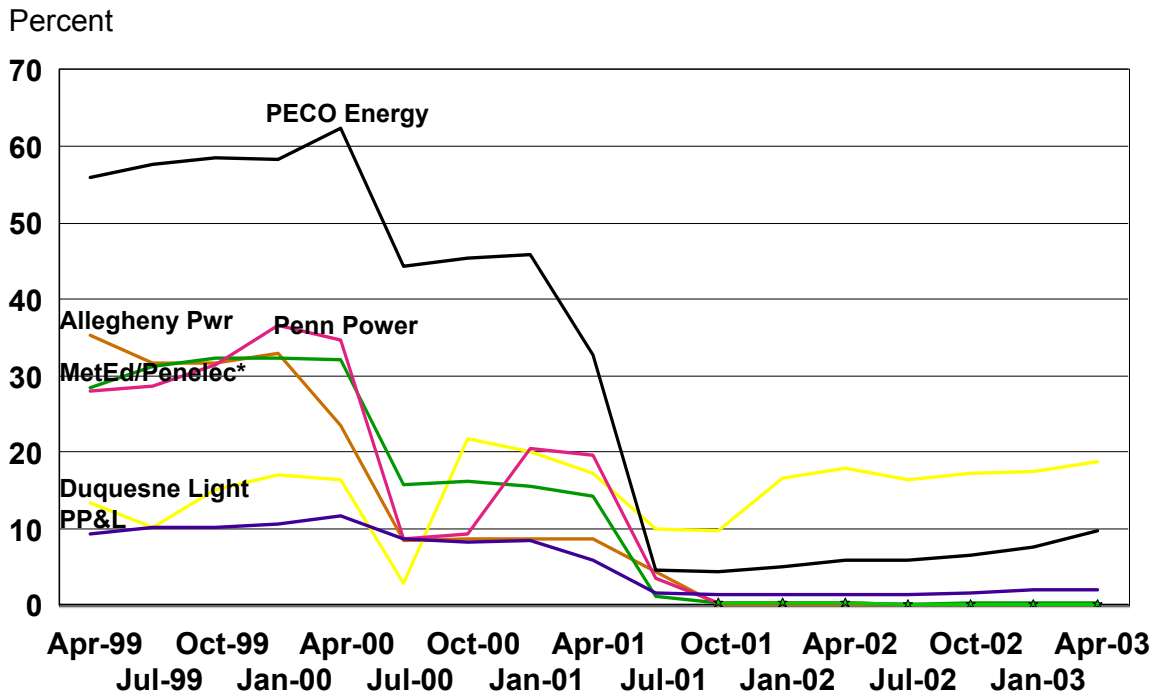
Figure II.8 shows the decline in customer switching in the state in terms of total load. The peak was reached in April of 2000, at 8,320 MWs, fell to 5,509 MWs in July

2000, then fell again to 2,039 MWs in July 2001. Since then, total load served by an alternative supplier has climbed back to 2,621 MWs in April 2003.



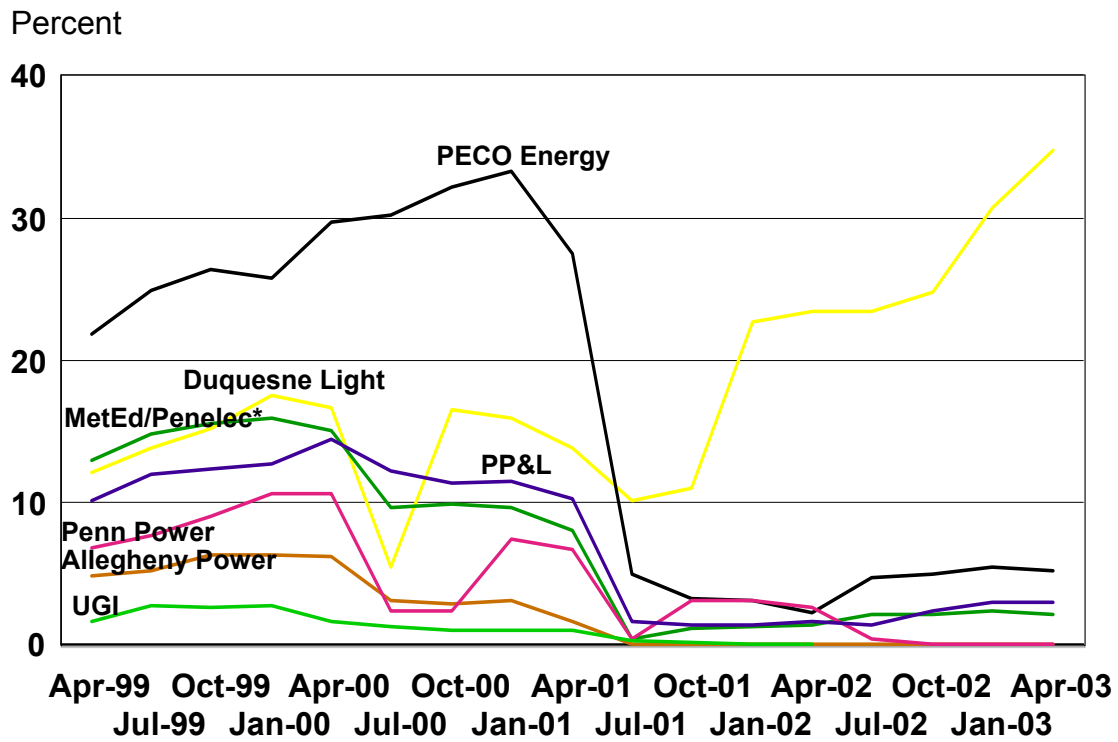
*MetEd and Penelec were formerly part of GPU.
 Data Source: Pennsylvania Office of Consumer Advocate

Figure II.5. Residential customer switching in Pennsylvania.



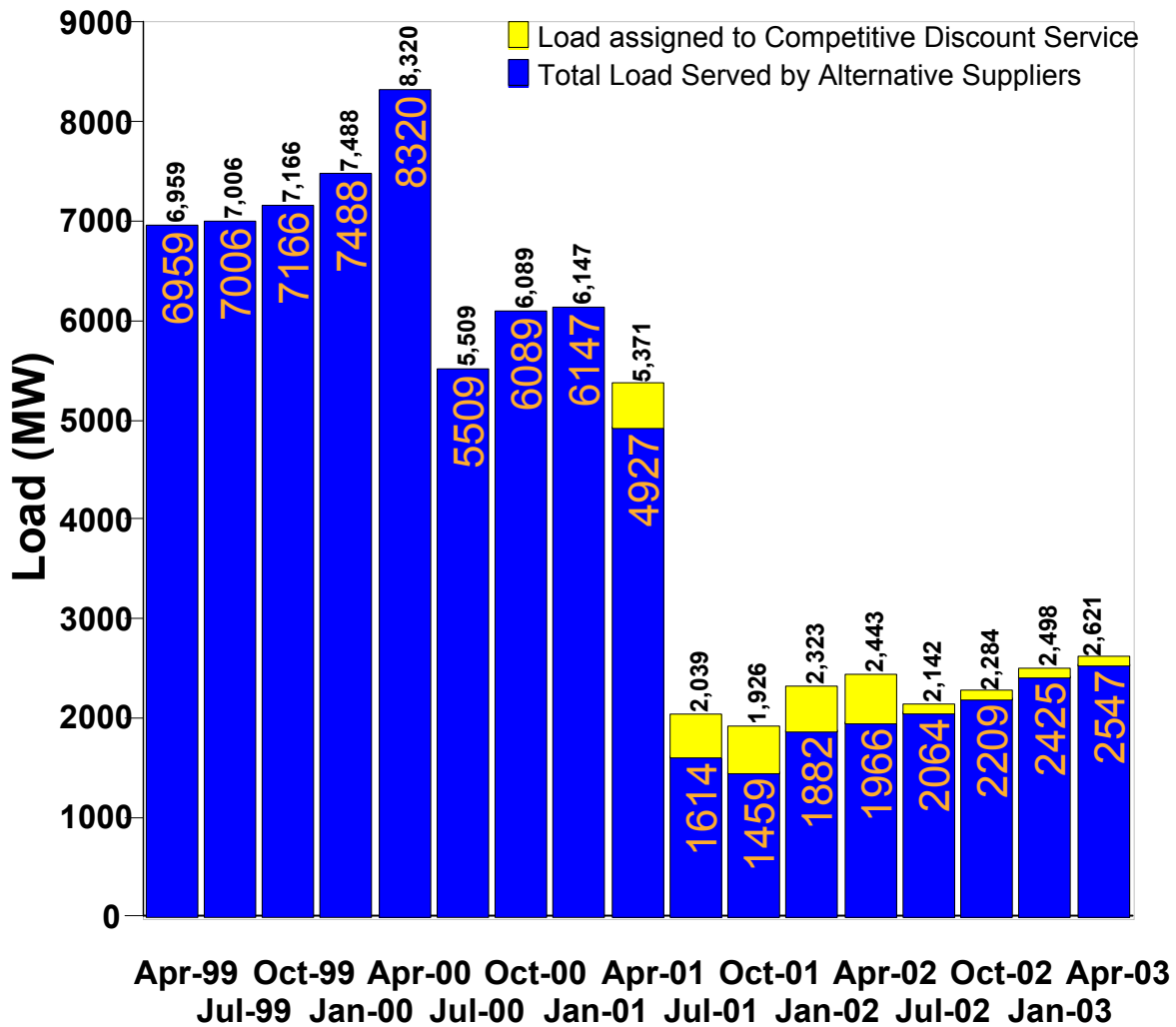
*MetEd and Penelec were formerly part of GPU.
 Data Source: Pennsylvania Office of Consumer Advocate

Figure II.6. Commercial customer switching in Pennsylvania.



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

Figure II.7. Industrial customer switching in Pennsylvania.



Data Source: Pennsylvania Office of Consumer Advocate

Figure II.8. Pennsylvania total load served by alternative suppliers.

Section III New England

Wholesale Market and ISO New England

ISO New England, Inc. was created in 1997 and operates the six-state New England region's¹ bulk electric power system and wholesale electricity markets. ISO New England developed out of the New England Power Pool (NEPOOL) that was created in 1971 from the integration of most of New England's utilities and municipal systems. This was primarily to enhance the region's system reliability in response to the northeast's 1965 blackout. ISO New England has interconnecting transmission lines connecting it to New York State and Quebec and New Brunswick in Canada. These lines are for the sale and purchase of electricity between the regions and for reliability purposes.

The New England power system serves about 6.5 million customers in an area with a population of 14 million people. The total market value is \$4.5 billion, with \$1.5 billion cleared in the spot market. There are over 350 power plants and over 8,000 miles of high-voltage transmission lines. New England system is a summer peaking system with peak demand in summer typically between 19,000 MW and 23,000 MW and winter peak demand between 17,000 MW and 19,000 MW. On August 14, 2002 a peak demand of 25,348 MW was reached, which is the current record peak demand for the region. The normal weather summer peak has increased by 20 percent over the last ten years.

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

¹The six states in ISO New England's region are Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

auctions to allow market participants to hedge against the possibility of paying transmission congestion charges under LMP in the day-ahead market.

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

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

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

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

²ISO New England Inc., "Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Electric Load Pocket," prepared by Levitan & Associates, Inc., July 1, 2003.

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

pipelines during a peak winter day as soon as by the winter of 2004/2005. This is due to the coincident natural gas and electric generation requirements during the heating season.

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

ISO New England's monthly average prices are charted in Figure III.1. This is the monthly average, on-peak monthly average, and off-peak monthly average prices

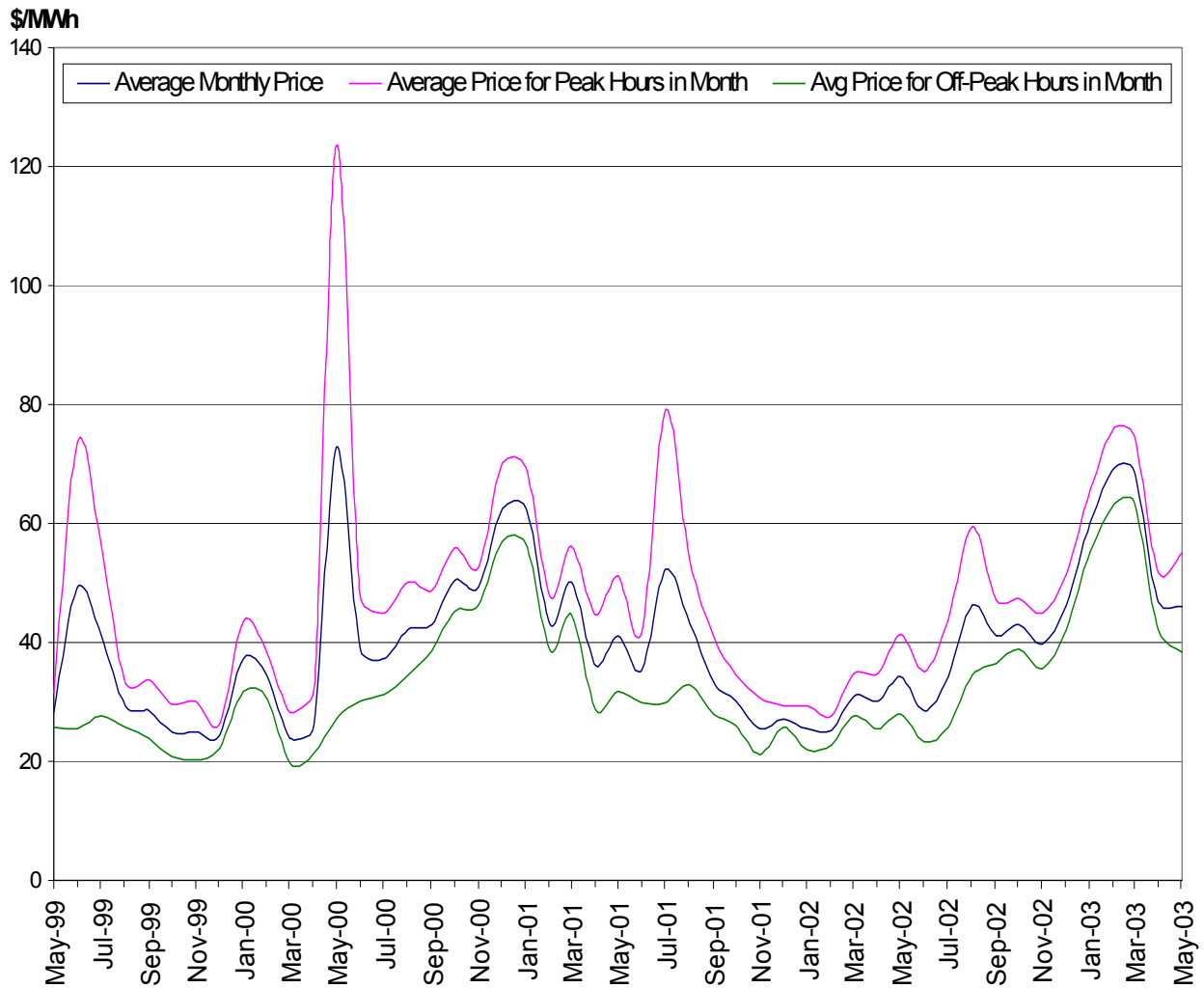


Figure III.1. Average monthly, average monthly peak, and average monthly off-peak prices in ISO New England, May 1999 through May 2003.
Source: ISO New England, June 2003.

for May 1999 through May 2003.⁴ The impact on prices from the hot weather in late July and early August of 2001 can clearly be seen and, as seen with most other power markets, the impact from the higher natural gas prices in early 2003. The ISO New England White Paper noted this strong link between natural gas and electricity prices and the potential negative impact this could have in terms of higher and more volatile prices due to the region's increasing dependence on natural gas.

Market Performance Analyses

Last year's report summarized a study of the New England ISO market by Bushnell and Saravia⁵ that used a similar "competitive benchmark analysis" as was used in the June 2002 Borenstein, Bushnell, and Wolak analysis of the California market (also summarized last year). This competitive benchmark is the estimated price that would result if all firms acted as price-taking firms—that is, no firm exercises market power.⁶ (The basis for examining wholesale market performance is discussed in Section I.) The study examined the period of May 1999 through September 2001. The results of the Lerner index estimation are summarized in Figure III.2 (this is an estimation using ISO New England, Energy Clearing Prices). The results are similar to

⁴For May 1999 through February 2003, prices are the monthly average clearing price, monthly average on-peak price, and monthly average off-peak price. For March 2003 through May 2003, the period when ISO New England began its Standard Market Design, prices are the average real-time LMP (the average hourly real-time hub or zone LMP for the month), on-peak LMP (the average real-time hub or zone LMP for peak hours in the month, where peak hours are hours ending 8:00 AM to 11:00 PM Monday through Friday excluding holidays), and off-peak LMP (average real time hub or zone LMP for the off-peak hours in the month).

⁵James 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.

⁶This is based on an estimated incremental cost of the cheapest unit that is not needed to serve demand in a given hour.

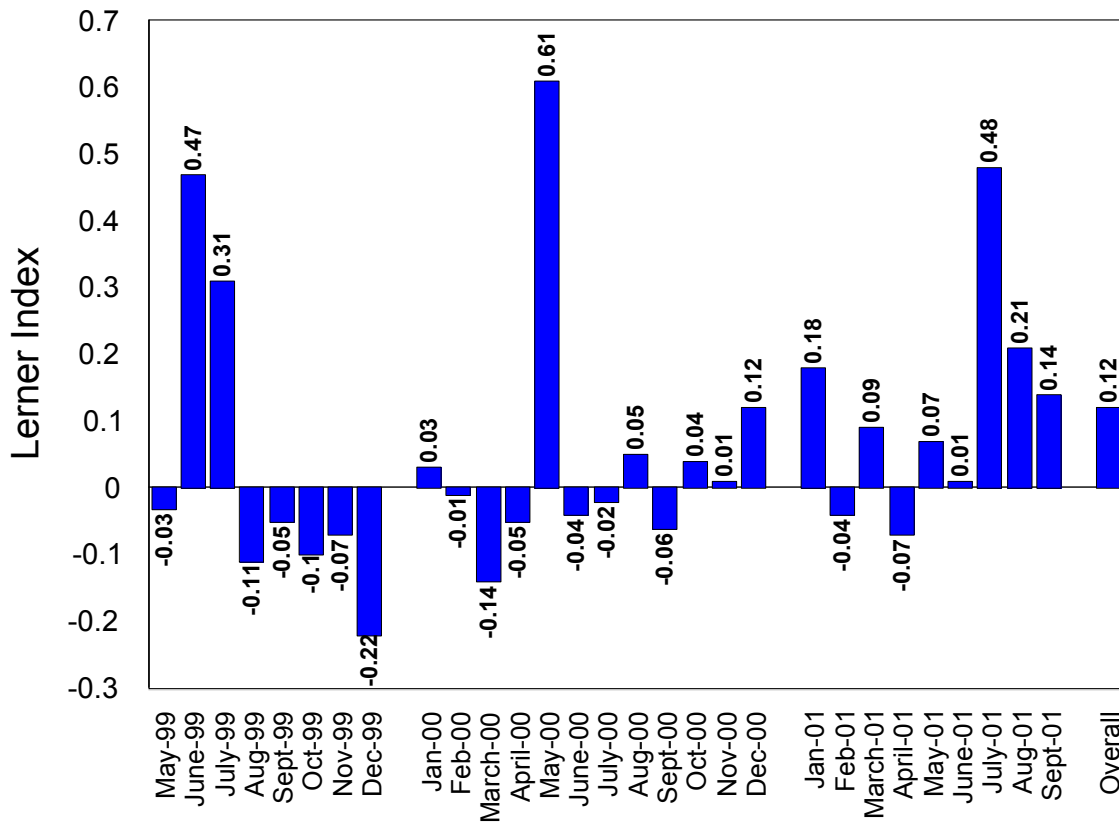


Figure III.2. Monthly Lerner index for New England electricity market, May 1999 to September 2001.
 Source: Bushnell and Saravia, “An Empirical Assessment of the Competitiveness of the New England Electricity Market,” May 2002.

the California estimation with relatively higher indices during the summer months, but without the 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 III.3. The graph is flatter than for California and 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 Lerner Indices were presented in Section II of this report.

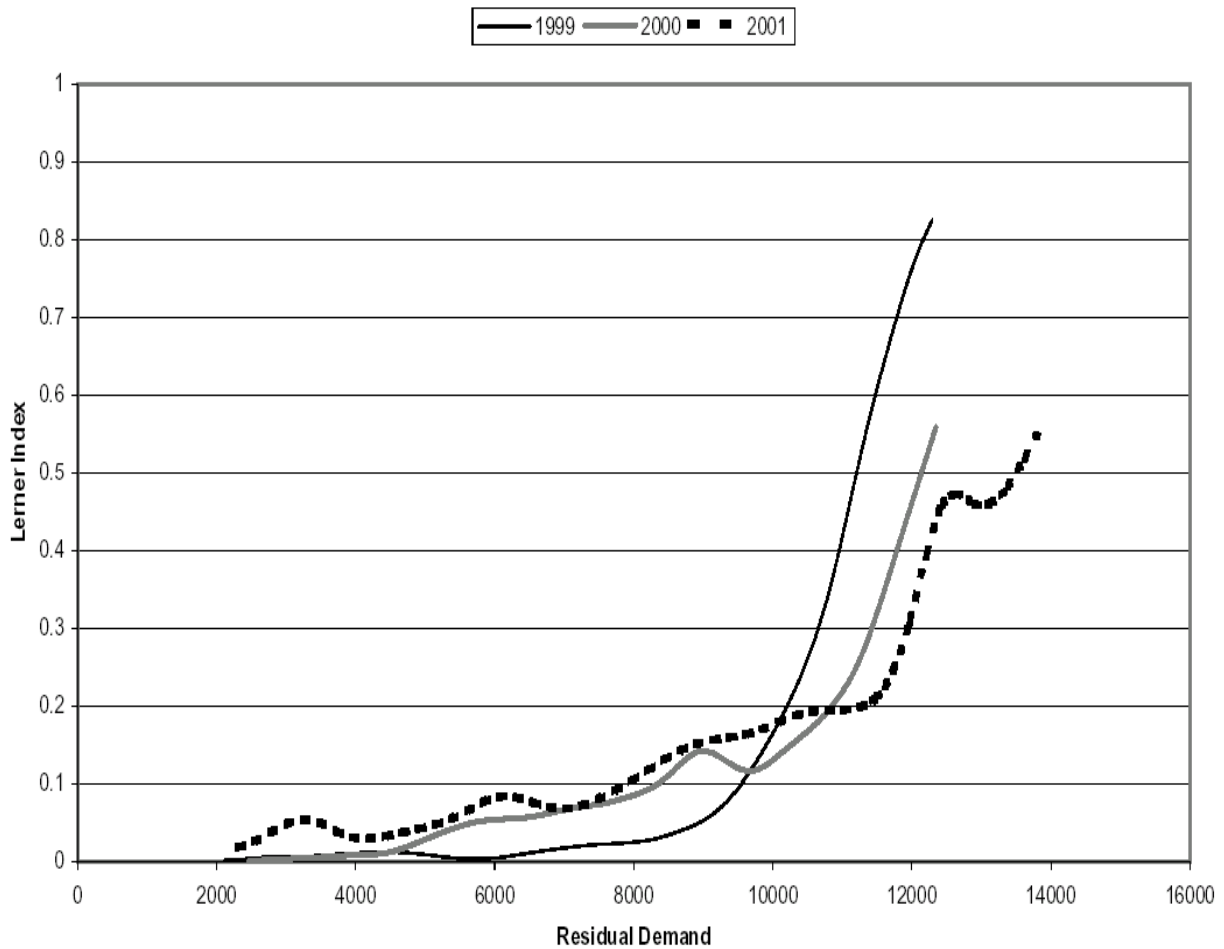


Figure III.3. The relationship between the level of demand and the Lerner index for New England.

Source: Bushnell and Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," May 2002.

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 expiration of transition periods and potential consolidation of supply portfolios will reverse this effect.⁷

Another analysis by the Independent Market Advisor to ISO New England,⁸ takes a different approach by examining attempts to exercise market power by suppliers through withholding generating resources from the market. Their analysis tries to differentiate anti-competitive withholding of supply resources from what could be regarded as ordinary competitive behavior. In their “withholding analysis,” they calculate an “output gap” that is defined as the difference between a unit’s capacity that is economic to supply at the prevailing market price and the capacity that is actually supplied. They conclude from their analysis that the New England wholesale market is “workably competitive.” They find “little evidence of persistent economic or physical withholding,” but that “it cannot exclude the possibility that discrete instances of physical withholding occurred.”

The Independent Market Advisor also examined the highest-priced hours during the summer of 2001 to determine whether market rules or procedures, unjustified actions by the ISO, or withholding by suppliers contributed to the inflated prices. They find that the majority of these high-priced hours “were warranted based on the deficiency in internal resources” in the region. Market rules that may have allowed prices to be set at unjustifiably high levels when a deficiency did not exist were

⁷Bushnell and Saravia, p. 21.

⁸David B. Patton, Robert A. Sinclair, and Pallas M. LeeVanSchaick, “Competitive Assessment of the Energy Market in New England,” Independent Market Advisor to ISO New England, Potomac Economics, Ltd., May 2002.

addressed by the ISO's pricing reforms. Based on their analysis, they state that "no clear evidence was found that economic or physical withholding substantially contributed to inflating the energy prices in these hours."

The Independent Market Advisor's economic withholding analysis is based on calculating a proxy marginal cost or "reference price" for each unit. This is to make the comparison with what would be economic for the unit to supply at the market price given the unit's marginal cost and what was actually supplied by that unit. In Appendix B of their report, they note that the reference price is calculated "based on an average of bids accepted in-merit for each unit." The assumption is that, in the absence of market power, suppliers will bid their marginal costs into the market. However, if there is supplier market power, which is at least part of the objective of which the analysis was to determine, then this method of calculating the reference price will likely overestimate the actual marginal cost and result in underestimating the "output gap" and possible economic withholding.⁹ This is because the relatively higher reference price (that is, what is being used for the marginal cost proxy) will result in fewer units being judged as withholding, since the reference price is higher than the market clearing price. In these cases, it is expected that the units will not sell power for less than what it costs to produce the power.

To test the results from the reference price, the Independent Market Advisor also estimates the output gap using an "alternative" competitive benchmark or reference price based on the variable production costs for each unit.¹⁰ While, as expected, the output gap increases with the alternative benchmark, the results still show a relatively modest amount of "output gap"—reinforcing the Advisor's conclusion that the New

⁹This is a fundamental difference between the two studies reviewed here. The Bushnell and Saravia study uses a "competitive benchmark analysis" which is based on a variable production cost estimate. The ISO New England Independent Market Advisor's "withholding analysis" is based on a benchmark (the first benchmark, not the "alternative" which is closer to Bushnell and Saravia's benchmark) calculated from supplier bids. Both are attempting to estimate supplier marginal costs, but with fundamentally different results.

¹⁰Independent Market Advisor, pp. 27 - 29.

England market is “workably” competitive and had only insignificant attempts to raise prices through economic withholding during the study period. However, the analysis is done using 110 percent of the variable production cost estimate and only for fossil units with “low out-of-merit frequency;” out-of-merit units are those that are dispatched even though the unit’s bid price exceeded the market clearing price. The analysis is not presented using all units or for different variable production costs levels to test the sensitivity of the alternative benchmark.

A Lerner index or market power markup is not calculated in the Independent Market Advisor analysis that could have allowed a comparison with the Bushnell and Saravia study. Such an index, presumably, could have been calculated based on the reference prices they calculate.

It should be noted that both these studies pre-date ISO New England’s implementation of Standard Market Design, which began March of 2003. This may impact the New England’s market performance over time.

Retail Markets

Five of the six New England states have retail access, Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island, and were among the first states to pass restructuring legislation and implement retail access. The five retail access states have been reviewed in previous reports—Maine and Massachusetts are updated below.

Maine

Maine's Restructuring Act required complete divestiture of transmission and distribution (T&D) utilities' generation assets. Maine chose to have the T&D utilities supply standard offer generation service to retail customers through a competitive process conducted by the Maine Public Utilities Commission. This has been done through a competitive bidding process or, if bids are insufficient or unacceptable to the Commission, through wholesale contracts. The T&D utilities themselves cannot participate in the bidding to become the standard offer provider and affiliates of the T&D utilities cannot provide more than 20 percent of the standard offer service in the

affiliated T&D utility's service territory. Maine has one type of default service, the standard offer service, for each of the three primary retail customer classes.¹¹ This standard offer serves all customers in the class that are not receiving power from a competitively-obtained supplier.

The Commission has, at this time, completed three sets of competitive bids and has a fourth underway.¹² Table III.1 summarizes the results of the three completed competitive bids that Maine has conducted. The Commission refers to the first two bidding experiences as meeting with "mixed results." For Maine Public Service (MPS), the bidding process has been able to obtain successful bidders in the first two years. However, MPS is in northern Maine and not part of the ISO New England control area. The Commission notes that while there has been some competition in this area, "there has been a limited number of suppliers active in the market."¹³ Also, the standard offer rate has been increasing since early 2001. The MPS current standard offer price for residential and small commercial customers has increased by 35 percent between early 2001 and the price that went into effect in March of 2003. Commercial and industrial standard offer prices have increased 37 percent and 56 percent, respectively. This may explain, at least in part, why most commercial customers (68 percent of the load) and nearly all the industrial customers (between 97 percent and 100 percent of the load since early 2002) in MPS are now served by competitive providers and are not on the

¹¹The primary customer classes in Maine are Residential and Small Commercial (demand less than 20kW, 25kW, and 50kW, for Central Maine Power (CMP), Bangor Hydro-Electric (BHE), and Maine Public Service (MPS), respectively), Commercial (greater than 20kW, 25kW, or 50kW for CMP, BHE, and MPS, respectively, but less than 400kW for CMP and less than 500kW for BHE and MPS), and Industrial (demand greater than 400kW for CMP and greater than 500kW for BHE and MPS). Maine also uses the corresponding categories, as in Table III.1, Residential and Small Non-Residential, Medium Non-Residential, and Large Non-Residential.

¹²This information is from an undated and untitled Maine Public Utilities Commission paper posted on the Commission's website. The first section is titled, "Detailed Summary of Standard Offer Bid Processes and Results."

¹³Maine Public Utilities Commission, "Standard Offer Study and Recommendations Regarding Service After March 1, 2005," December 1, 2002, p. 8.

standard offer price. However, about two-thirds of the residential and small commercial load remains on standard offer service. (Last year, the total number of customers served by MPS was reported at 35,467 residential, 193 medium, and sixteen large customers.) Customer switching by company are shown in Figures III.4, III.5, and III.6.

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

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

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

While the bidding process for Bangor Hydro-Electric (BHE) was unsuccessful the first two years at finding acceptable bids for all customer categories, Central Maine Power (CMP) was only successful for residential and small non-residential customers. By the third year, all customer categories for both companies were served by acceptable standard offer prices found through the competitive bidding process. The standard offer price has increased for residential and small commercial customers since 2000, increasing 22 percent in BHE's area and by 21 percent for customers in CMP's area. There has been no switching to competitive providers by residential and small commercial customers in either BHE's or CMP's areas (see Figures III.4 and III.5 below), consequently, all of these customers are on standard offer service. (There have been no direct offers to residential customers in the service areas of BHE and CMP since July 2001.) The contract for these customers has been in effect since March of 2002 and will remain in effect until February 2005. Currently all standard offer service prices for all customers classes for the three principle T&D utilities in the state have been procured through the competitive bidding process.

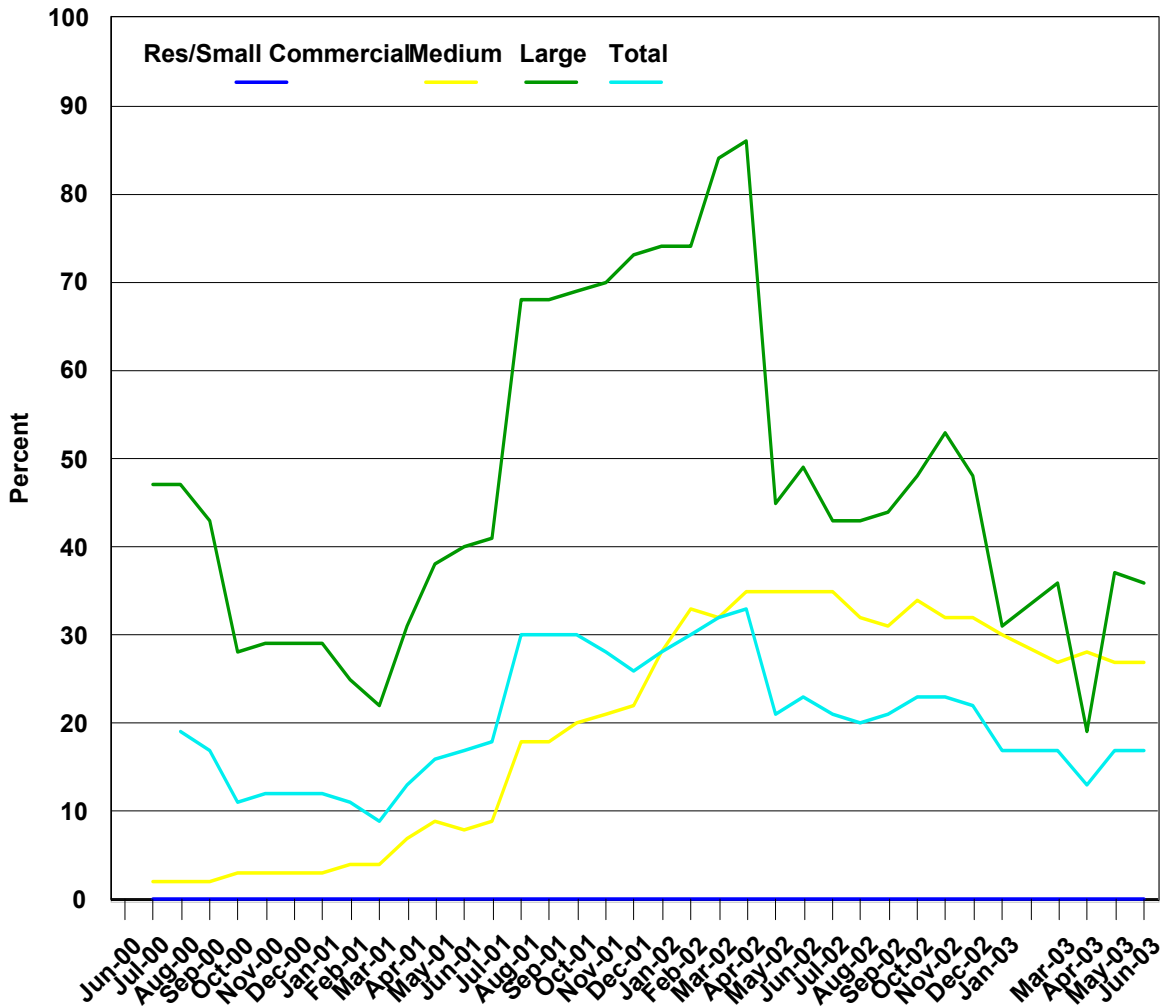


Figure III.4. Percentage of load served by competitive providers in Bangor Hydro-Electric Co.'s (BHE) service territory. (Note: No data was reported for February 2003.)
 Source: Maine Public Utilities Commission, June 2003.

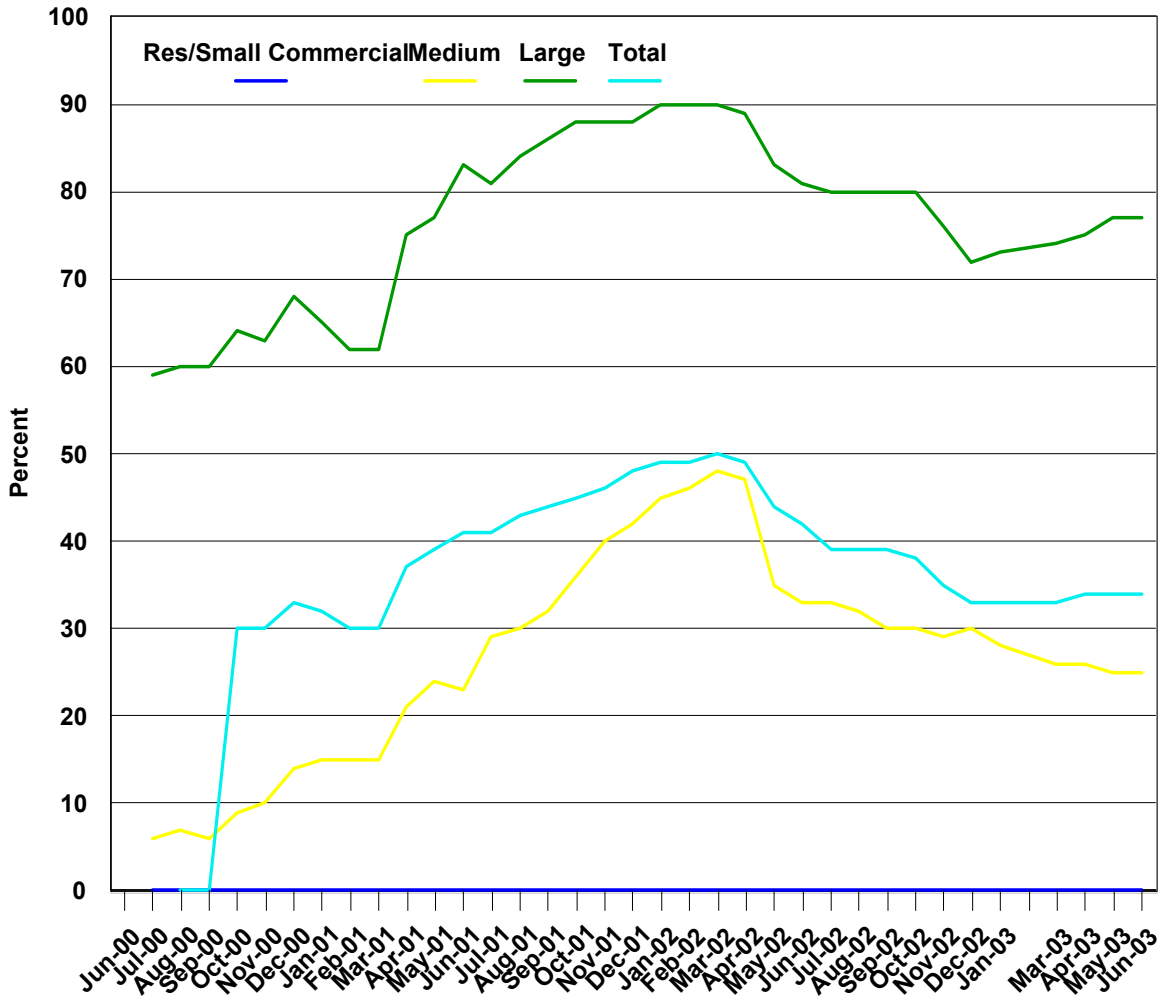


Figure III.5. Percentage of load served by competitive providers in Central Maine Power Co.'s (CMP) service territory. (Note: No data was reported for February 2003.)
 Source: Maine Public Utilities Commission, June 2003.

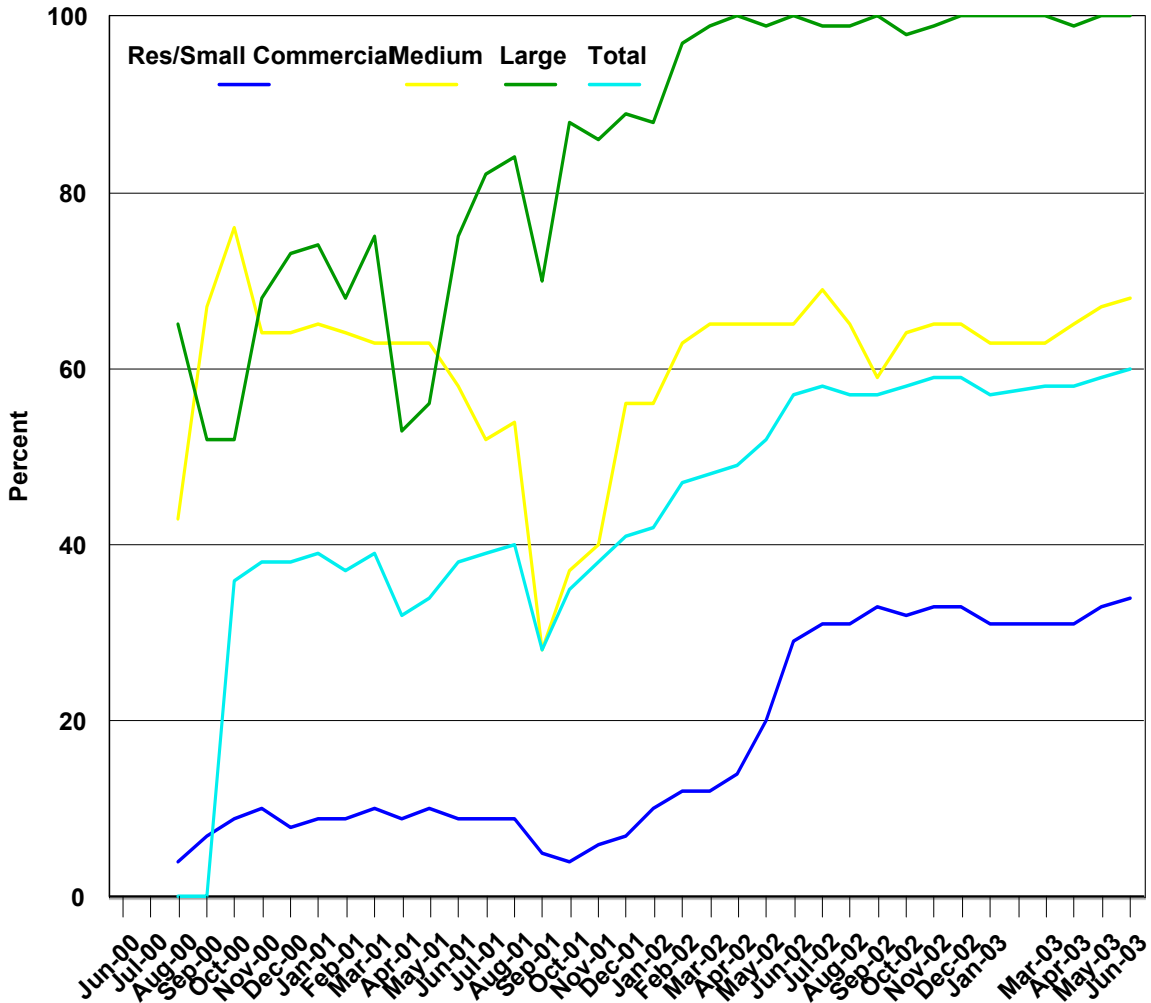


Figure III.6. Percentage of load served by competitive providers in Maine Public Service Co.'s (MPS) service territory. (Note: No data was reported for February 2003.) Source: Maine Public Utilities Commission, June 2003.

Massachusetts

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

While there has been an increase in residential customer activity since last year, statewide, it is still less than three percent of the customers that have switched to a competitive supplier. Figure III.7 shows the trends since April 1999 of the percent of customers choosing a competitive supplier by customer categories. The larger customer categories continue to show considerably more activity, however, there has been a marked decrease since the fall of 2002, especially for the large commercial and industrial customer group, which has fallen below 20 percent. Small and medium commercial and industrial customer groups also declined, both to less than ten percent of customers in each category. The pattern is similar in terms of kilowatt-hours, as shown in Figure III.8 below.

Figure III.9 is a cross section of customer switching activity for April 2003 to show where the activity is in terms of customer groups and kWhs by distribution companies. Commonwealth Electric (Comm Elec) clearly had the most activity for every customer group. For the larger customer groups, Massachusetts Electric (Mass Elec) had the second highest customer and kWh percentages. In terms of kWhs, all companies had large commercial and industrial customer switching above ten percent.

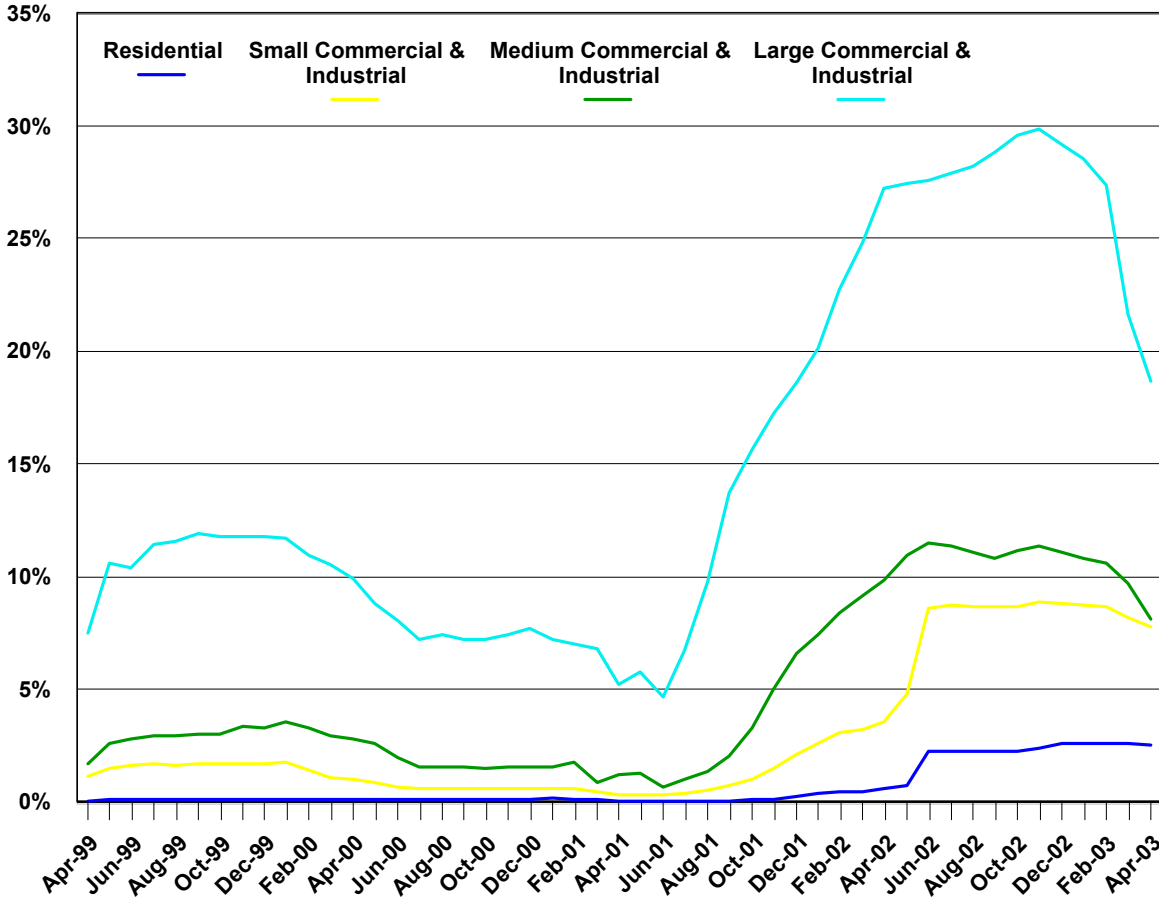


Figure III.7. Massachusetts percent of customers served by competitive generation, April 1999 to April 2003.*

Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," April 1999 through April 2003 reports.

*The percentage calculated for Large Commercial & Industrial customers for July 2002 was omitted because it appeared to be incorrectly recorded.

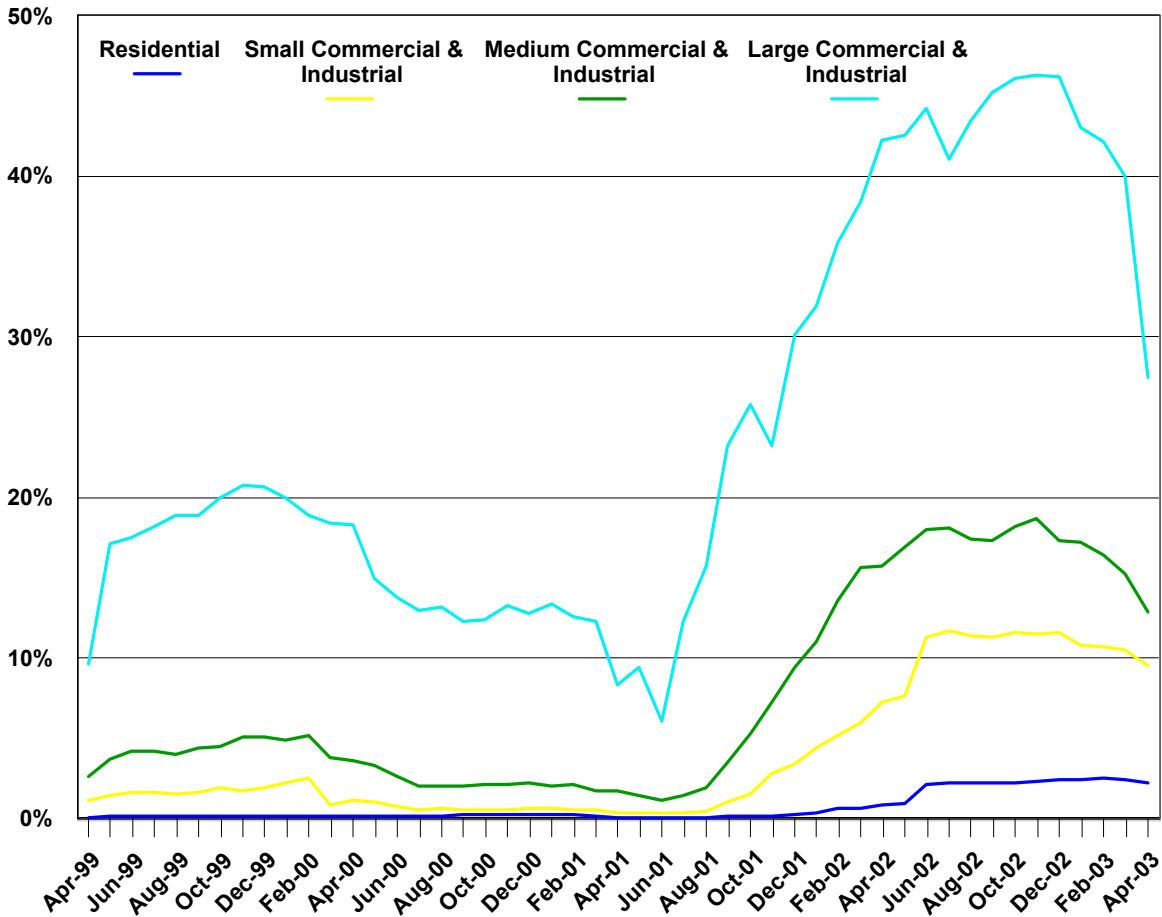


Figure III.8. Massachusetts percent of kWhs provided by competitive generation, April 1999 to April 2003.

Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," April 1999 through April 2003 reports.

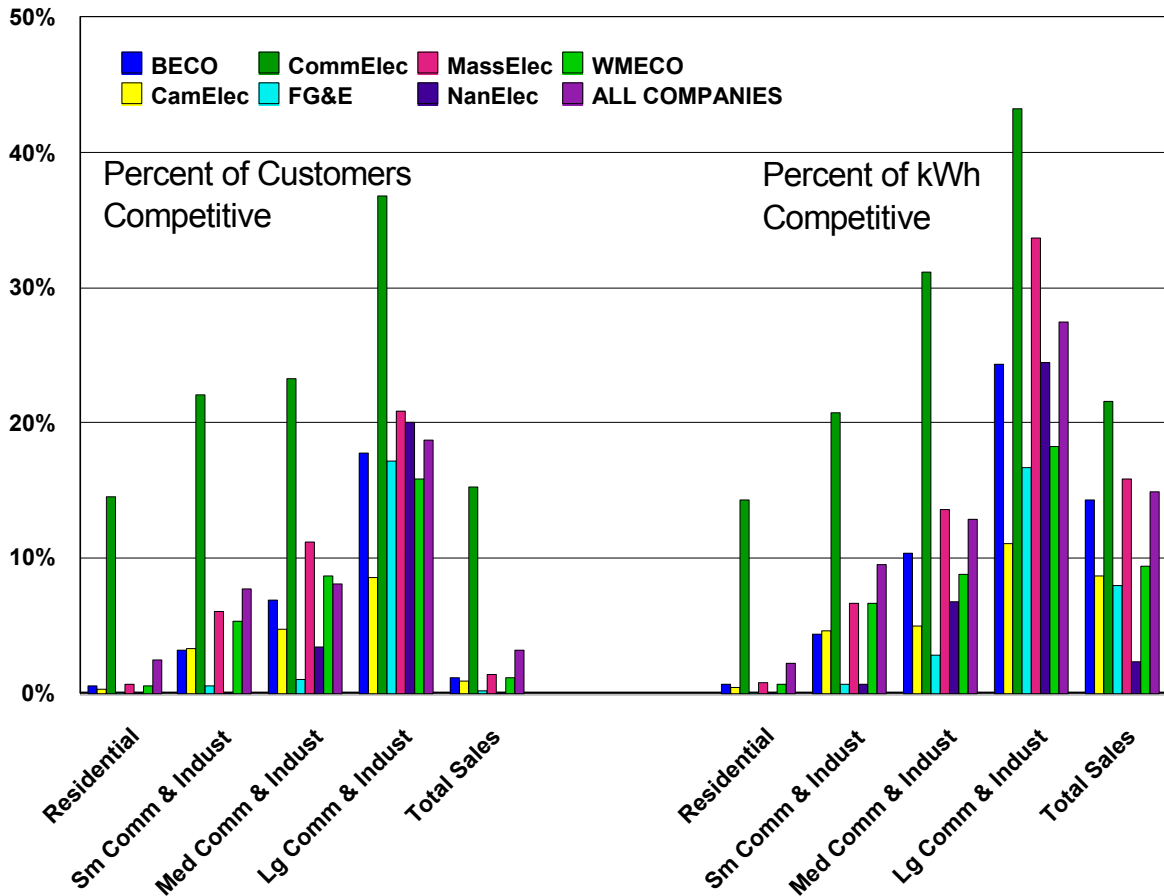


Figure III.9. Massachusetts company comparison by percent of customers and kWhs, April 2003.

Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," April 2003 report.

Section IV New York

Wholesale Market

Figure IV.1 shows the load weighted monthly average prices for the Day Ahead Market of the New York ISO from May 2001 to May 2003. As with other power markets around the country, the impact from the higher natural gas prices in early 2003 can be seen, when prices reached \$75 per MWh in February and March of 2003. Prices retreated to below \$50 per MWh in May. However, the price trend appears to be increasing since the low was reached in December 2001 of less than \$24 per MWh. Natural gas wellhead prices were about three and one-half dollars per Mcf in December 2001 and had dropped below three dollars in September and October of that year. Natural gas prices had spiked the previous winter of 2000/2001, peaking in January of 2001 at almost seven dollars per Mcf – which may, in part, explain the general downward trend from May 2001 to December 2001.¹

¹Natural gas wellhead prices are from the Energy Information Administration, U.S. Department of Energy.

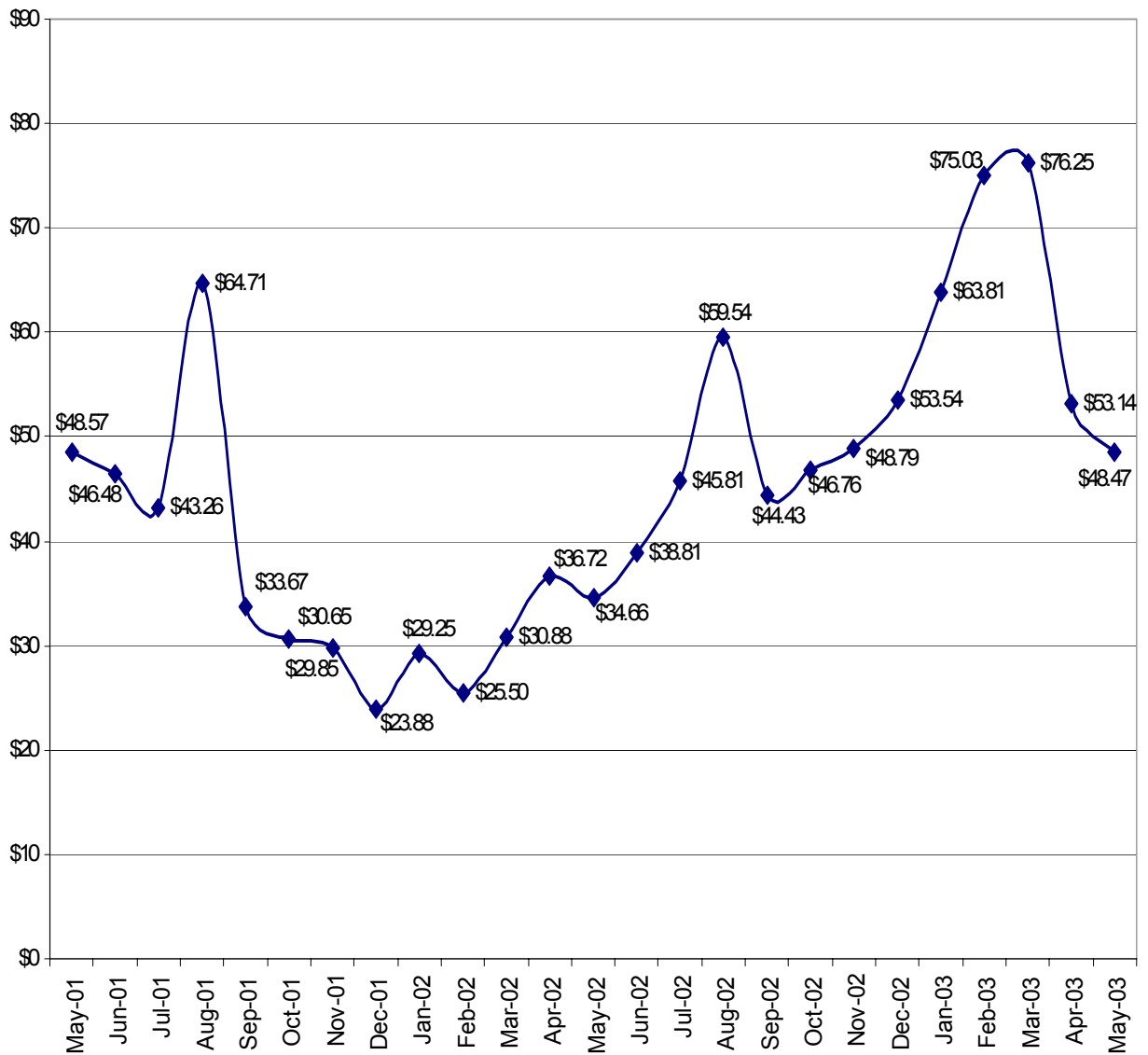


Figure IV.1. Load weighted monthly average Day Ahead Market prices (\$/MWh), May 2001 through May 2003.

Source: New York ISO, May 2001 through May 2003 reports.

*The May 2003 price is the load weighted monthly average Locational Based Marginal Price for the Day Ahead Market.

Retail Market

Figure IV.2 summarizes customer switching, or “migration,” in New York State and compares the 2002 percentages with 2003. The first graph in Figure IV.2, of all customer groups, shows that the most active shopping in the state is in the Orange and Rockland Utilities and Rochester Gas and Electric service areas.² As the other two graphs show, most of this activity is concentrated among non-residential customers. This pattern of activity holds for both 2002 and 2003. With a few exceptions, most areas had modest gains in the percent of customers switching to alternatives in 2003 compared to 2002. Since non-residential customers are the most active in the state, the percent of customer load that has migrated to alternative suppliers, as shown in Figure IV.3, is generally higher and, except for the Long Island Power Authority’s area, distributed across the state’s service territories. Non-residential customers in Rochester Gas and Electric’s service area in particular, moved to over 65 percent of load for May 2003, the highest percentage for any area, customer group, and for both years. For residential customers, however, the Orange and Rockland Utilities and Rochester Gas and Electric service areas remain the most active for both years.

²The full company names that are abbreviated in the figures are as follows: CH is Central Hudson Gas & Electric Corp.; Con Ed is Consolidated Edison Company of New York, Inc.; LIPA is Long Island Power Authority; NMPC is Niagara Mohawk Power Corp.; NYSEG is New York State Electric & Gas Corp.; ORU is Orange and Rockland Utilities, Inc.; and RGE is Rochester Gas and Electric Corp.

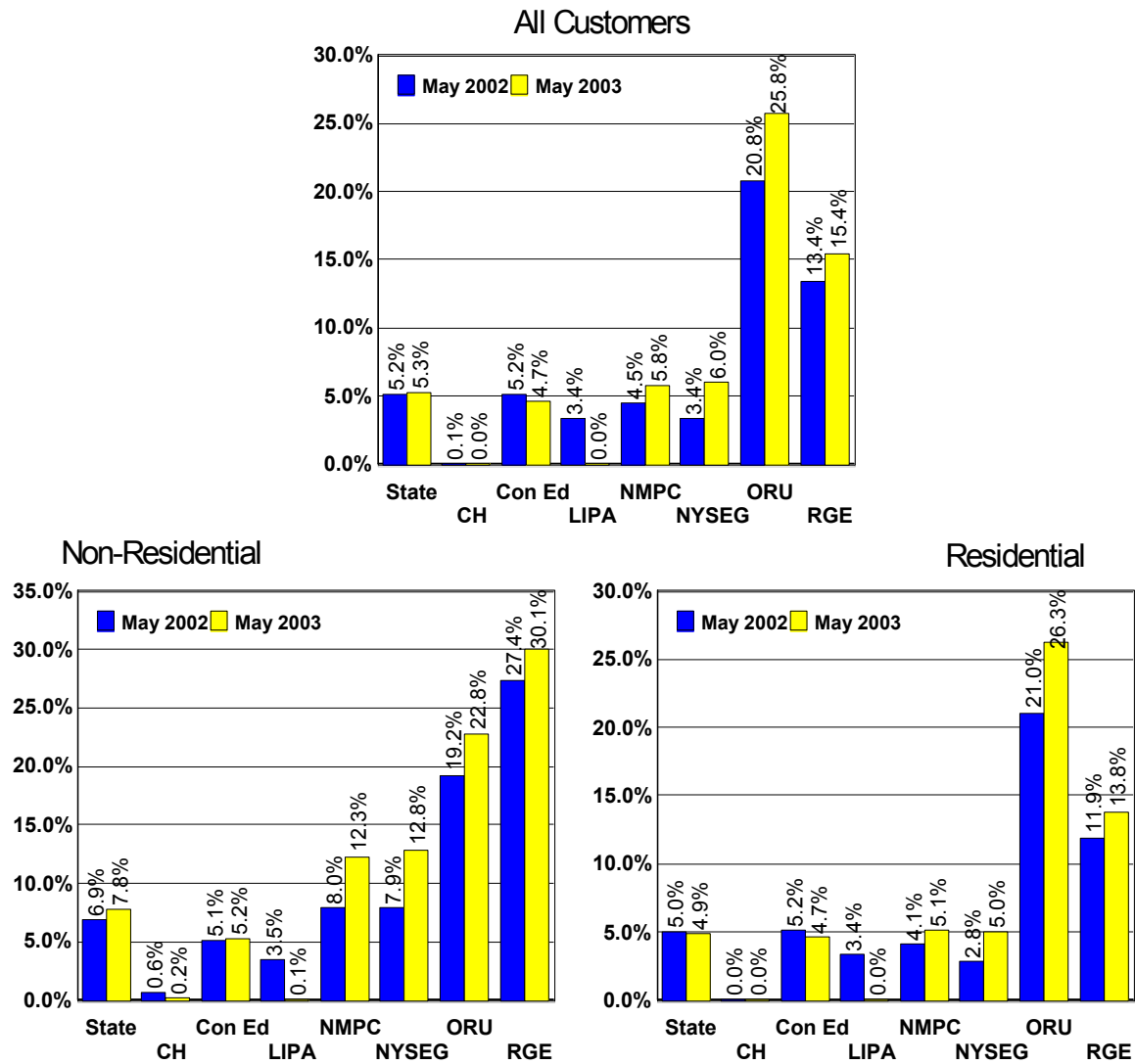


Figure IV.2. Percent of customer accounts migrated to alternative suppliers, by utility for all customers, non-residential customers, and residential customers, May 2002 and May 2003.
 Source: New York State Public Service Commission, May 2002 and May 2003 migration reports.

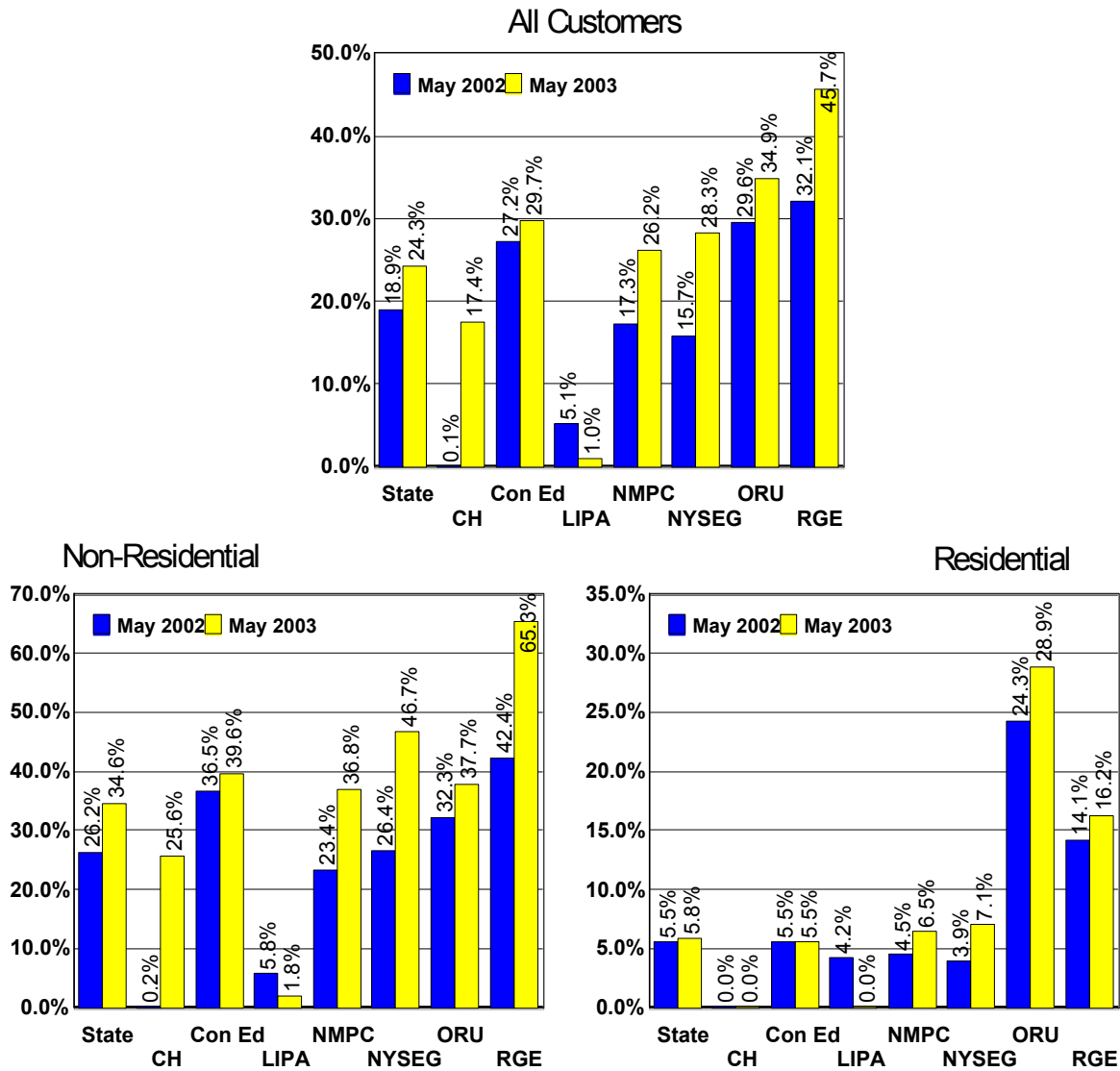


Figure IV.3. Percent of customer load migrated to alternative suppliers, by utility for all customers, non-residential customers, and residential customers, May 2002 and May 2003.

Source: New York State Public Service Commission, May 2002 and May 2003 migration reports.

Section V Midwest

Wholesale Market

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

A significant part of the Midwest region formed the Midwest ISO (MISO), which was founded in February 1996, to begin the process of forming a more tightly integrated regional system. MISO became the first FERC-approved RTO in December of 2001 and began operation in Feb. 2002 as a transmission provider. MISO covers an area that has 122,000 MWs of generation capacity with 111,000 miles of transmission lines. It covers a large area of the country that includes all or parts of 15 states and into Canada, or 1.1 million square miles, and with 16.5 million customers. Figure V.1 is a map that highlights the MISO’s geographic area.

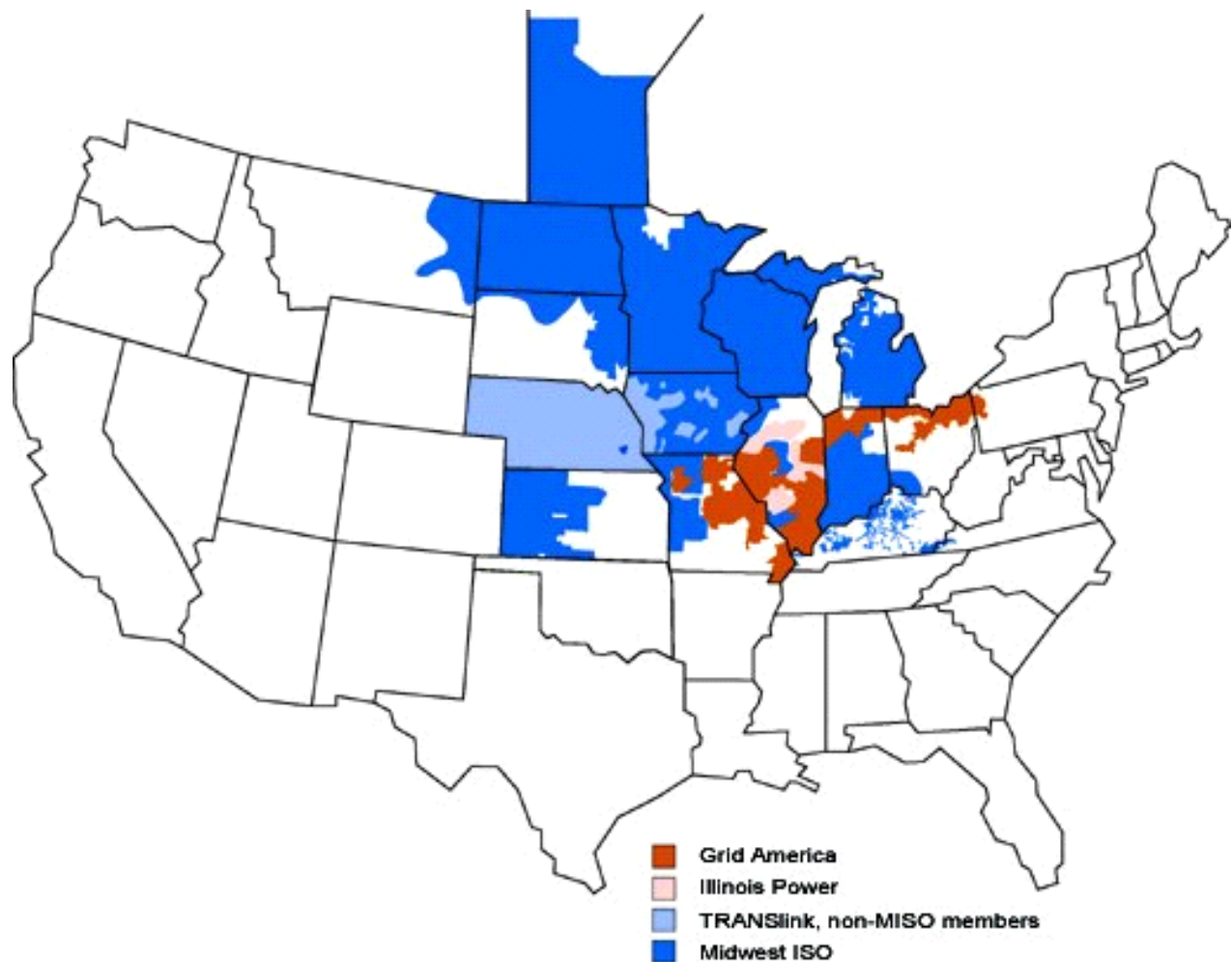


Figure V.1. The Midwest ISO region.
Source: Midwest ISO.

Currently, MISO is responsible for short-term reliability and interchange schedules. It now uses transmission loading relief (TLR) for congestion management, but plans to implement an LMP and FTR model, similar to other RTOs or ISOs. While there is currently no centralized market, MISO is planning to operate day-ahead and real-time energy markets. As a result, most transactions in the region are bilateral. The market launch date is, at this time, March 31, 2004 and market trials are scheduled to run from November 1, 2003 through February 2004. MISO also is the provider of last resort for ancillary services and market monitoring is done only for spot energy markets.

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

PJM, MISO, and TVA are attempting to form a “joint and common energy market” to coordinate power flows across the three regions.

Figure V.2 plots the weighted average daily prices for several Midwestern trading hubs for June 2002 through June 2003. The data is from IntercontinentalExchange, an electronically traded OTC commodity market (the same data used in the overview for the natural gas price comparison). The prices generally move in tandem, except PJM-West, which is now more closely tied with eastern markets (primarily PJM). PJM West now covers parts of western Pennsylvania and Maryland, northern Virginia, most of West Virginia, and into southeastern Ohio. The plan is for PJM-West to extend beyond these areas and into more of the Midwest—including most of Ohio and into northern Illinois to the Iowa-Illinois border, with portions of Indiana and Michigan.

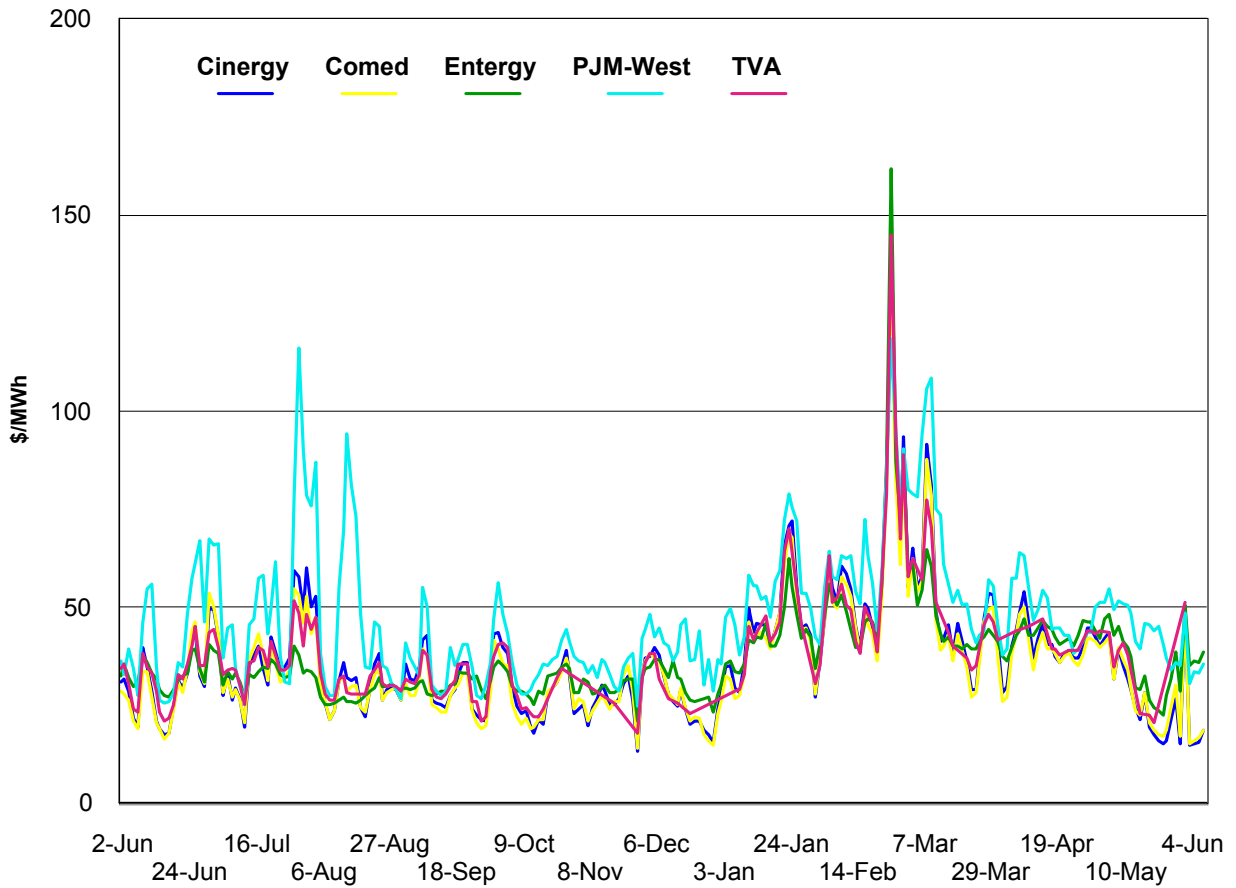


Figure V.2. Midwest trading hub daily prices, June 2002 to June 2003.
 Source: IntercontinentalExchange, Inc., www.intcx.com.

Retail Markets

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

Illinois

Illinois retail access for residential customers began on May 1, 2002. Also in May of 2002, the Illinois legislature extended the current freeze on electricity rates until 2007. At this time, there are no residential customers that have switched to an alternative supplier in the state. Also, several distribution companies are reporting no activity in their areas for all customer categories, including, AmerenCILCO Co., AmerenUE Co., Interstate Power and Light Co., and MidAmerican Energy Co. Three companies, AmerenCIPS Co., Commonwealth Edison Co., and Illinois Power Co., have had some customer switching, primarily among larger customers. Table V.1 contains the percent of customers that are receiving “delivery services.” This includes Interim Supply Service, Power Purchase Option, and Retail Electric Supplier customers. The Illinois Commerce Commission (ICC) defines Interim Supply Service as a tariffed short-term service available to delivery services customers who have no source of electric supply and Power Purchase Option (PPO) as an unbundled, market-based generation option that non-residential customers subject to transition charges must be offered. Both Interim Supply Service and PPO are supplied by the incumbent utility.³ Currently, according to the ICC, only two utilities, Commonwealth Edison and Illinois Power, charge transition charges to customers who receive delivery services.

The ICC reports that during 2002 over 40 percent of Commonwealth Edison’s delivery services customers switched to PPO. About 75 percent of AmerenCIPS’ delivery services customers and about 99 percent of Illinois Power delivery services customers under one MW were taking PPO service. About 80 percent of Illinois

³Illinois Commerce Commission, “Assessment of Competition in the Illinois Electric Industry in 2002,” April 2003.

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

Table V.1. Percentage of customers receiving delivery services, May 2003.

AmerenCIPS Company	Residential 0.0%	Commercial 1.5%	Industrial 12.8%	Total 0.2%		
Commonwealth Edison Company	Residential 0.0%	Small C&I 5.6%	Large C&I 59.2%	Govern mental 15.8%	Other 0.0%	Total 0.6%
Illinois Power Company	Residential 0.0%	Demand Less Than 1 MW 1.6%	Demand Greater Than 1 MW 32.5%	Total 0.2%		

Source: Illinois Commerce Commission, May 2003.

Table V.2. Percentage of Delivery Service Customers on Power Purchase Option, 2002.

Utility	Less Than 1 MW	Greater Than 1 MW
AmerenCIPS	75.4	54.5
Commonwealth Edison Co.	41.8	46.1
Illinois Power	99.4	80.3
Total	45.4	48.2

Source: Illinois Commerce Commission, "Assessment of Competition in the Illinois Electric Industry in 2002," April 2003.

Michigan

Michigan started retail access in January 2002. Table V.3 shows the percent of sales that have switched to alternative suppliers for Michigan's two largest investor-owned companies. While there is little activity among residential customers, there has been some activity with larger customer groups, particularly with industrial customers in Consumers Energy's territory and with commercial customers in Detroit Edison's territory.

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

	Consumers Energy	Detroit Edison
Residential	0.0%	0.006%
Commercial	5.3%	12.9%
Industrial	11.6%	7.8%
Total	5.6%	7.4%

Source: Michigan Public Service Commission staff, Department of Consumer & Industry Services, "Status of Electric Competition In Michigan: First Quarter 2003 Update," May 2003.

Ohio

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

PUCO. The utility needs to obtain approval of the PUCO for the corporate separation plan.

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

According to the PUCO, as of December 2002 a total of 756,411 residential customers and 848,702 customers of all classes had switched to an alternative electric supplier. The percentages of customers that switched to an alternative supplier for each distribution company is shown in Figure V.3. Cleveland Electric Illuminating Company⁴ had the highest percentage of all customers switching to alternatives of Ohio electric distribution companies and for all customer classes except industrial. Switching of its residential, commercial, and for total customers were all about 60 percent for each category. Ohio Edison had the highest percentage of industrial customers at over 30 percent. Toledo Edison also had a relatively high percentage of customers switching, with residential, commercial, and total customer categories at about 40 percent and industrial customers at 20 percent switching to alternative suppliers. For the other five distribution companies, no category exceeded five percent customer switching. Columbus Southern Power, Dayton Power and Light, Monongahela Power, and Ohio Power Company reported no residential customers had chosen an alternative supplier. Cincinnati Gas and Electric had less than three percent residential customer switching.

⁴The full company names of the abbreviations used in the figures are as follows: CEI, Cleveland Electric Illuminating Co.; CG&E, Cincinnati Gas and Electric Co.; CSP, Columbus Southern Power Co.; DP&L, Dayton Power and Light Co.; Mon Pwr, Monongahela Power Co.; Ohio Ed, Ohio Edison Co.; Ohio Pwr, Ohio Power Co.; Toledo Ed, Toledo Edison Co.

In terms of megawatt-hour sales, shown in Figure V.4, the pattern is similar for Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison, except for industrial sales for Toledo Edison which was below five percent. Also, there was considerably more activity for commercial and industrial sales for Cincinnati Gas and Electric and for Dayton Power and Light. It should be noted that Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison (all part of FirstEnergy Corporation serving northern Ohio) had the highest regulated rates among investor-owned utilities prior to restructuring and, consequently, higher prices-to-compare than other parts of the state.

Customer aggregation by local governments in the area of Toledo and by Northwest Ohio Aggregation coalition and NOPEC in other areas contributed to substantial switching in the services areas of Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison. As of December 2002, aggregation programs account for over 93 percent of residential, over 88 percent of the commercial and over 19 percent of the industrial customer switching in Ohio and over 92 percent of all customer switching in the state. Table V.4 summarizes the aggregation program switching.

Table V.4. Aggregation activity in Ohio, December 2002.

	Customer Switching through Aggregation	Total Customer Switching	Percent Switching through Aggregation
Residential	704,701	756,411	93.16%
Commercial	80,501	91,171	88.30%
Industrial	214	1,120	19.11%
Total	785,416	848,702	92.54%

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

As noted in last year's report, under an agreement with the PUCO and various parties, FirstEnergy agreed to make available 1,120 MW of "Market Support Generation" (MSG) to non-affiliated marketers, brokers and aggregators for sales to retail customers during the "market development period," which runs for five years beginning January 1,

2001. This capacity was made available on a first-come-first-served basis to competitive suppliers for committed capacity sales to FirstEnergy's customers. Of the total MSG capacity, 500 MW is reserved for residential customers. Total power allocations for the three northern Ohio FirstEnergy companies are 560 MW from Ohio Edison, 400 MW from Cleveland Electric Illuminating, and 160 MW from Toledo Edison. Prices for the capacity are based on customer class and increase each year that the capacity is made available. Industrial and commercial customer prices are the same for all three FirstEnergy companies, beginning at \$26.23/MWh and \$30.83/MWh respectively in 2001 and rising to \$31.88/MWh and \$37.19/MWh respectively in 2005. Residential customer prices for the MSG capacity are \$30.03/MWh for Toledo Edison, \$31.19/MWh for Ohio Edison, and \$31.64 for Cleveland Electric Illuminating. These prices rise to \$36.28/MWh, \$37.69/MWh, and \$38.24/MWh respectively in 2005. It is believed that these prices are initially below market prices for each customer class.

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

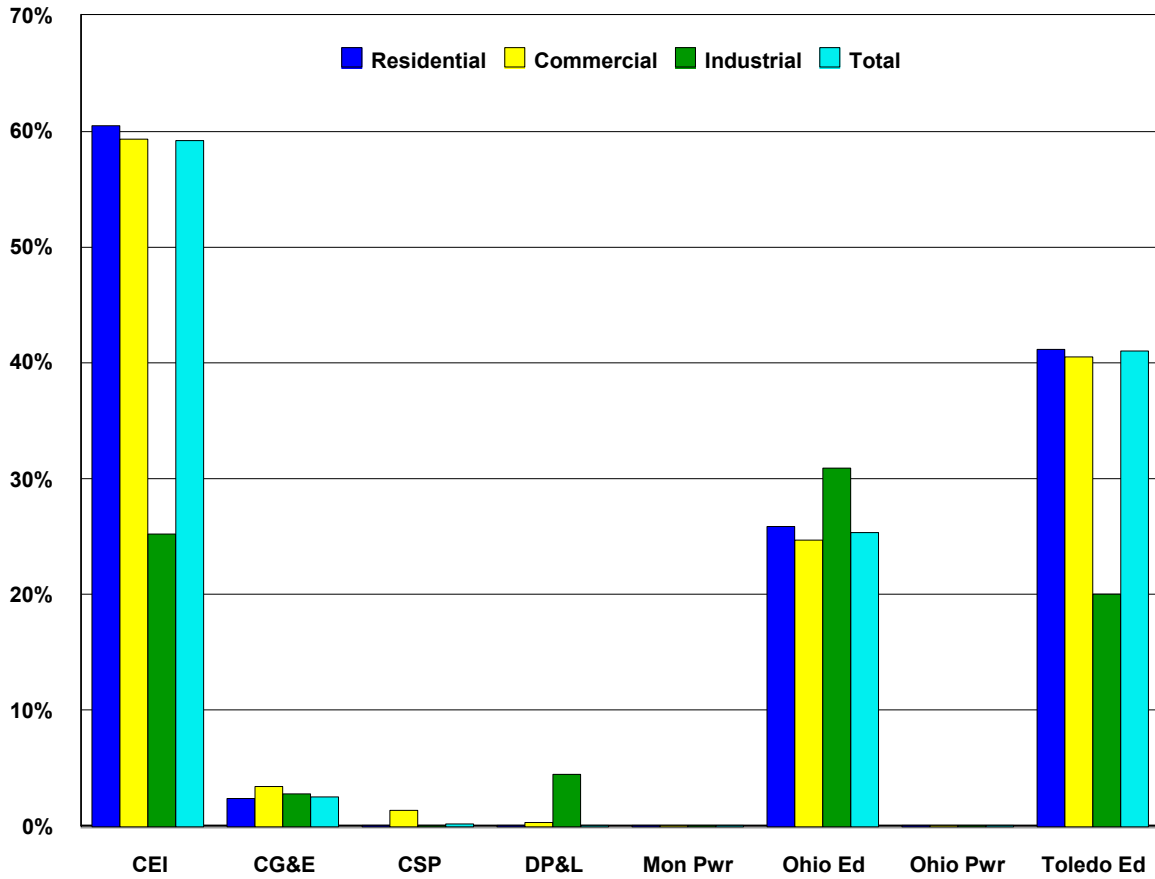


Figure V.3. Percent of customers that switched to alternative electric suppliers, December 2002.
 Source: Public Utilities Commission of Ohio, Division of Market Monitoring & Assessment.

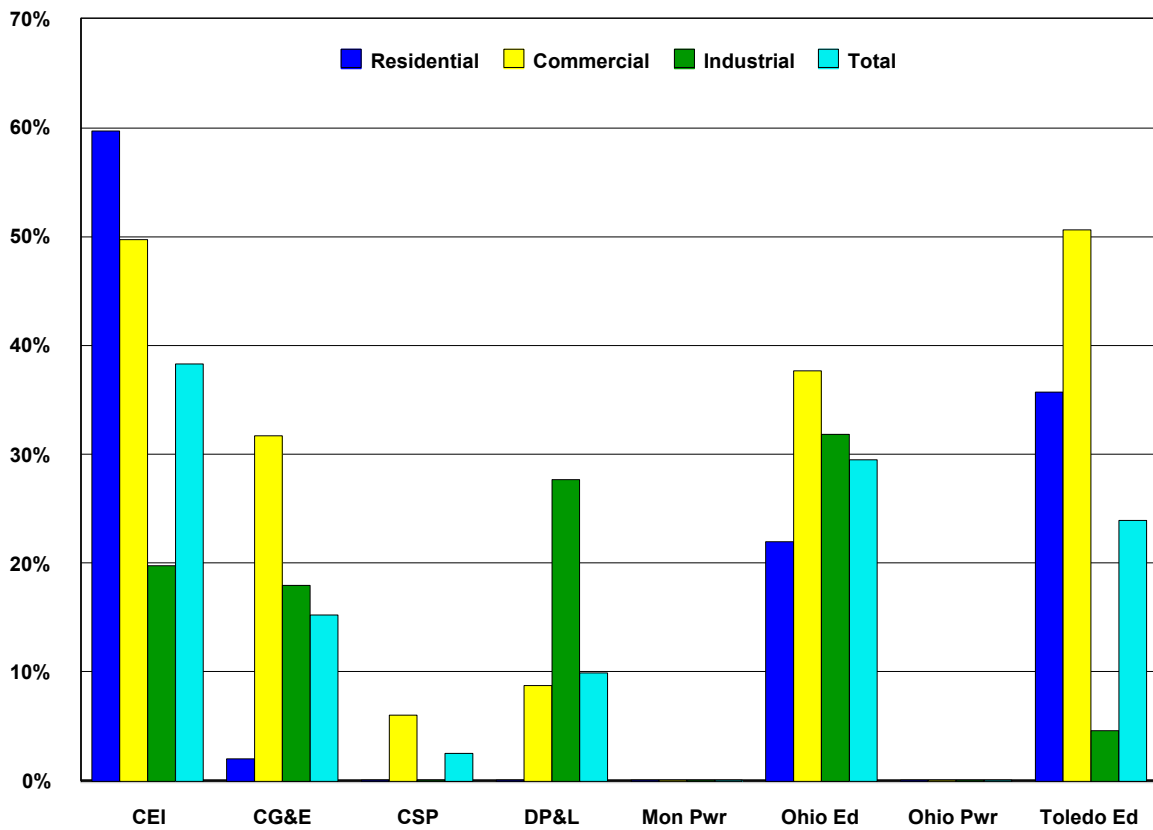


Figure V.4. Percent of megawatt-hour sales that switched to alternative electric suppliers, December, 2002.
 Source: Public Utilities Commission of Ohio, Division of Market Monitoring & Assessment.

Section VI TEXAS

Due to the apparent early success of its retail markets, Texas has attracted a great deal of attention across the country. Since its beginning in January of 2002, the Texas retail market has been one of the more active in terms of offers to residential customers and savings opportunities. This early success has led some to proclaim Texas as the model for both its retail access program and its wholesale market design. Because of the attention both the Texas wholesale and retail markets have received, this section is more extensive in this year's report than other regions that have been covered extensively in previous years.

Wholesale Market and the Electric Reliability Council of Texas

The Electric Reliability Council of Texas, Inc. (ERCOT) administers Texas' power grid and serves approximately 85 percent of the state's electric load, an area that includes about twelve million people. ERCOT is an independent, not-for-profit organization responsible for the transmission of electricity and is one of ten regional reliability councils in the North American Electric Reliability Council (NERC). It is one of two reliability regions that are also an ISO, PJM being the other. ERCOT has approximately 70,000 megawatts of generation and over 37,000 miles of transmission lines. ERCOT covers approximately 75 percent of the land area in Texas.

The Texas Public Utility Commission (the Commission) has primary jurisdiction over ERCOT activities and, because ERCOT is located completely within the borders of a single state, FERC does not have any jurisdiction. This provides ERCOT and Texas more latitude and flexibility in designing their wholesale power markets than other states that would also require FERC approval and oversight. Some believe that this also provides Texas with a better opportunity to coordinate the ERCOT portion of the state's retail and wholesale markets since both are state jurisdictional and the FERC is not involved. Outside of the ERCOT region, transmission access and pricing and wholesale

generation markets are under the jurisdiction of the FERC. Retail pricing and market operations remain under the jurisdiction of the Texas Public Utility Commission.

In May 1999, the Texas Legislature passed a bill to allow electric choice or retail access, which began for most consumers in January 2002. This required ERCOT to change its structure and functions. ERCOT is unusual among the existing RTOs and ISOs since it must deal with both retail and wholesale electric restructuring. ERCOT is still responsible for transmission reliability and open wholesale access, but is now also charged with overseeing the transactions related to the state's restructuring of the electric industry—including the development and operation of the ERCOT portion of Texas' competitive retail market. Restructuring of the electric industry in Texas makes ERCOT the central controller of the majority of the state's energy market activities, including power scheduling and troubleshooting.

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

ERCOT Market Operations

As noted, ERCOT's wholesale market is a market where participants use bilateral forward contracts almost exclusively, with zonal congestion management and the system operator running a minimal real-time balancing market. The Market Oversight

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

Division of the Texas Public Utility Commission noted that ERCOT is the only operating ISO/RTO-based wholesale market in the U.S. that uses only bilateral forward contracting among market participants. ERCOT's residual energy market for balancing energy, representing three percent to five percent of total demand, is for the reliability of the Texas electric grid. The Texas Commission has identified problems with its wholesale market design and has been formally considering changes.

Prices in the bilateral market that represents the bulk of delivered energy in Texas are based on mutual agreement or long-term contract between the parties, and are not known by ERCOT. These agreements are incorporated into base energy schedules which are submitted to ERCOT on a daily basis and account for about 95 percent to 97 percent of the end-user electric energy requirements in ERCOT.

Ancillary Services

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

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

Capacity Adequacy

ERCOT currently has no formal capacity market comparable to PJM's capacity credit market. The Texas Commission is developing a generation adequacy rule which

likely will use a mechanism that differs from capacity credit markets in the northeast region of the U.S. ERCOT utilities have traditionally sought to maintain a planning reserve margin of 15 percent. Because the system cannot rely on imports, due to its isolation from surrounding interconnections, relatively high reserve margins are thought necessary. However, in mid-2002, the ERCOT Board approved a 12.5 percent reserve margin requirement.

In 2000 and 2001, the reserve margins at peak were 14 percent and 21 percent, respectively. From 1995 to January 2001, 22 new generating plants, totaling more than 7,600 MW, were built in the ERCOT region. This represents 10.9 percent of total generating capacity; during this same period, peak demand grew by 24.5 percent. The Texas Commission reports² that statewide (ERCOT and non-ERCOT regions of the state) 55 plants for a total of 21,685 MW were completed from 1995 through early 2002. Also, in early 2003 it was reported that 12 plants with a total of 8,781 MW were under construction, 16 plants with a total of 8,047 MW had been announced or planned, and 13 plants totaling 7,180 MW had been delayed. (Earlier Commission numbers indicated that more than 9,700 MW of announced new generation capacity had been delayed and more than 4,400 MW had been cancelled.) These capacity additions have been mostly natural gas combined cycle plants and wind turbines. American Electric Power (AEP) and CenterPoint Energy announced in the fall of 2002 that they plan to mothball a total of 7,000 MW of older, less-efficient generating capacity. ERCOT is currently expecting its 2003 reserve margin to be over 32 percent and remain above 23 percent through 2008.³

The Commission has opened a rulemaking project to determine whether the adequacy of reserve margins should be left to market forces, or whether other means should be created to help ensure a minimum reserve margin.

²These data on new plants in Texas are from a presentation by Commissioner Brett A. Perlman, "Setting a New Agenda for the Restructured Electric Industry," at the "Give Your Customers a Break" Seminar, Atlanta, Georgia, August 8, 2003.

³Commissioner Brett A. Perlman presentation, "Setting a New Agenda for the Restructured Electric Industry," August 8, 2003.

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

ERCOT introduced monthly and annual Transmission Congestion Rights (TCRs) auction markets in February of 2002. TCRs were implemented in ERCOT along with the implementation of direct assignment of interzonal congestion charges. ERCOT initially adopted a simple flow-based transmission right approach and flow-based congestion charges.

Bilateral Market Prices

Figure VI.1 shows the daily power and natural gas prices in ERCOT from January 2001 to September 2002. Since August 2001, power prices have remained below \$50 per MWh. The figure also shows how power prices in ERCOT, similar to most of the country, is very dependent upon natural gas prices (except for a period during the summer of 2001). The reason, as discussed in the overview section of this report, is because natural gas-fueled generation is often the marginal unit dispatched for most power regions, including ERCOT.

The Commission attributes the price spikes for several days in August 2001 to transmission congestion that occurred on these days. They note that prices in 2002 have been usually below \$40 per MWh, even during the summer months. The Commission attributes this to the significant amount of new generation built in ERCOT over the last several years, along with lower than expected demand due to the nationwide economic slowdown, and cooler weather during the peak demand periods.

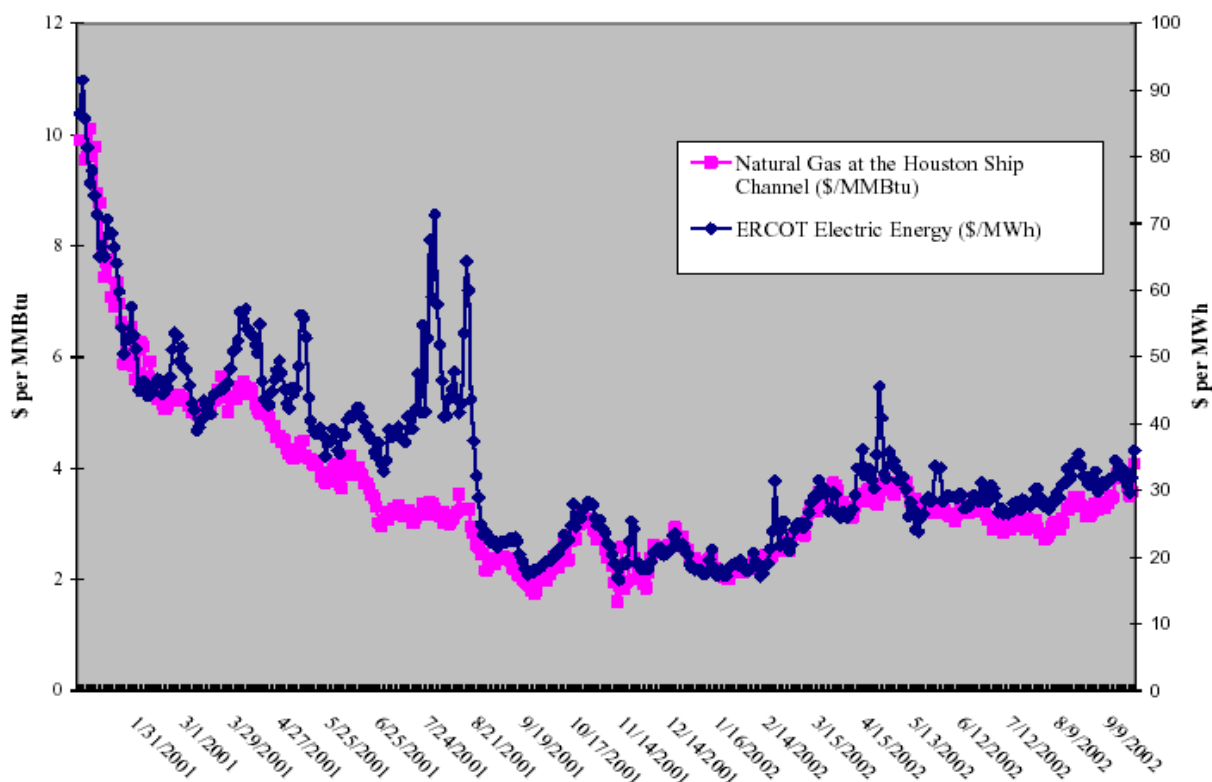


Figure VI.1. Daily ERCOT Energy Prices and Natural Gas Prices.
 Source: Public Utility Commission of Texas, January 2003, p. 78.

Real-Time Balancing Energy Market

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

Figure VI.2 is a chart of the ERCOT weighted average prices for energy from August 2001 through July 2002. The Commission reports that the average daily price

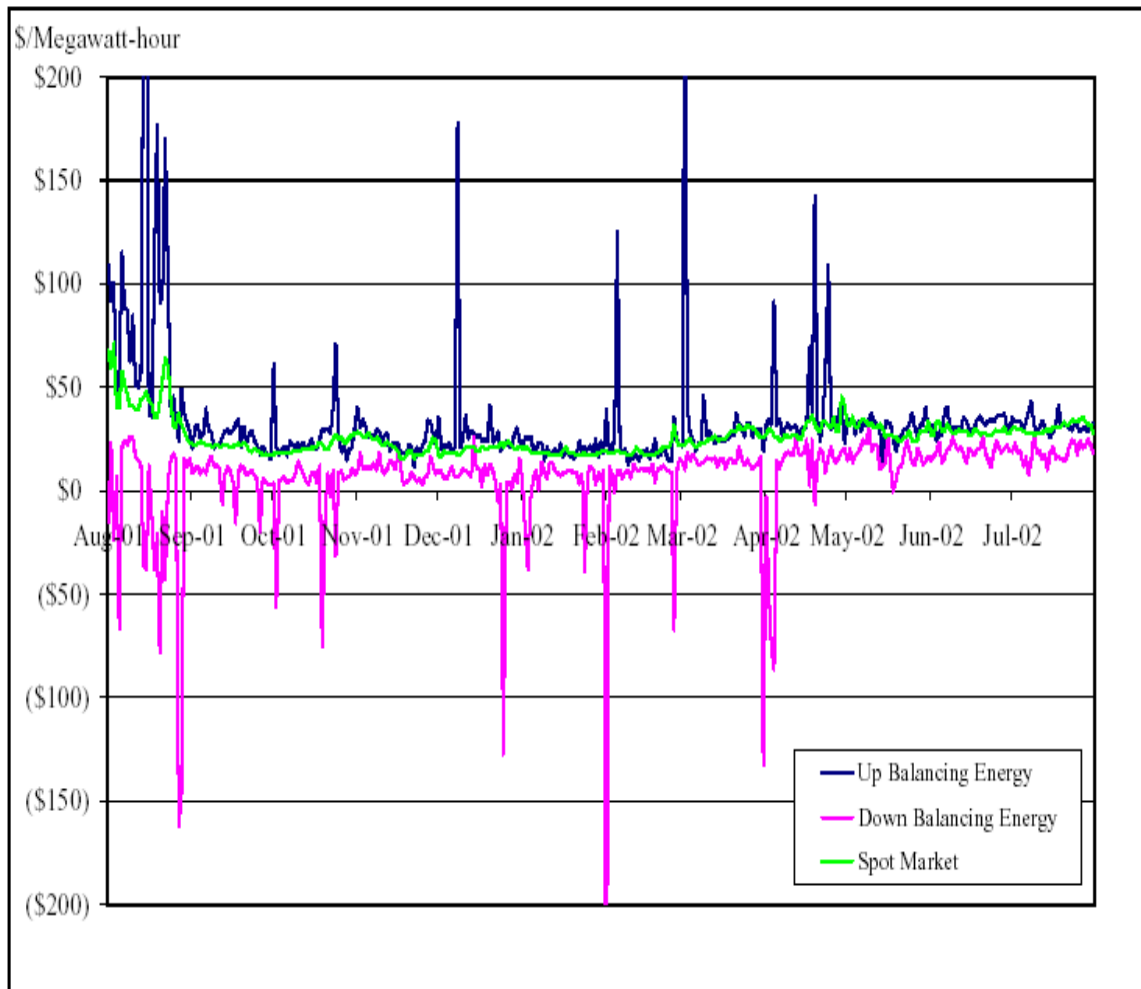


Figure VI.2. Weighted average price for Energy, August 2001 to July 2002.
 Source: Public Utility Commission of Texas, January 2003, p. 80.

for balancing energy was within the plus or minus \$50 per MWh range 90 percent of the time. The Commission also reports that nearly 277 million MWh of energy were consumed in ERCOT from August 2001 through July 2002, but less than five percent of total energy was transacted through the balancing energy market. The negative prices for down balancing energy represents the amount that ERCOT will pay the generator to reduce its output while ERCOT assumes the operational and financial responsibility to serve the load that was dedicated to the amount of reduced generation.

Figure VI.2 also shows the ERCOT energy spot market prices, as reported in Megawatt Daily, for comparison with the prices for up balancing energy and down balancing energy. Up balancing energy tends to be higher with occasional spikes than the spot market, while the down balancing energy tends to be lower than the spot market with downward spikes. The Commission attributes the price spikes to several possibilities, including a generator “forgetting” to place bids that resulted in a “lean” bid stack to misjudging weather conditions and not having the resources available.

Texas Retail Market

Overview

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

The Legislature delayed retail competition for utilities in the non-ERCOT regions of Texas, in the El Paso Electric service area until September 2005, (the end of the rate-freeze period from El Paso Electric’s bankruptcy proceeding in 1995) and in the Southwestern Public Service Company service area (in the Panhandle region of Texas) until 2007 at the earliest. The Southwestern Public Service Company service area is described as a transmission-constrained area that has limited access for alternative power generation companies and retail providers to serve customers.⁴ The Public Utility

⁴The Legislature required Southwestern Public Service Company to conduct an analysis on the need for additional transmission infrastructure and on plans to interconnect with other power regions.

Commission of Texas delayed the start of full customer choice for the Entergy, Southwestern Electric Power Company (SWEPCO), and a small portion of West Texas Utilities Co.'s (WTU)⁵ service area that is located within the Southwest Power Pool region. The Commission delayed competition for the Entergy and SWEPCO service areas because of three concerns: (1) a lack of independence in the administration of transmission service and uncertainty about the market rules for these areas; (2) a lack of testing of the technical systems needed to accommodate retail choice; and (3) a lack of necessary market institutions and lack of open and non-discriminatory access to the transmission grid.

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

The "Price-to-Beat"

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

⁵WTU is now also known as AEP Texas North, an affiliate Retail Electric Provider (REP) of AEP's Texas local distribution utilities. AEP Texas Central, also is still known by its former names CPL, Central Power and Light Company, or CPL Retail Energy.

affiliated retail electric provider. The affiliated REPs are required to sell electricity at the price-to-beat until January 1, 2007.

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

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

The price-to-beat rates for residential customers for each affiliated REP are shown in Table VI.1. In the case of First Choice/TNMP, CPL/AEP Texas Central, and WTU/AEP Texas North, base rates changed a level other than six percent due to changes in rates between January 1, 1999 and December 31, 2001 that resulted from merger proceedings. (See the sideline note on company names in Texas.)

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

Affiliated REP	December 31, 2001	January 1, 2002	September 2002	June 2003
TXU	9.67	8.25	8.66	9.70
Reliant/CenterPoint	10.40	8.62	9.12	10.10
First Choice/TNMP	10.57	8.66	9.15	10.10
CPL/AEP Texas Central	9.57	8.80	9.52	10.92
WTU/AEP Texas North	9.98	8.88	9.73	11.34

Source: Public Utility Commission of Texas, January 2003 and, for the June 2003, ENERGYguide.com.

The Commission reports that because of significant increases in the price of natural gas during the winter of 2000-2001, the fuel factor portions of the 2001 rates rose significantly and also required fuel surcharges to recover past uncollected fuel expenses. At the end of 2001, natural gas prices fell significantly, resulting in reductions in the fuel factor portion of the price-to-beat rates. Also, the fuel surcharges that were in place during 2001 terminated in December 2001. As a result, customers received in excess of a six percent reduction in their total rates as compared to rates in effect on December 31, 2001. Natural gas prices dropped in the early months of 2002, but began to rise significantly in

Due to mergers; the required unbundling of investor-owned utilities into three companies – (1) power generation company (PGC), (2) transmission and distribution utility (TDU), and (3) retail electric provider (REP); and other structural changes that companies in Texas have undergone in recent years, the names of companies have been changed or new names created. In this report, where possible, the names of the companies reported by the Commission along with the figures supplied are used in the tables and graphs. In the text, the company’s pre-retail access utility name is also given. Here is a summary of the utility, REP, or new names that are used:

- Central Power and Light Co. / CPL / AEP Texas Central
- HL&P / Reliant Energy / CenterPoint Energy
- Texas-New Mexico Power Co. / TNMP / First Choice Power
- TXU Electric & Gas / Oncor
- West Texas Utilities Co. / WTU / AEP Texas North.

March and April of 2002. All of the affiliated REPs (except TXU-SESCO) subsequently requested adjustments to their price-to-beat fuel factors in order to reflect increases in the price of natural gas in the range of 16 percent to 24 percent. Reliant Resources filed for a second adjustment in November 2002 to reflect a further seven percent increase in natural gas prices (that was approved by the Commission in December 2002). Figure VI.3 charts the changes in the bundled rates before retail access and the price-to-beat rates after (the slide is from a presentation of Chairman Rebecca Klein of the Texas Commission in May 2003).

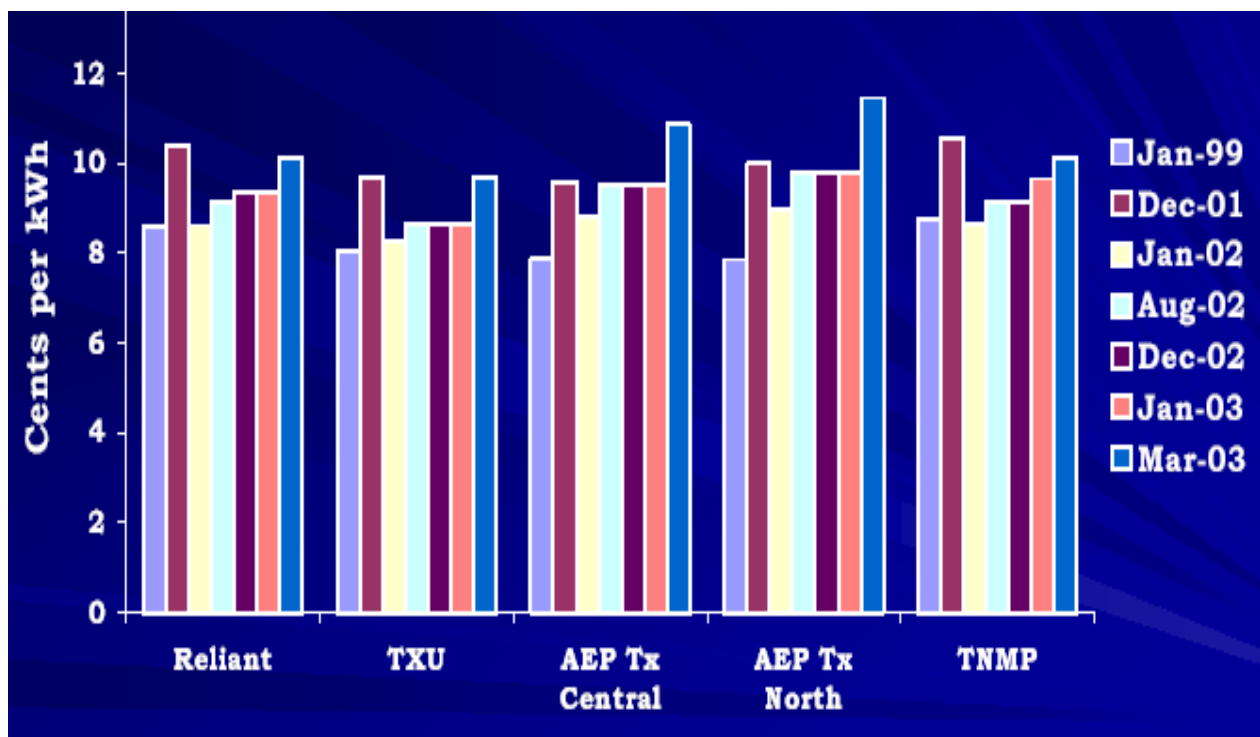


Figure VI.3. Pre-retail access bundled rates and the “price-to-beat,” January 1999 to March 2003.

Source: Slide from presentation of Chairman Rebecca Klein, Public Utility Commission of Texas, Competitive Retail Markets in Texas and Market Design,” Electric Power Supply Association, State Issues Meeting, May 6, 2003.

Provider of Last Resort (POLR) Service

In areas of the state where retail access is in effect, the Commission designates REPs to serve as providers of last resort or a POLR. The Commission adopted POLR

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

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

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

commercial and industrial customers for non-payment, unless an existing contract provides for different treatment.

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

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

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

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

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

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

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

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

Customer Choices

Texas continues to have the most active market in the country for residential customers in terms of offers and savings opportunities. In June 2003, as summarized in Table VI.3, residential customers had between four and nine competitive providers offering between four to eleven competitive offers (this count does not include the affiliated REP's standard service at the price-to-beat rate). All five areas have at least three offers below the price-to-beat rate, two areas had six offers, and one area had seven offers below the price-to-beat. As measured by the lowest offer, residential customers had an opportunity to save between eight percent and 24 percent off the price-to-beat rate. All service areas, except that of WTU/AEP Texas North, had three renewable, or "green," offers (all the green offers were from the same power provider).

Table VI.3. Residential competitive offer summary for Texas, June 2003

Utility	Number of Competitive Suppliers	Total Number of Offers from Competitive Suppliers	Number of Offers Below the Price-to-Compare	Number of Green Offers	Savings with Best Offer*
TXU/Oncor	9	11	6	3	13%
CPL/AEP Texas Central	8	10	7	3	21%
WTU/AEP Texas North	4	4	3	0	24%
Reliant/CenterPoint	9	11	6	3	16%
TNMP/First Choice Power	4	6	3	3	8%

*Calculated by comparing the Price-to-beat with the lowest offer in cents/kWh.
Source: Based on offers from ENERGYguide.com, collected in June 2003.

Figure VI.4 graphs all the residential offers in the five service territories made in late June 2003. This shows that all but one service area had offers at greater than ten percent savings.

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

dramatically. Customers who have negotiated fixed price contracts have been able to avoid the subsequent increase in prices that have occurred this year, albeit at a price that reflects their REP absorbing that risk. Generally, however, all customers have enjoyed prices in 2002 that were significantly below the regulated rates they paid in 2001.

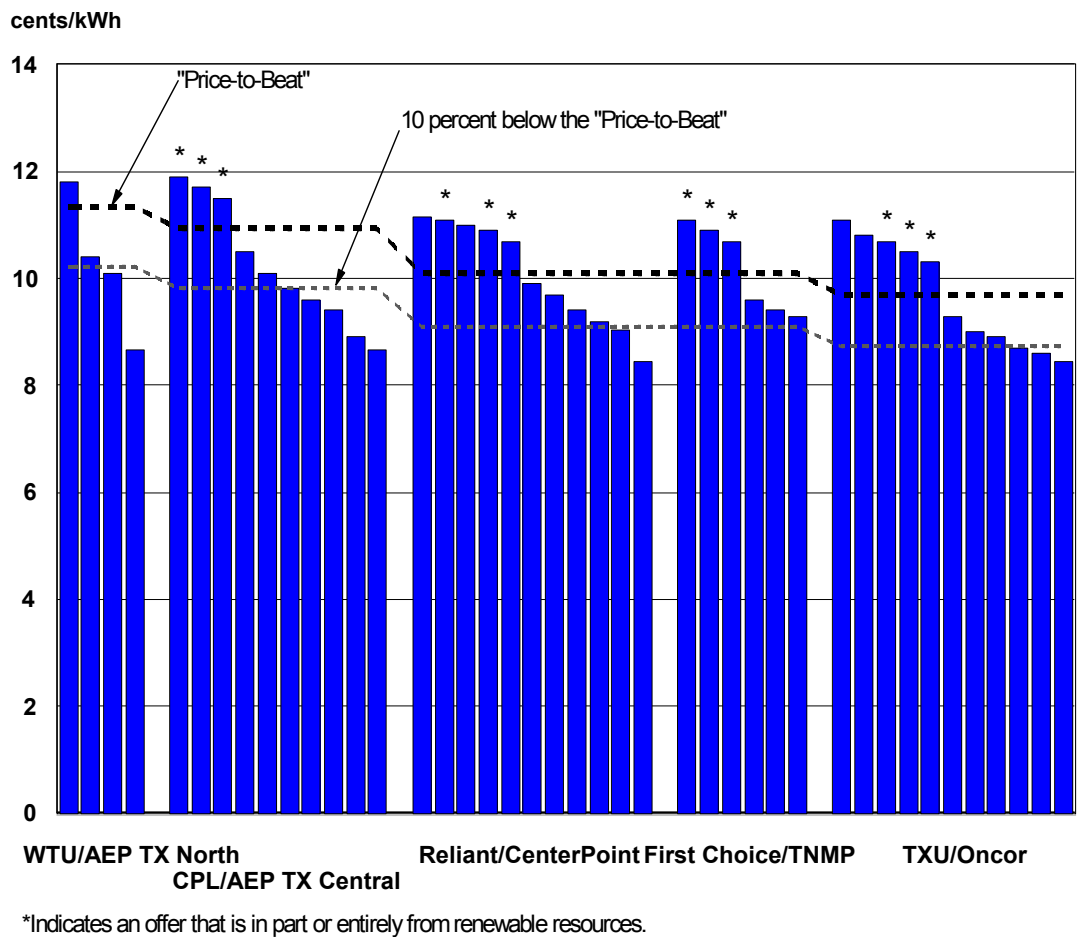


Figure VI.4. Residential offers in Texas retail markets, June 2003.
 Source: Based on offers from ENERGYguide.com, collected in June 2003.

Customer Switching

As Figure VI.5 shows, almost eight percent of all residential customers were served by a non-affiliated REP by December 2002. Both Oncor (TXU) and CenterPoint (Houston area, formerly Reliant Energy HL&P) service areas had over ten percent of residential customers being served by non-affiliated REPs in June of 2003. Figure VI.6 shows that CPL (AEP Texas Central) had the highest percentage of secondary voltage customers (primarily smaller commercial and industrial customers, most of which are eligible for the price-to-beat) receiving power from competitive REPs. Over eleven percent of all customers in this category were with a competitive REP in December 2002.

The Commission notes that although less than ten percent of all secondary voltage customers (68,133 customers) have switched, as reported for September 2002, the customers who have switched are among the largest customers in this customer class since about 25 percent of the MWh (about 1.8

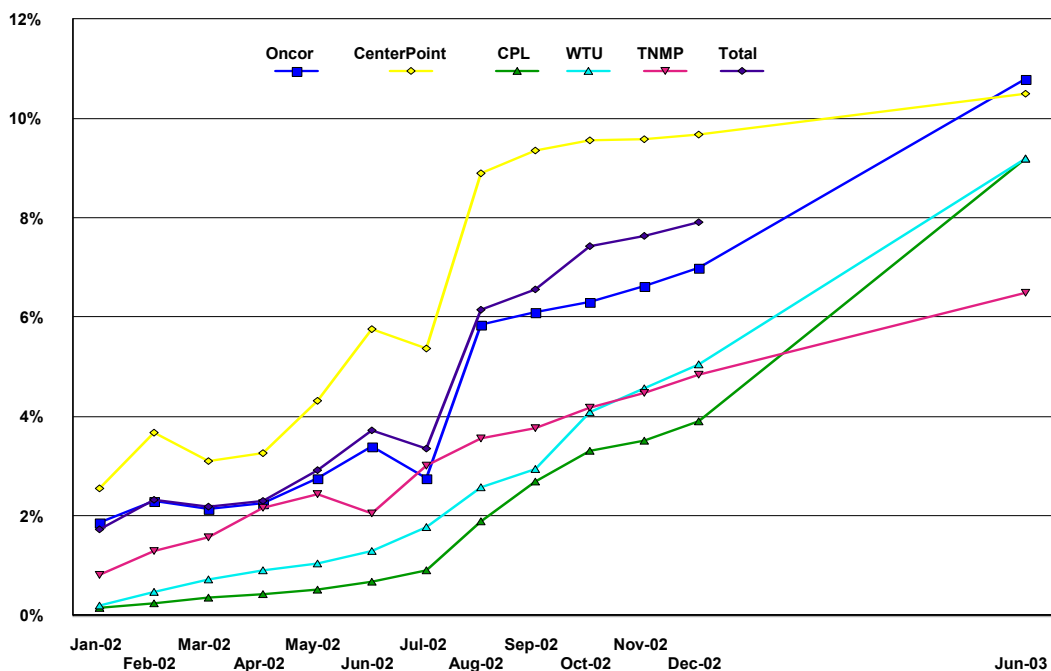


Figure VI.5. Percent of Residential Customers Served by Competitive REP, January 2002 to June 2003.

million MWh) used by secondary voltage level customers were supplied by non-affiliated REPs.

Over 18 percent of commercial and industrial customers taking service at primary or transmission voltage levels (larger commercial and industrial customers, many of which are not-eligible for the price-to-beat) were receiving service from a non-affiliated REP in December 2002 (Figure VI.7). In September, approximately 50 percent of the MWhs (1.7 million MWh) used by these customers were served by REPs not affiliated with the TDU in the customer's area. (The Commission does not report a break down by TDU area because of concern for confidentiality of market share information for these customers by the affiliated REPs. They note that the trends are similar across TDU areas with respect to the number of customers that are being served by non-affiliated REPs.)

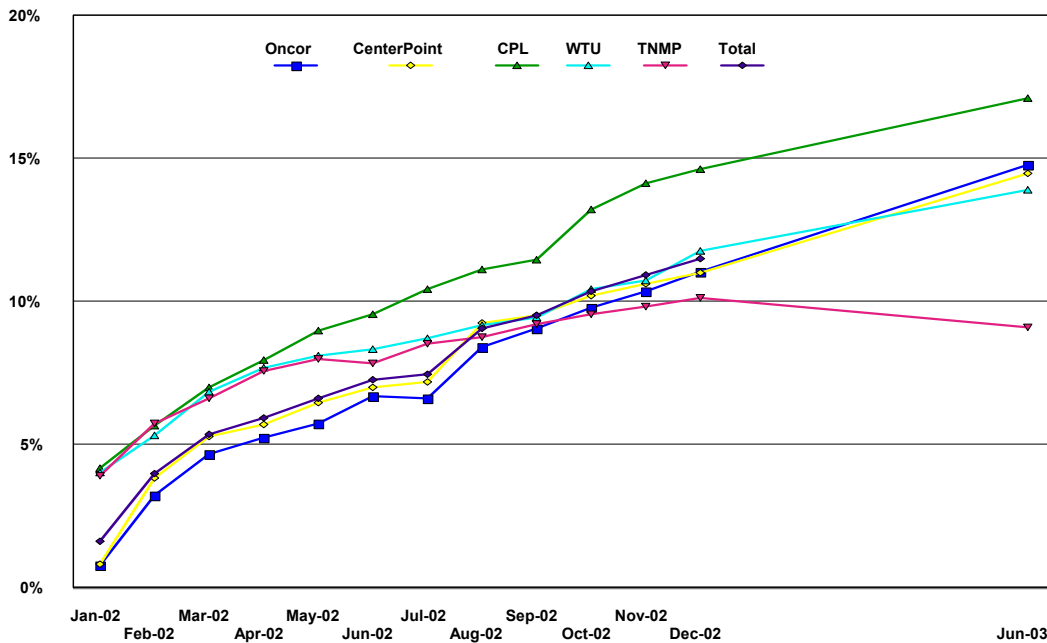


Figure VI.6. Percent of Secondary Voltage Customers Served by Competitive REP, January 2002 to June 2003.

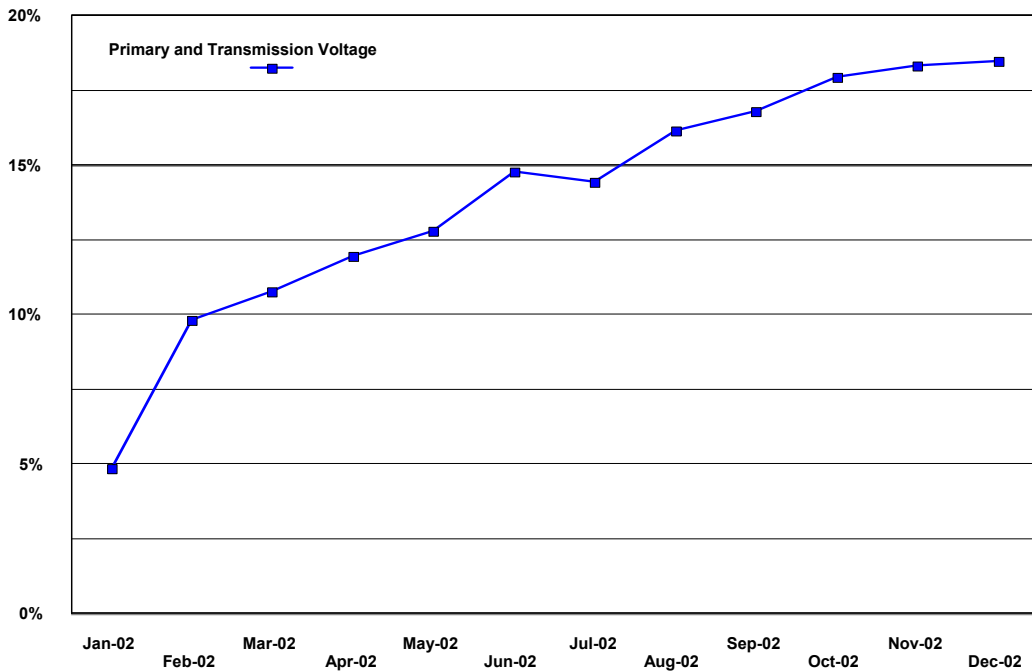


Figure VI.7. Percent of primary and transmission voltage customers served by competitive REP, January to December 2002.

The Commission reported that as of the end of September 2002, 400,837 individual customer premises were being served by a REP other than the incumbent affiliated REP in their service area. This was approximately 6.8 percent of all customers in areas of the state open to retail access. Of these premises, the Commission reported that 319,297 (80%) are residential customers, 71,691 (18%) are commercial and/or industrial customers that take service at the secondary voltage level (predominately smaller commercial customers eligible for the price-to-beat), and 1,322 (less than 1%) are larger commercial and industrial customers taking service at the primary and transmission voltage level and the remaining are lighting accounts.

The Commission also reports that a total of 6,070,477 megawatt hours (MWhs) were served by non-affiliated REPs in September 2002, approximately 25% of the total MWhs sold in the month. Commercial and industrial customers

represent almost 20 percent of the customers who have switched, but they account for over 90 percent of the megawatt hours served by non-affiliated REPs in areas open to competition.

In September 2002, 69,424 residential customers (about 0.8%) were served by the POLR. However, these customers are included in the switching totals by the Commission, even though many of these customers were transferred to the POLR. This overstates the number of customers that chose to switch to another REP and is different than the method used by other states that report customer switching. Using the Commission's figures for September 2002 and adjusting for the inclusion of these POLR customers reduces the percent of residential customers from six percent to 4.7 percent.⁶ As Figure VI.3 shows, the percent of all residential customers reported by December 2002 had reached almost eight percent. Since the number of POLR customers was not reported by the Commission for December, the adjustment for the month was not made.

Figure VI.8 show that as of May 2003, between 25 percent and 39 percent of load was served by non-incumbent or independent REPs. The highest percentage was for AEP Texas North's service area at 39 percent of the load from non-affiliated REPs and the second highest percentage was 36 percent of CenterPoint's load served by non-affiliated REPs. Affiliated REPs are often active in other service territories, however since the Commission does not report individual company market shares, it is not made public how successful affiliated REPs have been in other service areas. The lowest service area market share served by non-affiliated REPs was Oncor's (TXU), at 25 percent of the load served.

⁶Six percent of 319,297 customers works out to 5,321,616.6 total residential customers. Subtracting the POLR customers that were reported to have switched (319,297 - 69,424), leaves 249,873. Then, 249,873 divided by 5,321,616.6 comes to 4.7 percent.

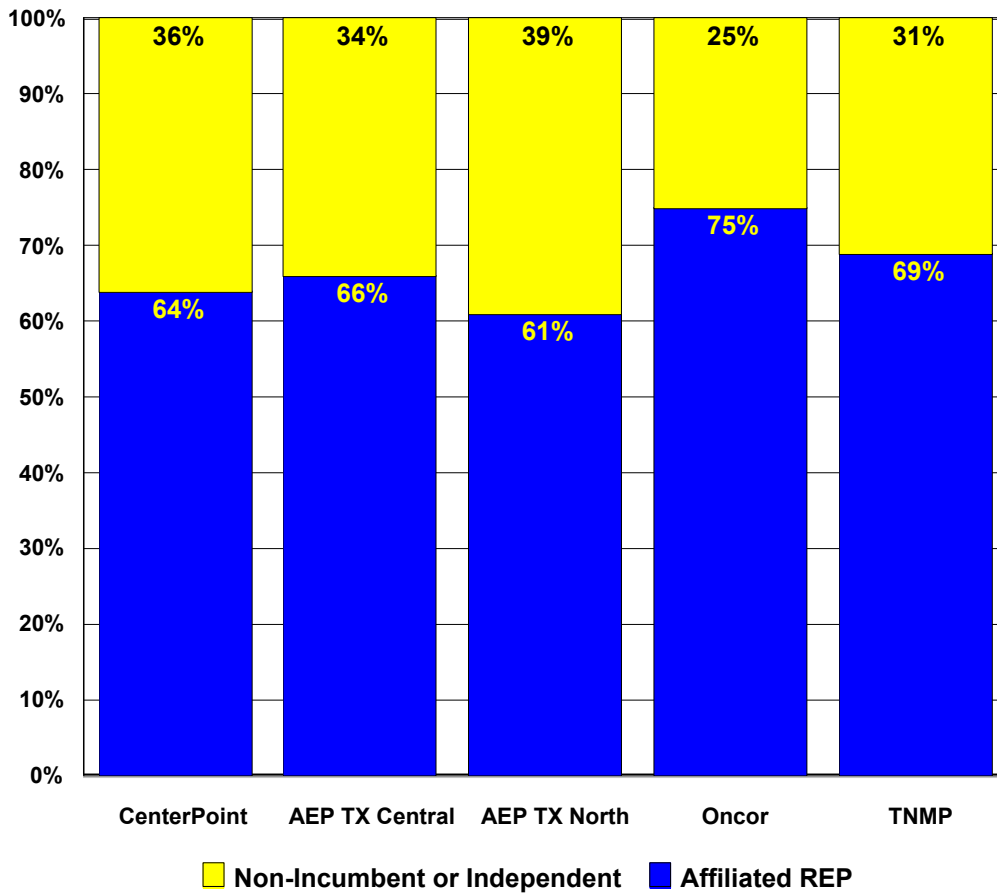


Figure VI.8. Affiliated and non-affiliated REPs’ market shares by service area, percent of load (May 2003).
 Source: Commissioner Brett A. Perlman presentation, “Setting a New Agenda for the Restructured Electric Industry,” August 8, 2003.

Customers without a price-to-beat available from the affiliated REP, are essentially in the market and were encouraged to choose to purchase power from the affiliated REP or a competitive REP. As seen nationally, because these customers use large amounts of power and have a strong incentive to consider alternatives, they are usually the most active shopping group and are usually the more sought after customers by retail suppliers. In addition, the Texas Commission required affiliated REPs to give the non-price-to-beat

customers advance notice of the rate they would be charged on January 1, 2002, if they did not negotiate other arrangements with the affiliated REP or switch to a competitive REP. The Commission reports that the default offers of the affiliated REP were generally either a very high fixed price offer or a pass-through of market prices, both of which may be considered risky options for most retail customers. This likely provided added incentive for these customers to shop for the best available price, since the default offers may lead to rates higher than those in effect before retail access began. As of December 2002, approximately eight percent of the non-price-to-beat customers remained on this default pricing offer, or approximately 92 percent of these customers have negotiated a competitive contract with either the affiliated REP or a non-affiliated REP.

Customer savings

The Commission reports that because of a combination of excess generation capacity, lower natural gas prices, and implementation of the price-to-beat rate reduction mandated by restructuring law, retail customers in Texas paid significantly less for electricity in 2002 when compared to the regulated rates in effect in 2001. The Commission calculates the total annual savings for residential customers at approximately \$900 million in 2002 as compared to what they paid in 2001. Low-income residential customers have received an additional \$68 million in discounts, or an average reduction of \$136 per customer, through the end of October 2002.

They also estimate that through August of 2002, commercial customers have saved, in total, approximately \$420 million compared to rates in effect in 2001 and industrial customers appear to have saved at least \$225 million compared to rates in effect in 2001. They note that many of these customers, especially cities and other government entities, have done this through aggregating with other customers.

The residential customers' savings of approximately \$900 million are based on the price-to-beat rates in effect on January 1, 2002, when the savings ranged from eight percent to 18 percent⁷ compared to the rates in effect on December 31, 2001 (see Table VI.1 and Figure VI.3). They note that approximately \$225 million of this reduction is related to the statutorily mandated six percent reduction in rates and \$675 million of this reduction is attributable to reductions in fuel costs and the expiration of fuel surcharges. These two factors alone, therefore, account for all the \$900 million savings. In addition, as can be seen also in Table VI.1, the price-to-beat rates were *higher* for three affiliated REPs in June 2003, by 14.1 percent for CPL/AEP Texas Central, 13.6 percent for WTU/AEP Texas North, and 0.3 percent for TXU. The other two affiliated REPs had much more modest decreases from the December 31, 2001 rate than the January 1, 2002 price-to-beat rate, 4.4 percent for First Choice/TNMP and 2.9 percent for Reliant/CenterPoint. It should be noted also, as can be seen in Figure VI.3, that all the December 31, 2001 rates (the basis of comparison) were considerably above the January 1999, rates that were likely in effect when the restructuring law passed in May of that same year. All the price-to-beat rates remained substantially higher in June 2003 than the January 1999 regulated rates.

As shown in Table VI.3, residential customers have savings opportunities in all areas open to retail access, ranging between eight percent and 24 percent in June 2003. If the price-to-beat rate increases from the beginning of competition on January 1, 2002 through June 2003 are compared with the percentage savings of the lowest-priced offers to residential customers by area, no offer offsets the increase over that period. Thus, a similar calculation of rate impact for that period would show that customers had paid more since

⁷By company, the reduction in rates from December 31, 2001 to the price-to-beat on January 1, 2002 was 14.7 percent for TXU, 17.1 percent for Reliant/CenterPoint, 18.1 percent for First Choice/TNMP, eight percent for CPL/AEP Texas Central, and 11 percent for WTU/AEP Texas North.

competition began. It is likely, however, that rates would have gone up under regulation as well, due to likely fuel cost adjustments. A comparison, therefore, of the percent increase in the price-to-beat to best offer is not a fair assessment of competition in Texas, only a reminder that the rate changes are substantially the result of fuel price changes and any increase or decrease should not be attributed to just retail access. Table VI.4 compares the percent increase in the price-to-beat since January 2002 and the percent savings on the best offer to residential customers in the area in 2003.

Table VI.4. Percentage increase in the price-to-beat since January 2002 and the percent saving on the best offer to residential customers in June 2003.

Affiliated REP	Increase in the Price-to-Beat from Jan. 2002 to June 2003	Savings on Lowest Priced Offer to Residential Customers, June 2003
TXU	17.6%	13%
Reliant/CenterPoint	17.2%	16%
First Choice/TNMP	16.6%	8%
CPL/AEP Texas Central	24.1%	21%
WTU/AEP Texas North	27.7%	24%

Other Issues

Stranded Cost True-Up

Utilities are required to finalize their stranded cost determination in 2004 through a market valuation of assets. The Commission is concerned that because of the current level of uncertainty and the lack of investor interest in

wholesale generation companies, the market-based valuations of generation facilities or companies that own them may result in significant stranded costs for several companies. High stranded costs would, in turn, likely result in higher delivery charges from the TDUs. In Texas (as in many other states), the Commission noted that stranded costs are predominately related to nuclear generation assets' high capital costs.

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

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

TXU and Entergy have both agreed to forego further stranded cost recovery, and will not be conducting true-up proceedings as a result of these settlements. Reliant, TNMP, and CPL are required, barring additional settlements, to finalize their stranded costs.

The rule amendments included a "transmission cost recovery factor," or TCRF, that permits a utility to receive expedited cost recovery of additional transmission investments, and include those costs in the non-bypassable rates that are charged to retail customers. The TCRF is to only recover the capital costs associated with new investments in transmission facilities, and is subject

to reconciliation in the transmission utility's next transmission rate case. The Commission believes that the TCRF mechanism will encourage the timely construction of new transmission facilities needed to facilitate competition by reducing the risk to the transmission utility of making such investments. (This is similar to a FERC proposal issued in January of 2003.)

Capacity Auction

The Commission's rule on capacity auctions is intended to promote competition in the wholesale market by increasing the availability of generation and liquidity by requiring affiliated PGCs to sell entitlements to at least 15 percent of their Texas generation capacity. In compliance with the Commission's rule, monthly and annual generation capacity auctions have been conducted by incumbent utilities.

Market Monitoring

The Commission created a Retail Market Oversight Section in the Electric Division to coordinate monitoring of retail electric market issues. The responsibilities of the section include the monitoring of the day-to-day operation of the retail market in Texas, including monitoring the success of processing switch requests, move-in/move-out transactions, the exchange of meter data needed to bill retail customers, and billing issues that affect retail customers. This section also monitors compliance with Commission rules, transmission and distribution tariffs and the ERCOT Protocols, and participates in retail market design and implementation activities at ERCOT. This section also participates in the development of retail market protocols for the areas outside of ERCOT, and oversees the administration of the system benefit fund and low-income discount programs.

The Commission also has the Market Oversight Division (MOD) that has responsibilities that include monitoring the activities of wholesale market participants to ensure compliance with Commission rules and the ERCOT

Protocols and to prevent the exercise of market power and other anti-competitive behavior. MOD investigates market activities as necessary, and participates in market design and implementation activities at ERCOT to eliminate market design flaws as they are recognized. MOD staffing currently consists of nine full-time employees and graduate student interns in the Economics and Engineering programs at the University of Texas at Austin. MOD compiled a comparison of the market oversight staffs in the five operating competitive electric markets in the United States, and is reproduced in Table VI.5.

Table VI.5. Comparison of market monitoring staffing and budgeting.

Market Region	Market Size (Peak Demand, MWs)	2002 Full Time Equivalents	2003 Full Time Equivalents	2002 Budget (millions of dollars)
California ISO	43,000	14	16	3.0
New England ISO	26,000	11	14	1.9
New York ISO	32,000	21	30	4.8
PJM	54,000	12	NA	2.7
ERCOT	58,000	9	NA	0.6

Source: Public Utility Commission of Texas, January 2003, p. 52.

PUCT Table Notes: 2002 budget figures are estimates provided by each ISO and include the costs of consulting services. Figures for New York include resources for legal enforcement. New York indicated that their budget for 2003 will be increased to \$6.5 million.

SECTION VII West and California

In the previous two reports, details and analysis of the Western and California wholesale market crisis were examined. Some of those studies that were summarized are reproduced below along with some updated prices and findings from the California ISO.

The western power crisis began in late May of 2000 when the average California 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 declared by the California ISO to occur in that train of events can be viewed as the end of the crisis period, in early July of 2001. 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 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.¹

Figure VII.1 graphs monthly average prices from January 2000 through December 2002. This graph shows the full span of time of the price run-up in California and the relative calm in average monthly prices through the end of 2002. Figure VII.2 charts the daily western hub prices from June 2002 to June 2003. As seen in other

¹A 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.)

power markets, the effect of the natural gas price spike in early 2003 can be seen, albeit, even more pronounced than other power markets. Also, the effect of warm weather in May in the West and in early June can also clearly be seen.

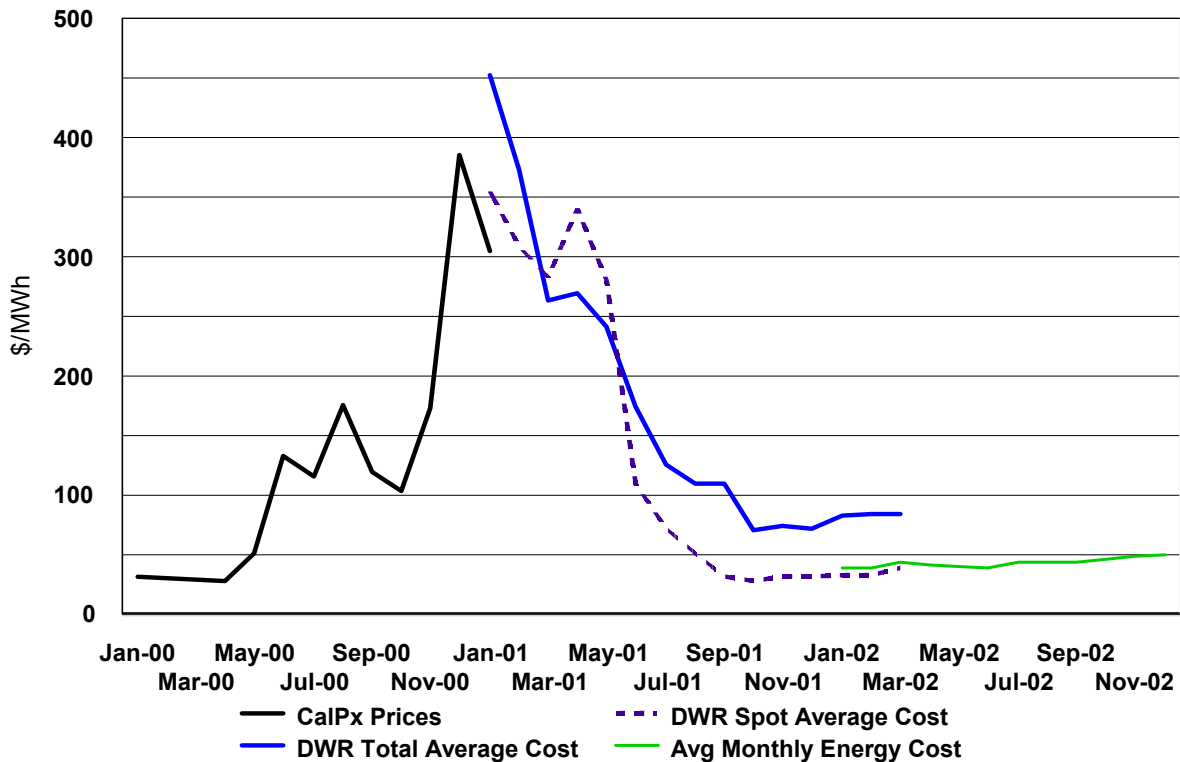


Figure VII.1. California power prices from January 2000 through 2002. Sources: The California Power Exchange, California Department of Water Resources, and California ISO.

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 run-up. It would be expected that the price would be

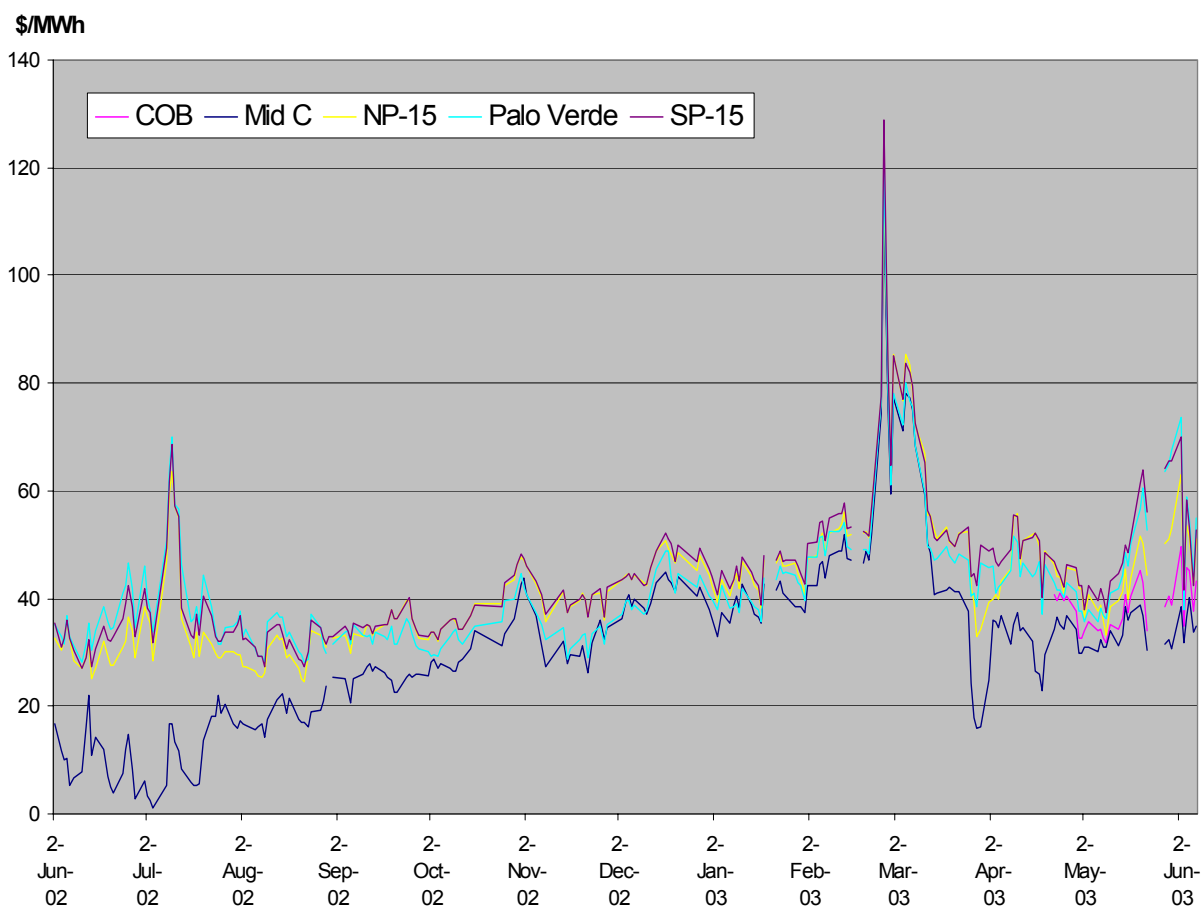


Figure VII.2. Western wholesale power hub prices.
 Source: IntercontinentalExchange, Inc., www.intcx.com.

driven up to the marginal cost of the highest cost marginal unit needed to satisfy demand—a higher marginal cost than would be obtained 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 analyses of California’s markets.

Before the Western power crisis of 2000 and 2001 began, a study by Borenstein, Bushnell, and Wolak² 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 determined to be \$795 million.³ 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.⁴ 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

²Borenstein, 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.

³As 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.

⁴Anjali 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.

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.

An analysis by Joskow and Kahn,⁵ 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 \$62.60 per MWh for June 2000 (assuming a NOx price of \$10/lb), which compares with the average PX price for the month of \$120.20 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 \$121.50 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.

⁵Joskow 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.

Borenstein, Bushnell, and Wolak⁶ estimated the monthly Lerner index for California from June 1998 through October 2000. These estimates are shown in Figure VII.3. 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 pre-restructuring generation) to have low energy prices—and thereby increase their competition transition charges or CTCs (as previously explained in footnote 3 of this section). In general, the Index spikes during the summer and early fall months when demand is at its peak and supplies are most constrained. They also correlated the hourly demand level for electricity with the corresponding Lerner Index for that hour,⁷ as shown in Figure VII.4. 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 market is concentrated as it was 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.

⁶Severin 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.

⁷They used "kernel" regression to determine the curves for each year.

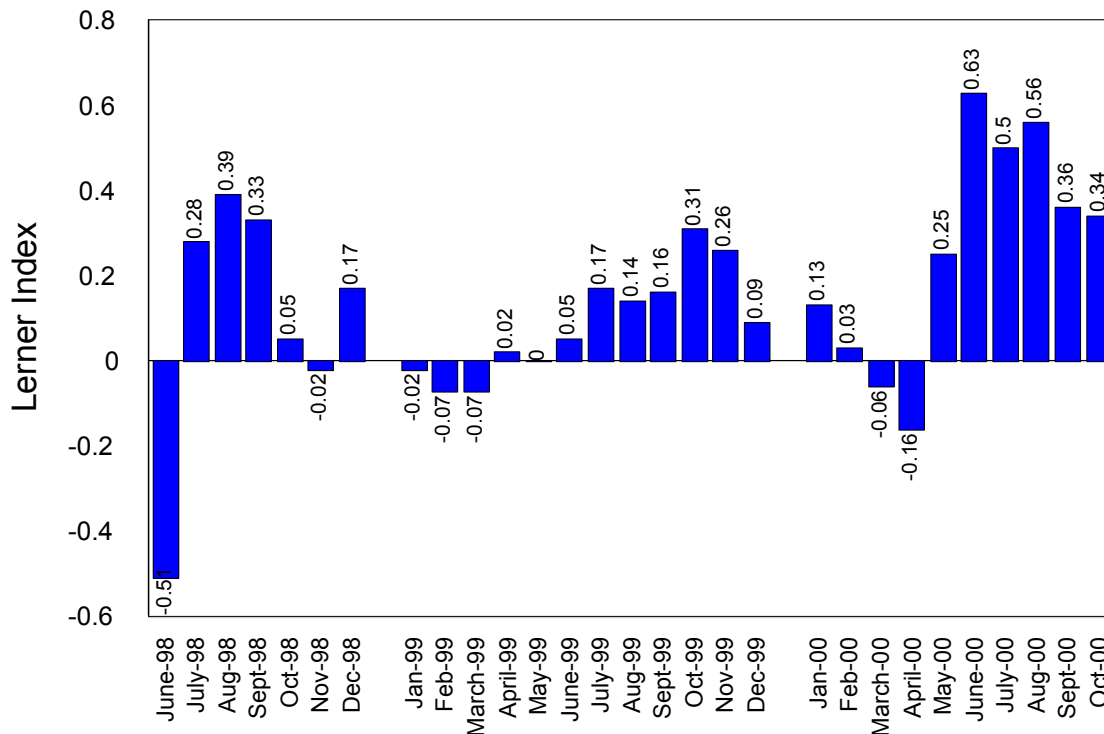


Figure VII.3. California monthly Lerner Index for June 1998 through October 2000. Source: Borenstein, Bushnell, and Wolak, “Measuring Market Inefficiencies in California’s Restructured Wholesale Electricity Market,” June 2002.

Borenstein, Bushnell, and Wolak also estimated supplier economic rents⁸ 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 and more than eleven times the 1999 estimate of \$382 million, to \$4.45 billion in 2000. 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.

⁸Economic 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.

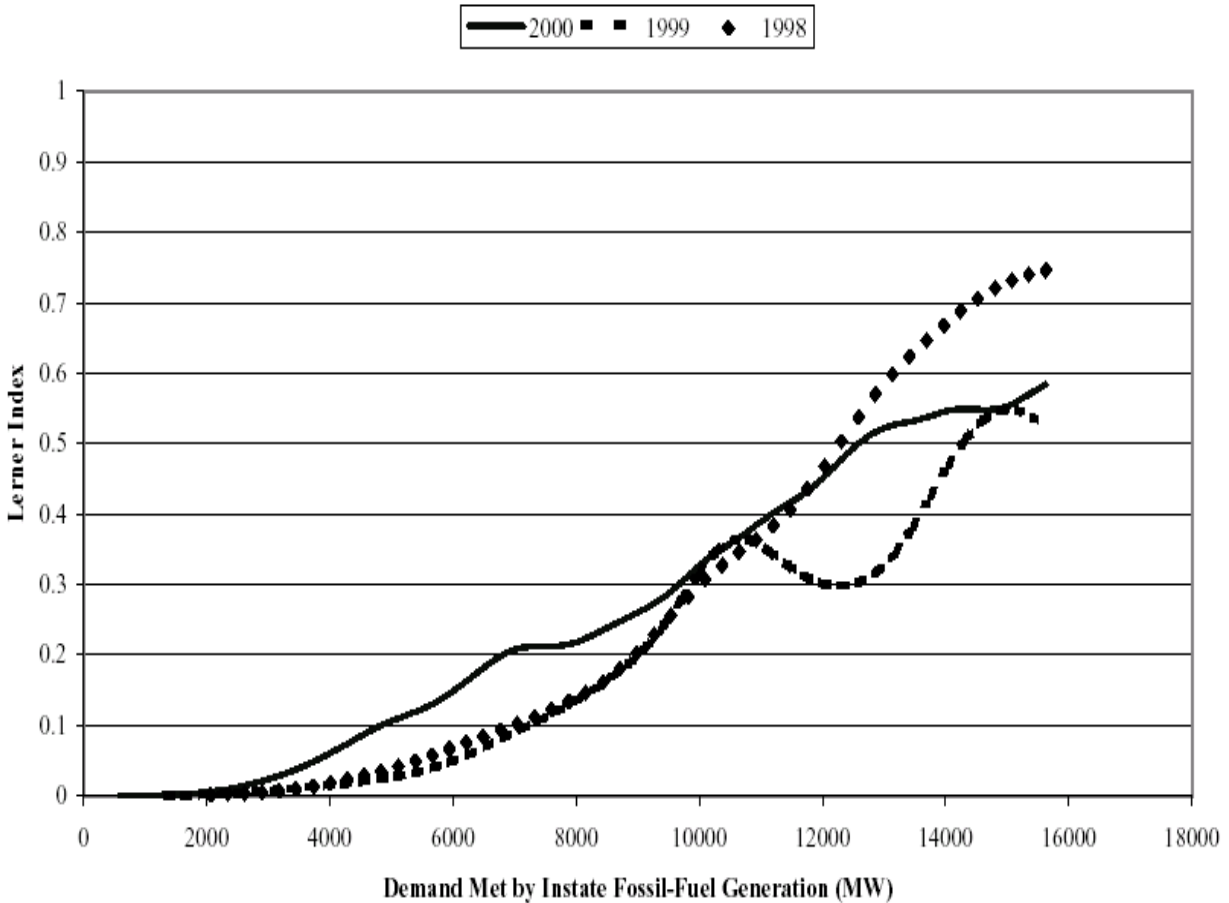


Figure VII.4. The relationship between the level of demand and the Lerner Index (market power markup estimate) for California.
 Source: Borenstein, Bushnell, and Wolak, "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market," June 2002.

An analysis by the California ISO⁹ also shows that electricity suppliers in California exercised significant market power and were able to raise prices significantly above competitive levels. Figure VII.5 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

⁹California Independent System Operator, "Third Annual Report on Market Issues and Performance: Market Monitoring, Investigative, and Compliance Activities," January – December 2001, January 2002.

ISO's 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 VII.6. 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.

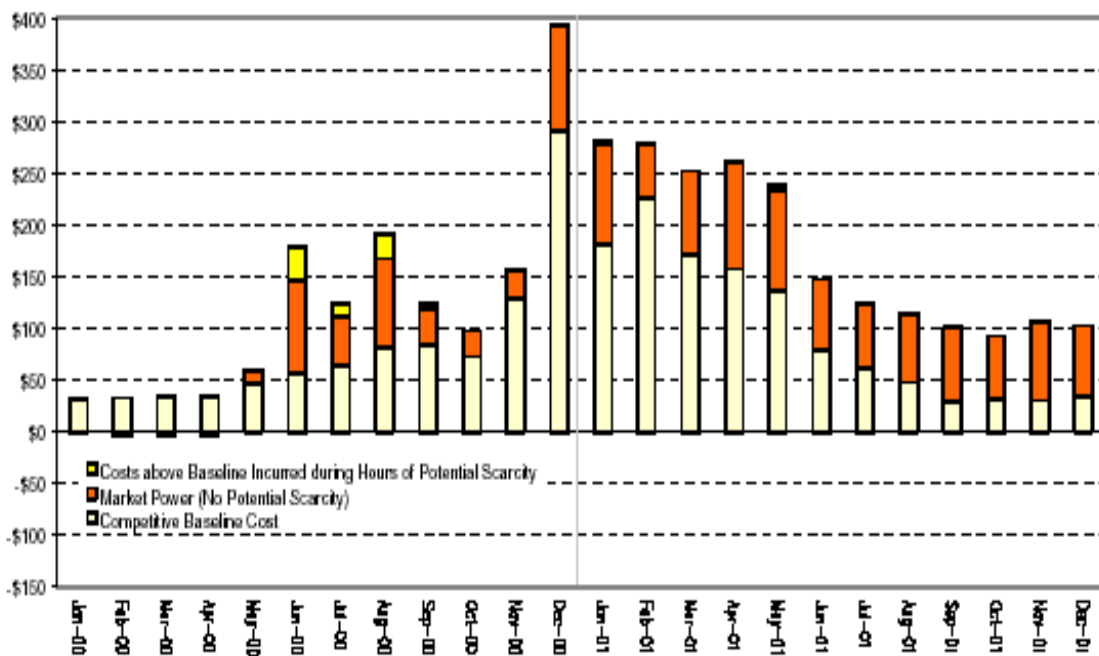


Figure VII.5. Price-cost markup of forward and real-time energy.
 Source: California Independent System Operator, "Third Annual Report on Market Issues and Performance Market Monitoring, Investigative, and Compliance Activities," January – December 2001, January 2002.

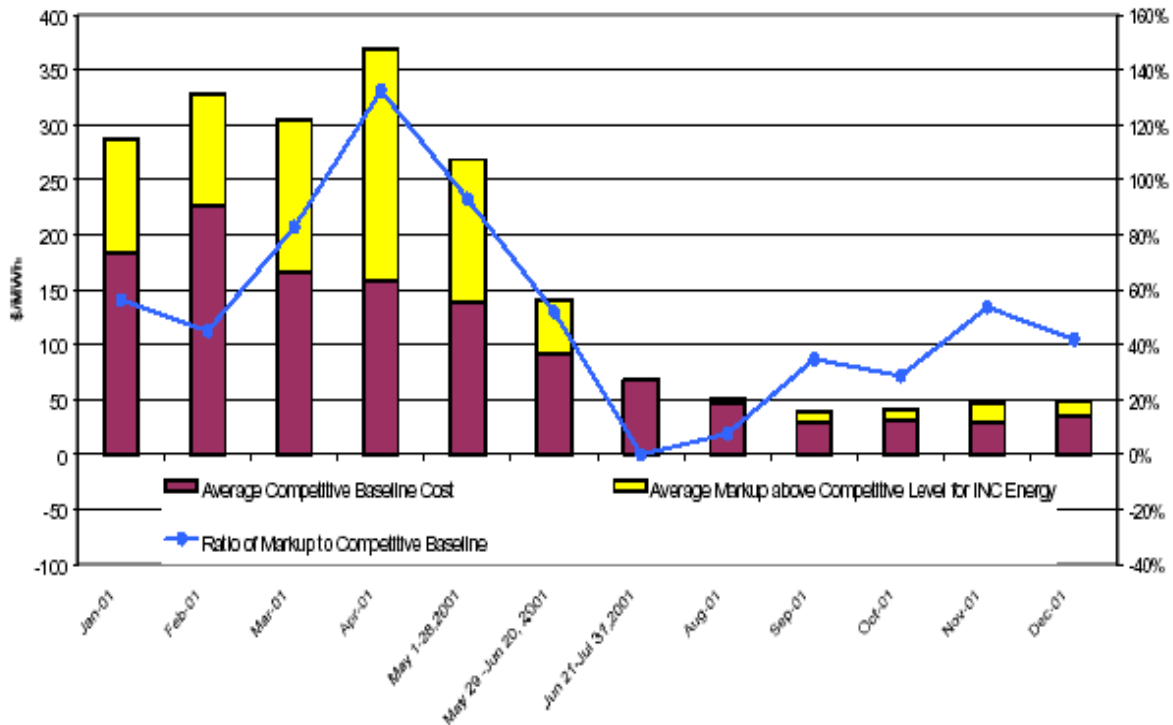


Figure VII.6. Price-cost markup in the real-time energy market. Source: California Independent System Operator, "Third Annual Report on Market Issues and Performance Market Monitoring, Investigative, and Compliance Activities," January – December 2001, January 2002.

In its 2002 Annual Report,¹⁰ California ISO estimates that the 2002 average markup was \$5.69 per MWh or 17 percent above costs. They note that the markup approached 35 percent in the summer months (May and July from the graph). Figure VII.7 shows the California ISO's monthly markup estimates for 2002. The California ISO also began estimating a volume-weighted, twelve-month rolling average of short-term markups, or the "twelve month competitiveness index." The intent is to measure the degree of market power during the market's transition to a new structure—of adequate supply and demand response. The 2002 index is reproduced as Figure VII.8

¹⁰California Independent System Operator, "2002 Annual Report On Market Issues and Performance," April 2003.

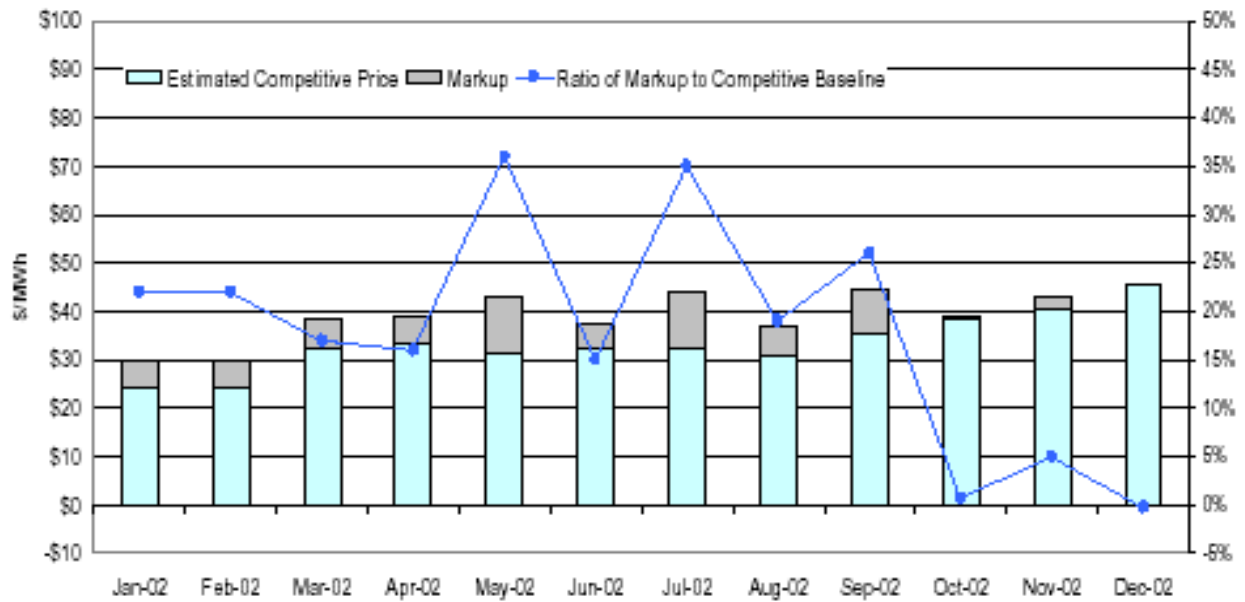


Figure VII.7. Price-to-cost markup in short-term energy market in 2002.
Source: California ISO, April 2003.

below. Since the ISO estimates that the index was above \$5 per MWh for each month in 2002 and peaked at nearly \$51 per MWh, they then conclude that during 2002 “some market power persists in the short-term market.”¹¹ They assume that the market is “workably” competitive if the index is below \$5 per MWh.

¹¹California ISO, “Annual Report,” p. 3-15.

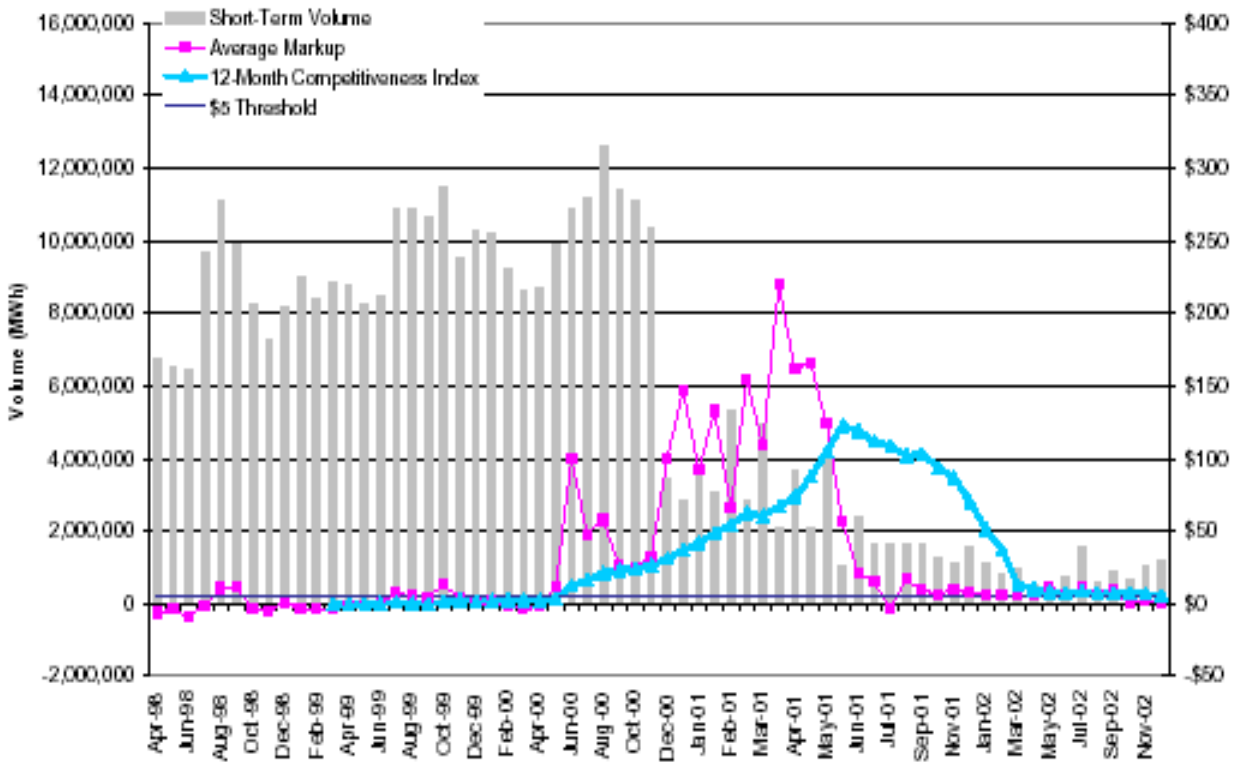


Figure VII.8. California ISO's Twelve-Month Competitiveness Index, April 1998 through December 2002.

Source: California ISO, "Annual Report," p. 3-15.

Biography

Dr. Rose has been working on energy and regulatory issues for more than nineteen 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 Senior Fellow at the Institute of Public Utilities at Michigan State University and lectures for the School of Public Policy and Management at The Ohio State University. Dr. Rose was a Senior Institute Economist at The National Regulatory Research Institute at Ohio State University from 1989 until October 2002. Prior to NRRI, Dr. Rose worked on many energy related issues at Argonne National Laboratory from 1984 to 1989. Dr. Rose received his B.S. (1981), M.A. (1983), and Ph.D. (1988) in Economics from the University of Illinois at Chicago.