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STATE OF THE MARKETS REPORT

STAFF REPORT BY THE

OFFICE OF MARKET OVERSIGHT AND INVESTIGATIONS

FEDERAL ENERGY REGULATORY COMMISSION

State of the Markets Report

Assessment of energy markets for the period
January 1, 2002 through June 30, 2003

Staff Report by the
Office of Market Oversight and Investigations

Federal Energy Regulatory Commission

January 2004

Docket MO4-2-000

Preface

This is the Federal Energy Regulatory Commission's second State of the Markets Report and the first prepared by the Office of Market Oversight and Investigations (OMOI). The report covers an assessment period from January 2002 through June 2003 and covers electricity, natural gas and related financial market conditions and trends. In contrast to OMOI's seasonal assessments, which focus on the near future, this report examines market performance in the recent past. In the State of the Markets Report, OMOI presents findings regarding market conditions relevant to the Commission and identifies emerging policy issues that may soon require the Commission's attention.

The Commission created OMOI in April 2002 to focus its efforts on energy market oversight. Any errors in this report are the responsibility of OMOI alone and not of the Commission as a whole.

I want to commend the able leadership team for this project: Mary Beth Tighe and Cynthia Wilson. Other members of this team are listed in the Acknowledgements.

We encourage readers to provide feedback on this OMOI product by filling out the State of the Markets Report Evaluation Card below, sending comments to an e-mail address specifically set up for this report, SOM.2003@FERC.gov, or by contacting staff referenced in the acknowledgements at:

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Washington, D.C. 20426
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A fair energy marketplace is everyone's responsibility. Please do your part. If you encounter inappropriate energy market behavior, contact our ENFORCEMENT HOTLINE toll-free by telephone at 1-888-889-8030 or via e-mail at Hotline@FERC.gov.

Thank you.

William F. Hederman

Director

Office of Market Oversight and Investigations

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INTRODUCTION

The Federal Energy Regulatory Commission (FERC) regulates the transmission and sale of natural gas and electricity for resale in interstate commerce to ensure that customers have dependable, affordable energy through competitive markets. One of the Commission's strategic goals is to protect customers and market participants through vigilant and fair oversight of energy markets in transition. To pursue this goal, the Commission promotes understanding of energy market operations and assesses market conditions using objective benchmarks in order to create pro-competitive market structure and operations.

The purpose of this State of the Markets Report, produced by FERC's Office of Market Oversight and Investigations (OMOI), is to assess the competitive performance and efficiency of U.S. wholesale natural gas and electricity markets from Jan. 1, 2002, through June 30, 2003 (the "assessment period"). This report fulfills the Commission's commitment to Congress to provide a comprehensive assessment of energy markets that uses market data and performance criteria, improving the Commission's ability to identify and correct trouble spots in the market before they become serious. This report also establishes a framework for performing future analyses of energy markets in order to better assess performance and improvements over time.

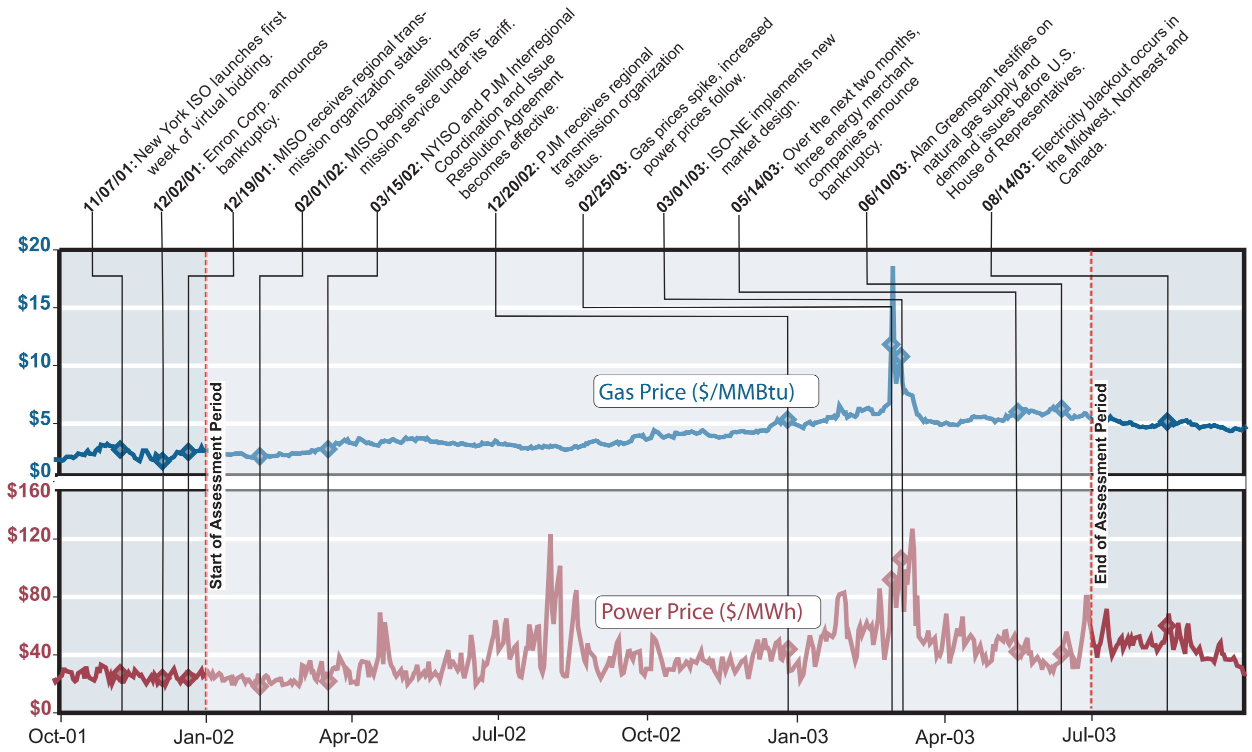
Summary

Marginal improvements occurred in the way wholesale energy markets in the United States provided electricity and natural gas during the assessment period, despite significant challenges. Markets delivered energy reliably and several improvements occurred, including improvements in the functions of certain short-term, organized electric markets; the development of innovative products and services designed to improve risk management; price stabilization in the West due to increased generation capacity and improved hydroelectric conditions; investment that added new generating capacity throughout the country (increasing total U.S. capacity by 10 percent), including new efficient generation in the Southeast; and a focus by a broad set of market participants on the credibility of price formation.

As shown in Figure 1, energy markets faced serious challenges that included an unprecedented financial downturn for energy traders and providers and a corresponding decline in the use of risk management tools, mixed incentives for energy investment, the slow response of natural gas production to increasing prices, the continuing thinness of reported market activity and the expansion of concerns about the transparency and credibility of price formation. However, energy markets proved sufficiently resilient to manage these challenges and delivered energy to customers reliably.

Across the country, prices for both electricity and natural gas were below 2001 levels but tended to rise during the assessment period, more significantly for natural gas than electricity. Downward pressure on electric prices early in the assessment period resulted from the entry of new generating capacity and lower demand levels than earlier, comparable periods. Electricity price increases appear largely attributable to increases in natural gas prices.

Figure 1: Market events challenge natural gas/power market liquidity and credibility.



Note: *Gas Daily* daily spot prices at Henry Hub provided to illustrate two years of U.S. gas commodity price behavior starting in winter 2001–02. An average of peak hour prices in PJM's day-ahead market provided as an example of regional power prices.
Source: PJM, Platts *Gas Daily* and trade press. Graphic by OMOI.

Approach

More than a decade ago, the Commission began to make use of competitive market forces to the extent possible to benefit customers and to achieve just and reasonable prices.[1] Well-functioning competitive markets benefit customers because they:

- provide information about the value of energy to buyers and sellers active in the markets who, through their market actions, produce competitive prices,
- create incentives for efficient production,
- allocate scarce resources efficiently,
- create incentives for efficient investment where and when needed by highlighting scarcity through price signals, and
- provide customers with new options and flexibility for meeting demand.

To the extent that markets do not function adequately, the benefits of competition are not achieved for customers.

To function adequately, wholesale markets need to be workably competitive and need to offer sufficient contracting alternatives to allow participating firms to manage their risk. Workably competitive markets tend to have many buyers and sellers participating, have no artificial barriers to entry and exhibit little market power or manipulation.

[1] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, Regs. Preambles 1982-1985, FERC Stats. & Regs. ¶ 30,665, order on reh'g., Order No. 436-A, Regs. Preambles 1982-1985, FERC Stats. & Regs. ¶ 30,675 (1985).
Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636, FERC Stats. & Regs. ¶ 30,939 (1992).
Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1977), FERC Stats. & Regs. ¶ 31,048 (1997).
Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. ¶ 30,092 (2000), aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

Prices in competitive markets tend to respond to fundamental changes in supply and demand. For this reason, we expect efficient competitive natural gas and electric markets to exhibit market prices that respond to factors affecting demand such as economic growth and weather, and to factors affecting supply such as input prices, production levels and transmission congestion. In addition, prices in well-functioning markets are sufficiently transparent for market participants to base buy and sell decisions, and to signal the need for new investment. Sufficiently robust markets show evidence of alternative products that allow firms to balance reliance on short-term spot markets with less volatile longer-term markets, or to protect themselves from volatility through investment or the purchase of risk management or hedging vehicles. We would expect the prices for these alternative products to converge to a point that reflects differences in risk among them. If a price differential exists for other reasons, customers in a well-functioning market will seek out the best value, putting competitive pressure on the prices of all products.

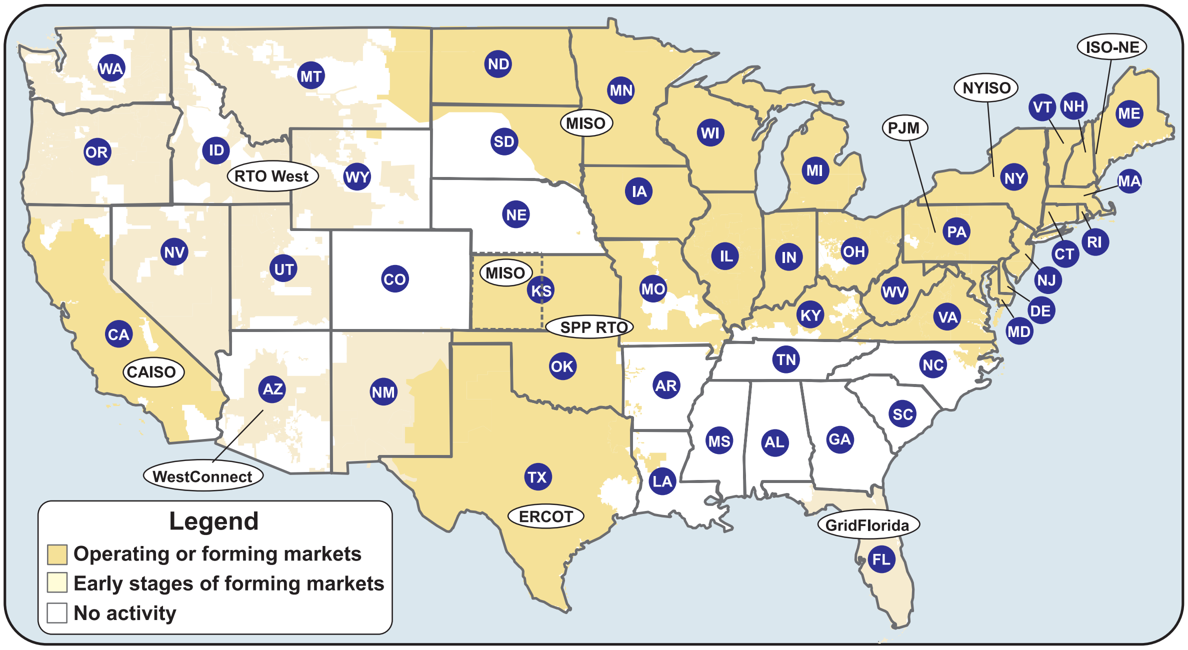
Using these characteristics of well-functioning markets as a guide, this report assesses how well energy markets within the oversight of the Commission, or those closely related to those jurisdictional markets, functioned during the assessment period. In order to determine whether natural gas and electricity markets functioned in accordance with these factors, OMOI staff examined available evidence on several factors.

First, we examined key characteristics of the structure of the markets and assessed their ability to support competitive performance. Staff then compared price behavior during the period to fundamental supply and demand drivers of prices, including seasonal demand, peak delivery constraints, storage levels, known outages, generating fuel prices and others. In particular, staff reviewed prices during scarcity conditions at certain times and locations. Staff examined where and how regulatory mitigation of market outcomes, designed to deal with perceived market imperfections, was administered during the period. Staff also reviewed market design and transparency, assessing the availability of information and the degree to which differences in market designs across regions or industries inhibit efficient commerce. Staff assessed risk management options across markets, looking at both the availability and use of these price and reliability hedging tools. Finally, staff examined investment during the period, assessing actual investments in infrastructure and supply options as well as investment signals in these markets.

Key findings of OMOI's analysis are presented first. The remainder of the report is organized into two major sections, one examining wholesale electric markets and one examining wholesale natural gas markets. Electricity markets are analyzed regionally and divided into two groups: regions with organized electricity markets—markets operated by independent system operators (ISOs) or regional transmission organizations (RTOs)—and regions without organized electricity markets operating during the assessment period. Figure 2 characterizes the level of development of regional transmission service and electricity markets across the country. Approximately 120 million Americans (40 percent of the population)[2] lived in states served by organized markets during the assessment period. An additional quarter of the population lives in regions where organized markets are forming and will be operated by MISO, SPP and an expanded PJM.

[2] Derived from U.S. Census Bureau (factfinder.census.gov).

Figure 2: Operating or forming organized electricity markets serve approximately 70 percent of U.S. population.



Note: Western Kansas, which is part of the NERC SPP region, will be operated by MISO.
Source: Platts POWERmap. Graphic by OMOI.

There are five regions with operating organized electricity markets assessed in this report[3]:

- ISO-NE (the New England states)
- NYISO (New York)
- PJM (much of the Mid-Atlantic states)
- ERCOT (most of Texas)
- CAISO (most of California)

There are six regions without operating organized electricity markets assessed in this report:

- Southeast
- Florida
- Midwest
- South Central[4]
- Southwest
- Northwest

[3] For a map of these regions, see Figure 8 and Appendix 1.

[4] During the assessment period, Entergy Corp. was in preliminary stages to join SeTrans, a proposed RTO in the Southeast. For this reason, its service territory was considered as part of the Southeast, not South Central. Depending on future activities, we may realign the regions in subsequent reports.

Key Findings of the Report

Electricity Markets

1. **Electricity markets generally performed consistent with supply and demand factors during the assessment period, with prices rising and falling daily and seasonally in response to factors such as weather, customer demand, input fuel prices and power plant outages.**

The relationship between prices and underlying market fundamental variables is complex, as we observed in the response of electricity markets across the country to the run-up of natural gas prices in late February and early March 2003. With this notable exception, electricity prices during 2002 were lower than in prior periods, but rose to moderately higher levels in the first half of 2003.

Organized markets delivered electricity to customers in 2002 at average regional prices lower than in 2001. Prices declined 8–15 percent, with the exception of CAISO markets, which declined 77 percent from 2001 levels. Milder weather, new generating capacity, inexpensive natural gas and improved hydroelectric conditions in the West contributed to the lower 2002 prices. Prices began to increase with the rise and spike of natural gas prices in late February and early March 2003 and remained at moderately higher levels (20–30 percent higher than in 2001) through mid-2003. Again, CAISO was an exception with first-half 2003 prices nearly 70 percent below 2001 levels. ERCOT was another exception with average first-half 2003 prices more than double the average 2001 level. Prices for bilateral transactions in these regions demonstrated similar trends.

Bilateral prices outside regions with organized markets were reported lower in 2002 than their 2001 levels, trending upward in summer 2002 and during the February/March 2003 natural gas price spike. The average first-half 2003 prices were about 20 percent higher than 2001 levels, with the exception of the western trading hubs of Mid-Columbia and Palo Verde, where prices remained significantly below 2001 levels.

Electricity price volatility generally declined in regions with organized markets, but generally increased in regions without organized markets. In organized markets, the exception was ERCOT, where volatility increased. Volatility of bilateral prices at Mid-Columbia in the Northwest declined in 2003, reflecting improved hydroelectric availability in the region. Electricity price volatility was higher than physical natural gas price volatility, which rose steadily during the period.

Lower prices resulted in losses for some power plants. Investors, not customers, generally bore these losses, which caused some short-term financial stress, but encouraged long-term market efficiency through investment accountability. Despite the exit and entrance of market participants, as well as changes in company strategies and the crisis in confidence during the assessment period, the electricity markets delivered reliable service to customers.

2. **Organized markets offered new risk management tools during the assessment period. Market participants had few opportunities for long-term price discovery, which facilitates risk management.**

Among the most notable developments were the increase in risk management products offered in organized markets and the introduction of additional financial products for risk management. NYISO, ISO-NE, PJM and ERCOT introduced new products and services, such as firm transmission right options. Nymex began to offer new credit clearing products. It also introduced a redesigned PJM futures contract at the end of the assessment period, the use of which rose over time. Risk management tools were available bilaterally in all regions, but heightened creditworthiness risk and associated costs affected their use.

Despite significant reliance on long-term bilateral electricity contracts (approximately one-third of reported U.S. sales are delivered under long-term contracts of one year or longer), it is not clear that market participants used published indices for long-term products (such as *Megawatt Daily*'s prices through calendar year 2006), which could have provided long-term risk management. Anecdotal evidence suggests that parties aggregated their transactions through independent parties to derive long-term forward price curves to help determine value-at-risk for risk management controls and reporting. The PJM Western Hub contract remained the only futures market for electricity.

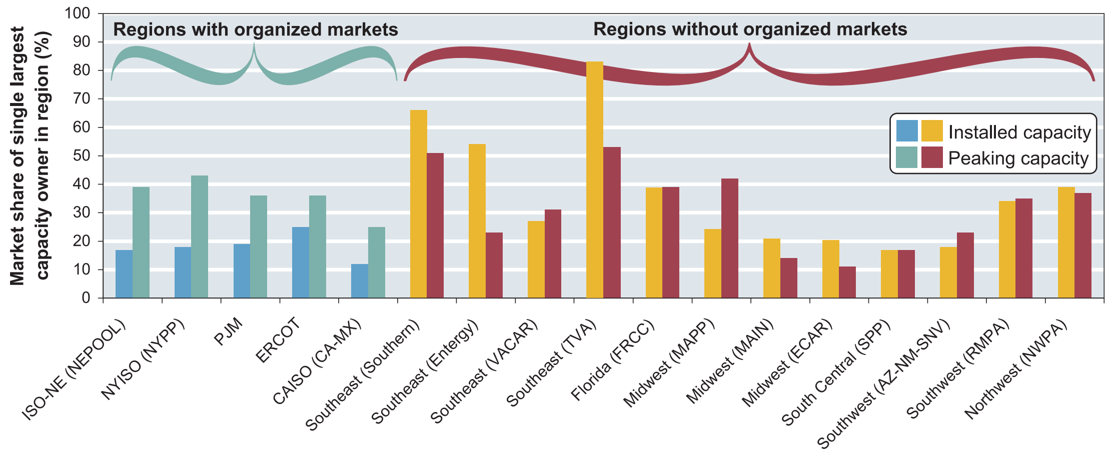
3. **In most regions bilateral trading volumes reported to index publishers and transacted on the IntercontinentalExchange (ICE) declined over the assessment period, coinciding with merchant credit problems. Regions in the West were a notable exception to this trend. Despite overall declines in bilateral trading volumes, organized markets had robust participation during the assessment period.**

The Enron bankruptcy in 2001 and later developments precipitated a crisis of confidence in the physical and financial electricity industry. Many companies engaged in trading withdrew from bilateral markets as the perceived risk and creditworthiness requirements increased significantly. The decline in the number of market participants trading actively led to lower liquidity in bilateral markets, and growing concern regarding the credibility and representativeness of the price data being supplied to index developers. Bilateral trading volumes in the West did not follow this trend, as the region rebounded from a collapse in trading. While overall trading activity fell during the period, new players emerged with financial backing and experience in other markets.

Despite declines in bilateral trading volumes, participation in organized short-term markets was strong. Sales in regions with organized markets were approximately 60 percent of total reported wholesale sales during the assessment period.[5] On average, 67 percent of reported transactions in regions with organized markets were under short-term contracts (bilateral and in ISO-operated markets). With the exception of the California and ERCOT balancing markets, 20 percent or more of short-term transactions in regions with organized markets took place within the ISO or RTO short-term market. This in part reflects the availability of transparent organized short-term markets. It also reflects local supply-demand conditions. Market participants in

[5] Derived from FERC Electric Quarterly Reports (EQR), Fourth Quarter 2002 through Second Quarter 2003. In the EQR, companies report wholesale power sales within FERC's jurisdiction. Generation to serve one's own load, sales by federal authorities such as TVA and BPA, sales occurring fully within ERCOT and sales by qualifying facilities (QFs) under QF contracts are not included. Filings with clear errors affecting total sales were eliminated from the dataset pending correction from the submitting company. Regional allocation of sales was estimated using Point of Delivery Control Area and Specific Location information provided in the filings. All sales to ISOs were assumed to be short-term and to occur within the ISO's control area.

Figure 3: Generation ownership concentration lower in organized markets.



Note: Installed capacity is the measured capacity or the capacity demonstrated to have been available during the hour of highest output of a generating unit. For purposes of this analysis, the working definition of a peaking unit is a natural gas or oil-fired unit with a heat rate greater than 10,000 Btu/kWh or a combustion turbine or internal combustion unit smaller than 50 MW in size with no reliable heat rate information reported.

Source: Platts POWERdat, Modeled Production Costs-Ownership-Based dataset for calendar year 2002. Analysis and graphic by OMOI.

regions without organized markets reported 61 percent of transactions were under short-term bilateral contracts.

4. **Regions with organized markets had numerous buyers and sellers and the ownership of generation was spread among several entities. There were fewer buyers and sellers in most regions without organized markets and the ownership of generation was more concentrated in many of these regions. Concentration reduced competitive forces in some markets.**

The market structures in regions with organized markets were relatively competitive during the assessment period, providing the basic conditions and support for the competitive performance of these markets. Load pockets in these regions were important exceptions to this general result. The market structures in regions without organized markets provided significantly less support for competitive market performance, with control of both generation and transmission service concentrated in a single or a few vertically integrated entities during the assessment period.

Figure 3 shows the single largest installed and peaking capacity owner across regions. OMOI's analysis of concentration of generating plant ownership found that for installed generation in organized markets, no single firm controlled a dominant share of capacity for the overall market. However, during peak periods and in geographically defined areas like load pockets, market shares tended to be higher. Many regions without organized markets exhibited high supplier market shares in both installed and peaking capacity generation. This is largely due to the dominance of vertically integrated utilities that controlled both transmission and generation services, and historical development of the regions.

As a result of these findings, OMOI concludes that there are regions without organized markets where the basic conditions and market structure for achieving competitive performance did not appear to be in place. This is an issue that OMOI will continue to explore and analyze.

5. **Electricity customers had better market options within regions with organized markets than within regions without organized markets.**

The fullest set of trading, scheduling and risk management products was offered in regions with organized markets (see Table 1; products available in natural gas markets are provided for comparison). The clearest advantage of organized markets for customers was the opportunity for buyers and sellers to trade electricity day ahead and in real time in open, transparent markets.

There were major differences in the scope and depth of information available to customers about price formation. In particular, customers in regions with organized markets received location-specific pricing and explicit pricing of congestion in real time. Pricing in regions with organized markets was transparent to the public and monitored in real time by market monitors. Customers in regions without organized markets had significantly less market information about prices, price formation, system conditions and transmission infrastructure needs than their counterparts in regions with organized markets. Outside organized markets there was limited market price information regarding the value of elec-

Table 1: Wholesale energy markets design, June 2003.

Legend: ■ = Yes; ● = No; ◆ = Not market based

Services Provided	Regions with organized markets					Regions without organized markets						Natural Gas
	ISO-NE	NYISO	PJM	ERCOT	CAISO	Southeast	Florida	Midwest	South Central	Southwest	Northwest	
Bilateral transactions	■	■	■	■	■	■	■	■	■	■	■	■
Active online physical trading (1)	■	●	■	■	■	■	●	■	●	■	■	■
Real-time energy market	■	■	■	■	■	●	●	●	●	●	●	●
Locational energy price	■	■	■	■	■	●	●	●	●	●	●	●
Hourly energy price	■	■	■	■	■	●	●	●	●	●	●	● (2)
Congestion price	■	■	■	■	■	●	●	●	●	●	●	●
Losses price	■	■	● (3)	■	■ (4)	●	●	●	●	●	●	●
Day-ahead energy market	■	■	■	●	●	●	●	●	●	●	●	●
Locational energy price	■	■	■	●	●	●	●	●	●	●	●	■ (5)
Hourly energy price	■	■	■	●	●	●	●	●	●	●	●	●
Congestion price	■	■	■	●	■	●	●	●	●	●	●	●
Losses price	■	■	● (3)	●	●	●	●	●	●	●	●	●
Ancillary services market	■	■	■	■	■	◆	◆	◆	◆	◆	◆	●
Capacity market	■	■	■	●	●	●	●	●	●	●	●	◆ (6)
Futures market	●	●	■	●	●	●	●	●	●	●	●	■
Regional transmission scheduling	■	■	■	■	■	●	●	■	●	●	●	●
Regional economic dispatch	■	■	■	■ (7)	■ (7)	●	●	●	●	●	●	●
Regional transmission planning	■	■	■	■	■	●	●	■	●	●	●	●
Regional interconnection process	■	■	■	■	■	●	●	■	●	●	●	●
Independent market monitor	■	■	■	■	■	●	●	■	●	●	●	●

Note: (1) An active market is defined as one that currently provides an historical price series. (2) An intra-day market for balancing physical natural gas operated. Prices posted on ICE during the delivery day revealed natural gas prices to customers for increments shorter than one day. (3) Losses are allocated to market participants based on a pro-rata share of total transmission losses. (4) Losses are allocated to sellers using generation meter multipliers, which reflect scaled marginal losses. (5) Gas market participants could transact for day-ahead gas. Unlike day-ahead markets for electricity, day-ahead gas purchases are not broken into hour-long increments. (6) Products traded: transmission capacity in the pipeline capacity release market and storage capacity in the storage market. (7) CAISO and ERCOT did not have day-ahead energy markets; economic dispatch was used in their real-time balancing markets only.

Source: OMOI.

tricity over time and across locations or of the regional needs for transmission and generation siting, resulting in:

- opaque (nontransparent) prices,
- less-efficient dispatch of power plants,
- use of less-efficient congestion management tools, and
- muted or distorted signals for investment, particularly where it is most needed.

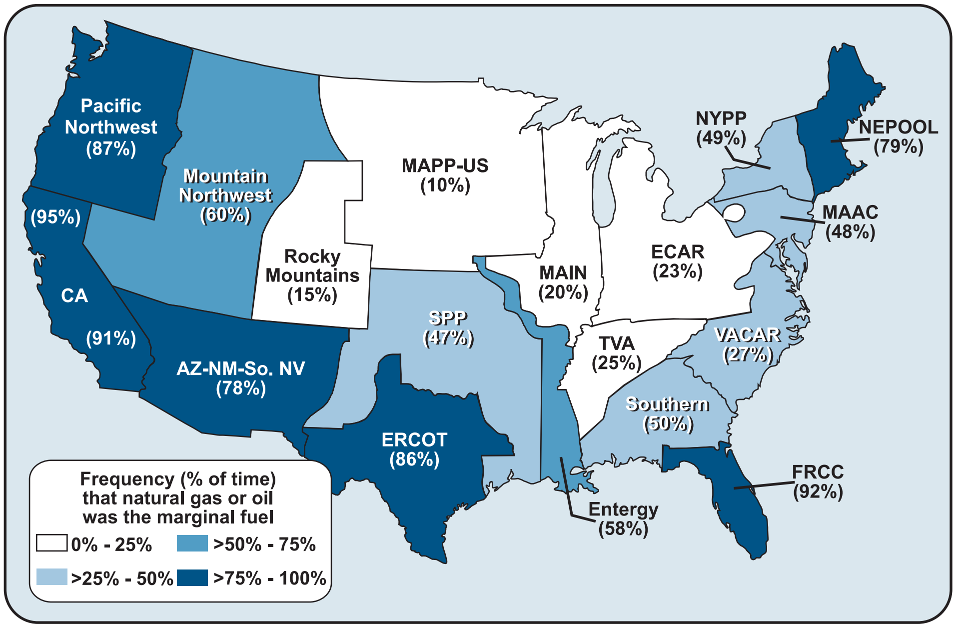
The poor quality of information outside organized markets limited the effective functioning of wholesale electric markets in those areas, potentially resulting in higher costs to customers.

6. Interdependence between electricity and natural gas markets increased, affecting prices, services and infrastructure requirements in both markets.

Nearly 96 percent, or 82 GW, of all generating capacity completed during the assessment period was gas-fired.[6] As shown in Figure 4, natural gas-fired units—both combustion turbines and combined-cycle plants—represented the marginal source of electricity in several key markets including CAISO, ERCOT, much of Florida, the Northwest and ISO-NE.

[6] Derived from EIA, Form 860.

Figure 4: Natural Gas is the marginal fuel in many regions.



Note: Percent of time gas or oil was projected to have been on the margin during peak hours in 2003.
Source: Cambridge Energy Research Associates (CERA). The use of this graphic was authorized in advance by CERA. No reuse or redistribution of CERA information is permitted without written permission by CERA. For more information contact CERA at (617) 866-5992.

Flexibility of existing services improved with the introduction of new services and products by the natural gas and power services industries, assisting electric market participants to reduce gas procurement costs or increase generating plant profits. The introduction of substantial new gas-fired generating capacity imposed new operational challenges on market participants and underscored the need for new services. Substantial incremental natural gas pipeline capacity, storage deliverability and liquefied natural gas (LNG) send-out capability were announced and certificated during the assessment period, in large part to meet the growing demand for gas by generators.

Prices for natural gas were increasingly influenced by the demand for electricity, which accounts for 27 percent of total U.S. natural gas consumption.[7] Because the short-run demand for fuel to generate electricity can be fairly price inelastic, this can increase gas prices. The high value of natural gas in power generation markets bid gas away from some lower-value applications, including major industrial users that depended on low-cost natural gas.

7. **Diverse market designs represented barriers to improved competitiveness and efficiency.**

Market designs across electricity markets were diverse. Organized electricity markets differed somewhat in product definitions and energy market operations, as well as in how they provided locational value signals and ancillary services. Electric markets in regions without organized markets depended on bilateral trading and voluntary reporting of price information to price index publishers to provide price signals to customers. These differences in market design, both in regions with and without organized markets, resulted in price seams between electricity markets, preventing efficient trading.

Differences in operational procedures between electricity and natural gas markets also created seams, which stifled efficient trading.

8. **Some of the nation's electricity markets were not efficiently signaling the need for infrastructure to meet growing energy requirements.**

Reserve margins and load data indicate that there were adequate, or in some cases, excess resources and reserves to meet regional demand during the assessment period. However, load pockets persisted in subregions where the capability to import lower-cost power was significantly constrained. Moderate amounts of investment were made, but often not in the locations where it was most needed.

7 EIA, Natural Gas Navigator, "U.S. Total Natural Gas Consumption by End Use," 2002 annual data, (tonto.eia.doe.gov/dnav/ng/ng_cons_sum_nus_a_d.htm).

Financial requirements for raising capital for new investment increased sharply and, coupled with lower wholesale market prices than in previous years, this resulted in the slowdown or cancellation of several announced projects. OMOI's analysis indicates that net revenues generated during the assessment period would not have been sufficient to cover total costs of operating plants or to attract new investment in supply or demand in many of the regions examined. This was appropriate in regions that have adequate reserves, but stronger and clearer price signals were needed in several load pockets. In addition, OMOI observed that bid mitigation may have dampened the price signals markets provided for new investment needed in load pockets.

Declines in the creditworthiness of several large market participants, which increased financing costs, drove up the costs of new investment. Lower credit ratings had implications not only for capital costs, but also for the liquidity and collateral requirements for trading and marketing in the futures and physical power and gas markets. Heightened collateral requirements and changes in how rating agencies assess the risk of power trading led to higher explicit or implicit equity support needs for these activities. This ultimately resulted in reduced electricity and natural gas trading and the exit of several participants. New players began to emerge with the resources to make new investments; however, they required more certainty about market rules and expected revenue streams than in the past.

9. Demand response would have been cost-effective in some key locations.

Demand response, an effective tool for dampening price spikes and protecting reliability, was largely missing from electricity markets during the assessment period. Because lack of demand responsiveness to price harms competitive wholesale markets, demand response must offer the customer an attractive proposition. In contrast to regions with organized markets, wholesale prices in regions without organized markets reflected day-to-day and seasonal changes, but not the real-time changes in prices that reflect the time-varying cost of producing electricity. Regardless of market design, however, most end-use customers in all regions were not aware of—and had no means to be aware of—the hourly, daily and seasonal changes in the wholesale costs of providing service to them.

A small percentage of customers had meters that measure usage close to time of use, and even fewer receive information directly about the prices prevailing in wholesale markets. Demand response in organized markets was successful in attracting some customers and had some measurable effects on market-clearing prices. However, the development of demand response resources was limited.

Given the relatively low energy prices during the assessment period, hypothetical customers would have found low or no net benefits from a hypothetical demand reduction in most regions of the country if they were dependent on energy bill savings alone. However, energy savings would have been sufficient to make demand reduction cost-effective for a demand responsive customer in New York City. Additional savings or revenues from demand response markets or sale of ancillary services or capacity reserves made demand reduction cost-effective in key load pocket locations in Southwest Connecticut and the Delmarva Peninsula in PJM.

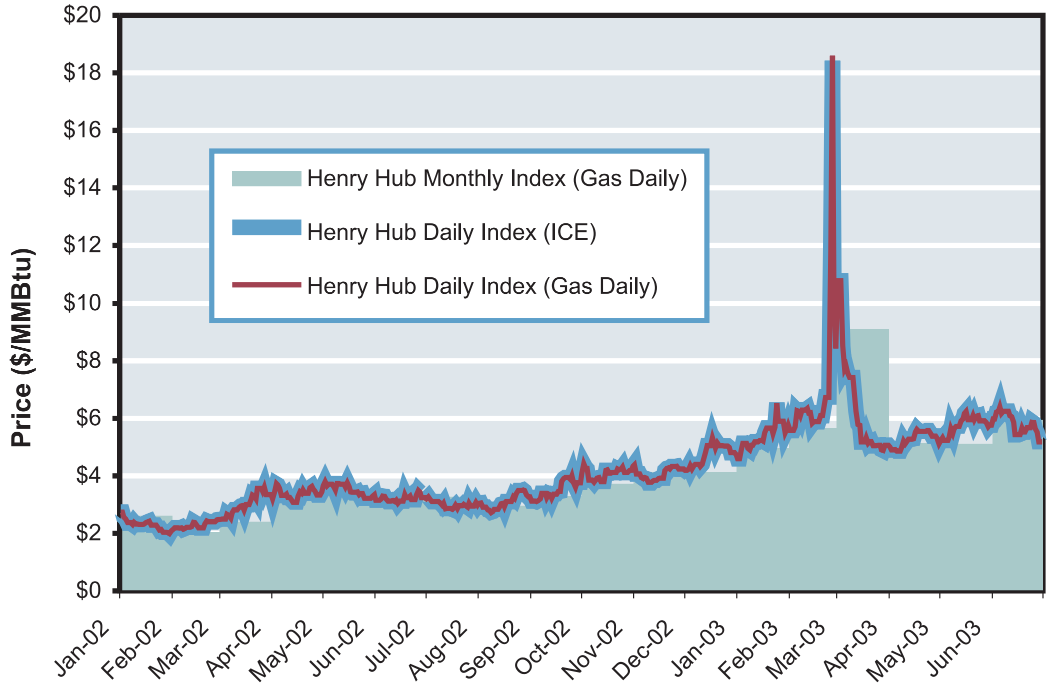
Natural Gas Markets

1. Natural gas prices during the assessment period generally behaved consistent with the fundamental forces of demand, supply and seasonality, but the market faced challenges.

The natural gas market exhibited characteristics of a well-functioning market by delivering products on time to customers and spurring reasonable levels of investment. Limited production and severe weather during the assessment period tightened supplies, which in turn led to higher prices, greater price volatility and severe swings in storage. In markets for financial transactions, the volume of trades decreased, a problem exacerbated by the erosion of credit quality among trading entities, including the bankruptcy of some merchant firms. Price transparency was further clouded by events that brought the credibility of the price indices into question.

As evident in Figure 5, average spot and forward market prices exhibited a significant upward shift in the past three years, reflecting tight supplies and tight storage conditions. Natural gas spot prices at Henry Hub escalated steadily through the assessment period, rising from $2/MMBtu in January 2002 to $6 in January 2003, then spiking briefly in February 2003 to $19 before quickly returning to the $6 range from March through June 2003. Futures prices indicate the magnitude of the shift in general price levels. The average next-month price was $2.04 from June 1990 through December 1999, but it more than doubled between January 2000 and June 2003, rising to $4.18.

Figure 5: Monthly natural gas prices peak in late-winter 2002 and remain high through following summer.

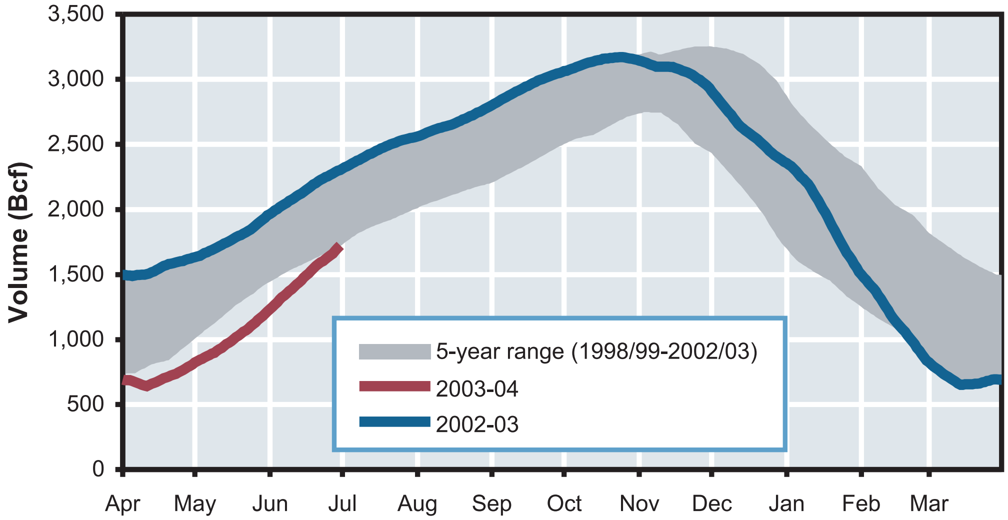


Source: Platts *Gas Daily* and ICE. Analysis and graphic by OMOI.

Customers responded to higher prices, as appropriate in an efficient market. Industrial and power customers reduced natural gas use 5.6 percent and 13.0 percent, respectively, between the first half of 2002 and first half of 2003, while the residential and commercial sectors increased consumption in response to weather conditions and continued growth. A full assessment of the consequences of higher natural gas prices and their effect on the national economy and customers was beyond the scope of this study, but there is concern that higher natural gas prices are driving some industrial production out of the United States and reducing disposable income for customers.

Supply tightness, and concern about this tightness, came from a 3.2 percent reduction in production in 2002, declining well productivity, uncertainty about whether production increased or decreased in 2003, reduced imports (while LNG imports increased dramatically, lower imports of natural gas via pipeline from Canada more than offset LNG's gains), increased exports to Mexico and continued land access restrictions. At the same time, as shown in Figure 6, storage inventory shifted from abundant in November 2002 to the low end of the five-year range in March 2003. Uncertainties about whether storage could be adequately replenished helped boost natural gas prices through summer 2003.

Figure 6: Storage use pushes upper and lower capacity limits.



Source: EIA. Analysis and graphic by OMOI.

2. **Market participants' capacity to manage price volatility weakened, primarily because of the increase in credit risk during the assessment period.**

During the assessment period, the volatility for next-day physical prices at Henry Hub rose, and both the price level and price volatility were higher on average than in any period during the early 1990s. Methods to reduce exposure to price volatility included the use of storage, long-term fixed-price physical contracts, firm pipeline capacity contracts and financial contracts.

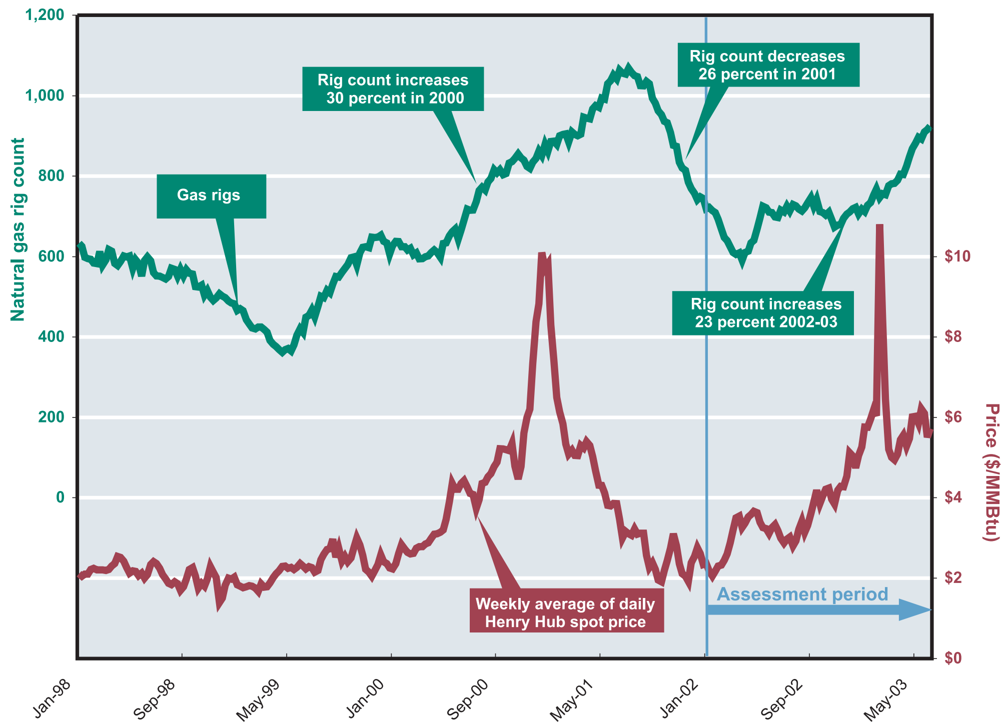
Reduced market liquidity weakened the ability of market participants to manage volatility. The loss of liquidity stemmed from the lower number of participants in the market (due to bankruptcies and withdrawals) and possibly from fewer trading positions per company. Underlying these trends were increased credit risk and default risk. This in turn led to difficulty finding creditworthy counterparties, a decrease in the amount of counterparties willing to transact long-term structured contracts and a decline in industry confidence. There were also reported increases in bid-ask spreads, another indication of credit strains and lower market liquidity.

3. **New participants and new products demonstrate that the market gained efficiency as it addressed the credit problems that hindered its effectiveness during the assessment period.**

Existing and new industry players, typically with stronger credit ratings, entered the marketing and trading segments of the industry, partially filling the void left by the exit of many merchant energy companies prior to the assessment period. New marketing and trading participants included marketing affiliates of producers, LDCs and financially oriented firms, such as large banks and hedge funds.

In 2002, Nymex and ICE introduced new products for credit clearing that enable participants to manage credit risk by transferring the counterparty credit risk in bilateral transactions to the clearing organization. Market participants actively purchased these products, but high margin requirements and limited credit capacity inhibited some participation.

Figure 7: 2003 producer drilling response to high prices is moderate.



Note: Prices not adjusted for inflation.

Source: Platts GASdat, Platts *Gas Daily* and Baker Hughes. Analysis and graphic by OMOI.

4. **The physical natural gas market coped with imperfect transparency and eroded credibility, while the financial markets provided forward price transparency through several robust indicators.**

The quality of price information available to physical market participants varied because the lack of liquidity and transparency inhibited price discovery at many of the trading points outside of the most well known, such as Louisiana's Henry Hub, an active physical-market trading point as well as the delivery point for Nymex gas futures contracts. As a result, physical markets were highly dependent on indices assembled from information provided by market participants who voluntarily reported to index publishers and indices based on exchange-conducted transactions.

Enron's late-2001 declaration of bankruptcy, allegations of misreporting by traders to the index publishers and revelations of wash trading in April 2002 undermined credibility of indices. The credibility problem and corresponding changes in industry participant business strategies caused the volumes of transactions reported to index providers to fall sharply during the assessment period.

Efforts to restore confidence in indices and thereby enhance price discovery have been multifaceted. Industry groups developed and proposed best practices,[8] while index developers increased the market participants' ability to examine liquidity factors and market trends at multiple locations by categorizing each location by "tiers" that indicated the volume of transactions. ICE began publishing the number of counterparties and number of transactions per location traded on its system.

Nevertheless, physical market price discovery continued to be a problem. Many participants did not report to index providers or did not report on all trading points. While the entire market benefits from all participants reporting transactions, individual participants may see no individual benefit in submitting all their transactions to an index provider, a factor that may discourage reporting.

[8] FERC issued a policy statement reflecting a consensus on ways to improve the current voluntary price reporting system and conducted a survey in October 2003 to determine whether, how and to what extent market participants reported price data to index developers.

Prices in forward months are necessary for participants planning hedges and making investment decisions. During the assessment period, forward price transparency was available through the Nymex Henry Hub futures contract, which offered prices out for six consecutive years. Forward price transparency at locations other than Henry Hub were available for shorter periods of time. Forward price transparency improved during the assessment period with the introduction in 2002 of financial OTC swaps on Nymex's ClearPort system.

5. **The investment response to higher prices was moderate, but price signals for needed investment were reasonably strong.**

Forward price expectations increased in 2003, sending signals to investors that higher natural gas prices might be sustainable and additional investment justified.

Despite strong price signals, the supply response did not fully temper tightness in the overall North American supply and demand balance. A moderate increase in gas-directed drilling and diminishing recoveries per natural gas well completed appeared to mute the new domestic natural supply response. As shown in Figure 7, the drilling rig count did not reach levels achieved after the 2001 price spike. Factors contributing to this moderate response included drilling companies' efforts to strengthen their balance sheets, avoid creating a glut in production and avoid investments in marginal prospects.

In response to the supply outlook and to FERC's change in policy regarding LNG facilities, developers proposed more than 30 LNG receipt terminals in North America to supplement domestic supplies. As is the case for other capital intensive projects, the number of LNG projects that will actually be built will be less than those planned because investors must overcome pricing, contracting, siting, permitting and other concerns to secure financing, successfully execute construction and operate. Even if successful, new LNG investment will not substantially augment short- to medium-term natural gas deliverability because new facilities require years to complete.

Investment in new storage capacity was low, increasing 0.3 percent (23 Bcf) from 2001 to 2002. The slow rate of capacity additions reflects the many challenges to storage investment, including locating, acquiring and developing a suitable storage site, regulatory delay and financial and credit issues. For non-traditional, high-deliverability storage with higher development costs, the economics are dependent upon projecting trading benefits from volatility via "real options" or other techniques, in addition to the traditional seasonal arbitrage. Unfortunately, the advantages of trading around volatility or real option value are difficult for lenders and investors to quantify, especially with the decreased activity in the wholesale trading sector and corresponding reduced liquidity. Substitutes for storage (e.g., new pipeline capacity, remarketed pipeline capacity and financial products) also compete with increased storage investment.

Pipeline investment appeared to be appropriate given basis signals. Before market participants contractually commit to a project, forward market basis values or swaps along key pipeline corridors must signal that added capacity is needed and likely to be profitable.[9] The level of pipeline completions grew steadily through 2002, with indications that 2003 investment was slightly lower. Some pipeline projects were delayed or cancelled. This was primarily because many projects remained economically marginal, especially in light of changing business conditions and the difficulty of obtaining long-term contracting due to a lack of shipper commitments and/or shipper creditworthiness.

Longer term, FERC certificated 2,234 miles (7.4 Bcfd) of pipeline during the assessment period, indicating that companies are planning to continue to invest. OMOI analysis of financial basis differentials in the Rockies and San Juan basin for example, suggest that price signals justify new pipeline construction within the next two years. In contrast, the differential from Henry Hub to Transcontinental Gas Pipe Line Corp.'s (Transco's) Zone 6-NY provides partial market signals supporting investment in the future, but does not fully support new construction from the Gulf of Mexico.

[9] A basis differential is the difference between a natural gas price point (e.g., a market hub, citygate or supply receipt area) and a reference point, most often Henry Hub. During periods of low pipeline capacity utilization, the basis differential will reflect the variable costs of transportation and typically be below the 100 percent load factor pipeline tariff rate in an efficient natural gas market. As capacity constraints develop, the basis differential will reflect regional supply and demand conditions in a market and, depending on the severity of the constraint, the basis may exceed the cost-based tariff rate for transmission capacity, occasionally by large multiples. Consistently and sufficiently high basis differentials signal continued constraints and the need for new pipeline capacity.

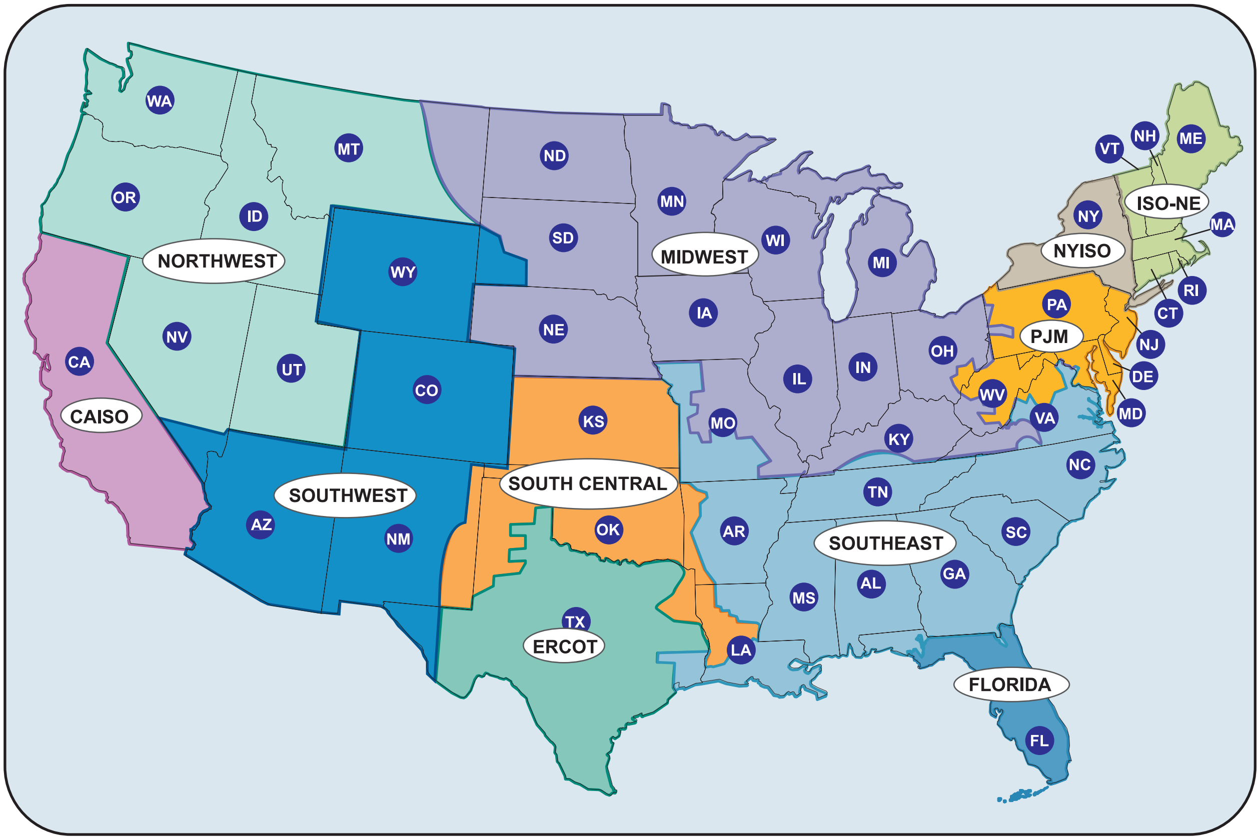
Electricity Market Performance

The Commission's ability to assess the performance of electric markets varied substantially across the United States as well as across electricity services and products. In most cases, more information about the formation of short-term market prices was available in regions where Commission-approved organized markets—ISOs or RTOs[10]—operated than in regions where they did not. Long-term price information was limited in all regions. During the assessment period, regions with operating organized markets were ISO-NE, NYISO, PJM, ERCOT and CAISO. Regions without operating organized markets were the Southeast, Florida, the Midwest, South Central,[11] the Southwest and the Northwest. These regions are shown in Figure 8.

[10] An RTO is an independent entity approved by FERC to provide nondiscriminatory wholesale electric transmission service under one tariff for a large geographic area. To be approved by the Commission, an RTO must meet four characteristics and perform eight functions listed in Order 2000. The four characteristics are independence from market participants, appropriate scope and regional configuration, operational authority over the regional grid and responsibility for short-term reliability. The eight functions are tariff administration, congestion management, management of parallel path flow, provision of ancillary services, provision of transmission information through OASIS and calculation of available transfer capability (ATC), market monitoring, planning and expansion and interregional coordination. Similar to an RTO, an ISO is an independent entity that has been approved by FERC to provide nondiscriminatory wholesale electric transmission service under one tariff. An ISO must satisfy 11 ISO principles listed in Order 888, that require fair and nondiscriminatory governance, independence from financial interests of participants, open access under a grid-wide tariff, control over operation and short-term reliability, efficient pricing and congestion management, public and timely availability of transmission information and coordination with neighboring regions. Though somewhat different in scope and function, RTOs and ISOs are similar in that the Commission grants them the authority to operate, in a nondiscriminatory manner, the transmission assets of participating transmission owners in a fixed geographic area. They also often operate short-term markets designed to optimize generation costs. Some ISOs and RTOs operate both real-time and day-ahead markets to balance the forecasted volumes with the volumes actually consumed.

[11] During the assessment period, Entergy Corp. was in preliminary stages to join SeTrans, a proposed RTO in the Southeast. For this reason, its service area was considered as part of the Southeast, not South Central. Depending on future activities, we may realign the regions in subsequent reports.

Figure 8: Map of electricity regions assessed.



Note: Regional maps are located in Appendix 1.

Source: OMOI.

In both regions with and without organized markets, short-term bilateral markets exist.[12] These are primarily day-ahead markets, which are forward markets for electricity to be supplied the following day. In regions with organized markets, additional day-ahead markets have developed, as have real-time markets. Organized day-ahead markets are short-term forward markets that settle or determine the price for one-hour periods for delivery the next day. Real-time markets are spot markets involving physical delivery on the operating day that typically determine prices for shorter time-periods (e.g., 5 or 10 minutes), even though an hourly average price may be published for settlements. During the assessment period, ISOs and RTOs did not operate markets for longer-term electricity transactions. All long-term contracting was conducted bilaterally. Table 2 summarizes the key characteristics of wholesale electricity markets as operated during the assessment period.

[12] The bilateral market is a combination of bilaterally negotiated contracts for energy and purchases of transmission and ancillary services under regulated tariff rates. In many regions of the country, the energy commodity is packaged with ancillary and transmission services provided by the same seller. A bilateral physical energy transaction is a contract to deliver a specified number of MWs to a specified location (or trading point) for a specified period of time. The terms of the contracts need not be standardized, although a prototype or master wholesale power agreement has been developed and gained widespread use by the industry in recent years (Edison Electric Institute and National Energy Marketers Association, Master Power Purchase and Sale Agreement, 2000). The bilateral contract may provide for delivery of power the next day, for several days, a month, multiple months, a year or multiple years. In the most basic form of a bilateral market, companies identify, evaluate, select and contract with bilateral trading partners based on individual relationships and processes.

Table 2: Wholesale electric market products.

Legend: ■ = Yes ● = No

		Bilateral transactions	Real-time market	Day-ahead market	Ancillary services markets	Capacity market	Active physical day-ahead ICE market	Futures market	Financial transmission rights	Virtual bidding	OTC financial products
Regions with organized markets	ISO-NE	■	■*	■*	■*	■* (2)	■	●	■*	■*	■
	NYISO	■	■*	■*	■*	■* (2)	●	●	■*	■*	■
	PJM	■	■*	■*	■*	■* (2)	■		■*	■*	■
	ERCOT	■	■*	●	■*	●	■	●	■*	●	■
	CAISO	■	■*	●	■*	●	■	●	■*	●	
Regions without organized markets	Southeast	■	●	●	● (1)	●	■ (3) Entergy	●	●	●	■ (3) Entergy
	Florida	■	●	●	● (1)	●	●	●	●	●	●
	Midwest	■	●	●	● (1)	●	■	●	●	●	■ (3) Cinergy
	South Central	■	●	●	● (1)	●	●	●	●	●	●
	Southwest	■	●	●	● (1)	●	■	●	●	●	■
	Northwest	■	●	●	● (1)	●	■	●	●	●	■

Notes: *Designates a market operated by an ISO. (1) Ancillary services were provided at cost-based tariff rates or negotiated bilaterally. (2) ISO conducts an auction-based capacity market. Bilateral contracts and self-supply were also allowed. (3) Whereas products were available more widely within other regions, products were only available for a single price point in this region.

Source: OMOI.

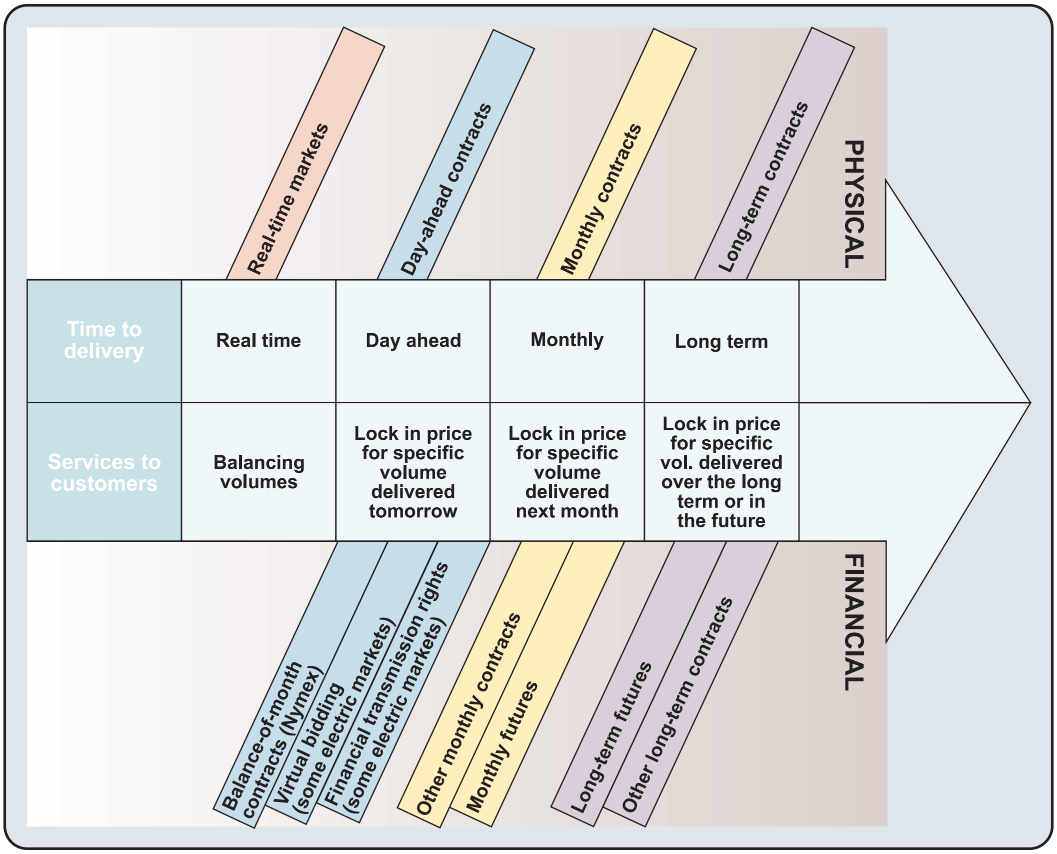
Table 2 illustrates that market options for customers were quite different between regions with organized markets and regions without organized markets. The clearest advantage was the opportunity for customers within regions with organized markets to purchase day-ahead or real-time energy in open, transparent markets that provided explicit information on the locational price of energy, congestion and losses. These regions also provided markets and public market prices for competitive provision of several ancillary services and capacity reserves.

Wholesale customers generally purchase electricity products for four basic purposes:

- to secure power for delivery at the time and location of their choice,
- to minimize exposure to under- or over-estimating their expected demand at a future time,
- to minimize exposure to fluctuations in the prices of electricity, underlying fuels and transmission congestion, and
- to take advantage of market deals that are more economic than self-generation.

A variety of short-term and long-term physical and financial products can achieve these objectives efficiently; Figure 9 represents a list of products used to manage the physical delivery of electricity and the associated risks.

Figure 9: Physical and financial power markets work efficiently in tandem.



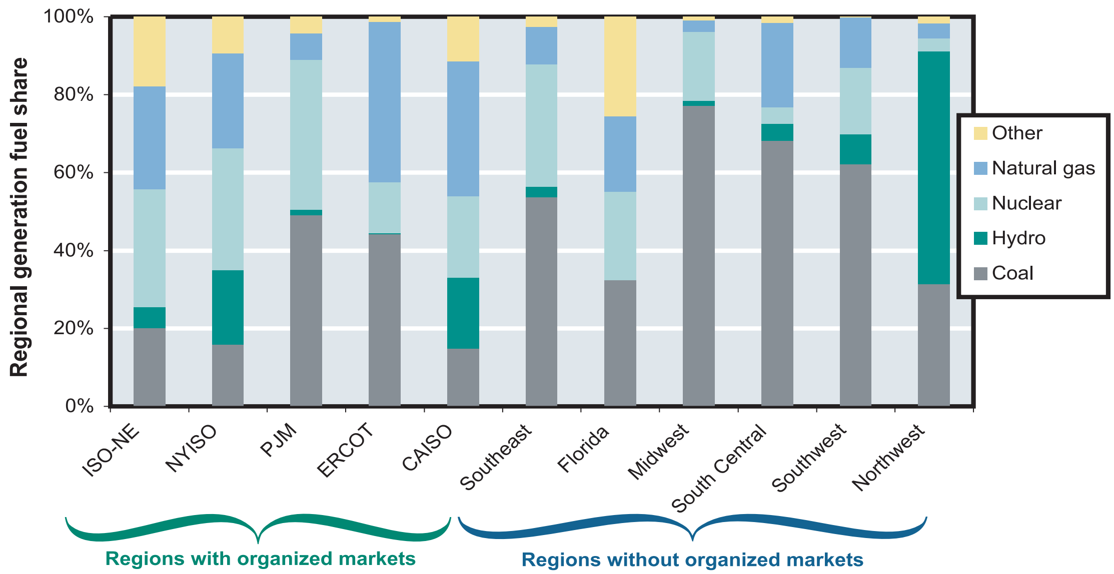
Source: OMOI.

In a market system, market participants bear the risks of supply and demand fluctuations. Investors bear the risks of quantity, type, location and final cost of investments. Customers should be able to contract for some of their electricity needs in advance of the time of delivery and consumption, just as they are able to do with other products. Likewise, they should be able to procure other products at or very near to the time of delivery and consumption. Further, they should be able to purchase products that allow them to manage a variety of risks—that they may not accurately forecast their demand when entering into an advance contract, that prices will change or that prices will be volatile. Incomplete markets (those that lack some of the products depicted in Figure 9) raise costs to customers because risks and uncertainty are not efficiently shifted to those willing to undertake them for potential profit. Long-term contracting, for example, may have benefited from more complete market options during the assessment period. Approximately 28 percent of reported U.S. sales[13] were delivered under long-term contracts of one year or longer, but long-term electricity markets offered limited forward price transparency to facilitate this contracting. Similarly, long-term contracting for set volumes is facilitated by a balancing market or spot market to fill the gap between forecasted and actual demand. However, customers in several regions did not have access to a competitive balancing market during the assessment period.

The development of organized markets has not been uniform across the United States (see Figure 2). One reason that some regions have not progressed in development of open markets is the existence of indigenous low-cost resources. As seen in Figure 10, regions with low percentages of indigenous low-cost hydroelectric and coal resources tended to have organized markets in place. This is in contrast to regions with high percentages of indigenous low-cost resources, which tended to stay in traditional regulated structures.

[13] Derived from FERC EQR, Fourth Quarter 2002 through Second Quarter 2003. For more information on EQR data used in this report see footnote 5.

Figure 10: Regions in organized markets tended to have low shares of indigenous low-cost generation resources.



Source: Platts POWERdat, Modeled Production Cost-Ownership-Based dataset from EIA Form 906, EIA Form 759 and FERC Form 423. Analysis and graphic by OMOI.

We have observed that reported electricity prices over the assessment period generally behaved in accordance with observed forces of supply and demand, a key characteristic of competitive markets. While prices have shown volatility, price movements were consistent with drivers like electric demand and fuel costs. Consequently, while this section establishes the basis for these findings, we also consider factors that may limit the competitiveness and efficiency of markets, including local market power, transparency, barriers to entry, development of associated risk management markets and adequacy of price signals and market structure to create appropriate incentives for investment.

We have organized this electricity section into five parts:

- Market Structure
- Prices, Market Activity, Congestion and Mitigation
- Market Design and Price Transparency
- Risk Management
- Infrastructure Investment

Market Structure

Conventional economic analysis posits that market performance is a function of market structure. The characteristics of an electric market's structure that are the subject of Commission observation and analysis include:

- the number of buyers and sellers active in the market,
- concentration of ownership of generation,
- the extent of vertical integration of market participants, and
- barriers to market entry.

In particular, vertical market power (control of transmission) and horizontal market power in generation are two main concerns. The Commission has deemed electric transmission non-competitive and has employed forms of cost-based regulation to protect customers from the exercise of vertical market power in transmission service. However, more than a decade ago the Commission began to make use of competitive market forces to the extent possible to achieve just and reasonable prices for wholesale sales and purchases of electric power.[14]

[14] See Footnote 1.

The courts have held that the Federal Power Act allows for market-based pricing only if the markets are competitive. “When there is a competitive market the FERC may rely upon market-based prices in lieu of cost-of-service regulation to assure a ‘just and reasonable’ result.”[15] Additionally, the courts have found that “[i]n a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that price is close to marginal cost, such that the seller makes only a normal return on its investment.”16

Number of Buyers and Sellers

Generally, regions with organized markets had numerous buyers and sellers and the ownership of generation was spread among several entities, primarily independent power producers. Market participation by buyers and sellers was less in regions without organized markets and ownership of generation was more concentrated. These two elements of market structure are examined in more detail in turn.

There were hundreds of participants in organized markets, as indicated in Table 3.

Most generators and wholesale customers in these regions participated in the ISO or RTO markets, although the level of reliance varied. For example, approximately 50 percent of all wholesale transactions in New York reported to FERC took place in its ISO markets, whereas market participants reported that use of the CAISO balancing markets represented about 1 percent of their total energy transactions.17 The amount of energy traded in organized markets during the assessment period was significant and, as indicated by Table 4, appears to be growing.[18]

Figure 11 presents the average and highest number of counterparties trading on ICE daily at six bilateral trading hubs. The number of counterparties trading natural gas at Henry Hub is shown for comparison. The Cinergy trading hub in the Midwest was ICE’s most active bilateral electricity trading point in the country during the assessment period, although the number of counterparties was still low compared to the number of counterparties in organized markets. A relatively large number of counterparties were active at this hub, with significantly fewer in the other regions without organized markets.

Table 3: Number of wholesale buyers and sellers in organized markets.

Region	Wholesale Buyers and Sellers	Generators only
ISO-NE	230	46
NYISO	216	67
PJM	251	25
ERCOT	140	64
CAISO	82	N/A

Source: ISO websites and ISO market monitoring unit (MMU) response to OMOI data requests.

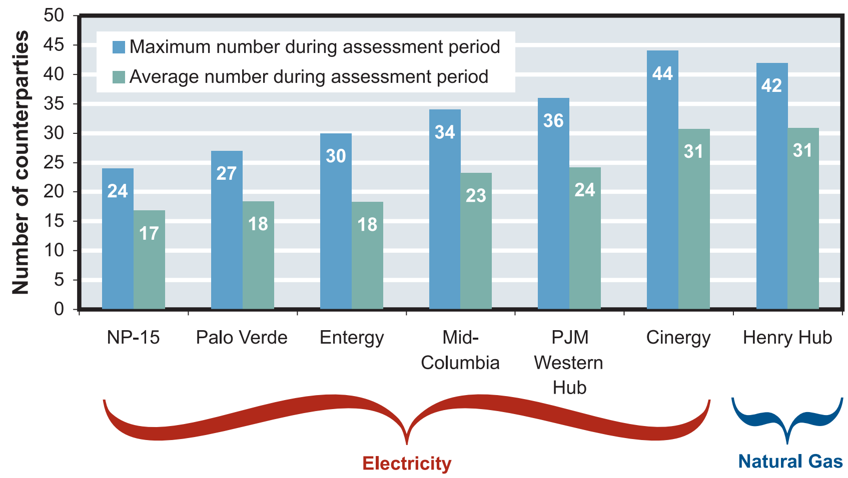
Table 4: Electricity volumes transacted in organized markets.

000 GWh (cumulative)	Day-ahead market			Real-time market		
Region	2001	2002	2003 thru 6/30/03	2001	2002	2003 thru 6/30/03
ISO-NE	(1)	(1)	11 (2)	30	41	8 (2)
NYISO	161	162	77	3	1	2
PJM	42	104	60	57	119	67
ERCOT (3)	N/A	N/A	N/A	1	7	5
CAISO (4)	N/A	N/A	N/A	14	2	1

Notes: (1) Day-Ahead Market initiated March 1, 2003. (2) Only includes transactions from March 1 to June 30. In addition, after March 1, 2003 the real-time market was only a residual market. (3) ERCOT does not have a day-ahead market. Real-time energy balancing market began July 31, 2001. Real-time market data are for real-time Balancing Up energy. (4) CAISO does not have a day-ahead market. Real-time market data are for Incremental (INC) energy.

Source: ISO websites and ISO MMU response to OMOI data requests.

Figure 11: Cinergy electricity trading on ICE reaches Henry Hub gas liquidity.



Source: ICE. Analysis and graphic by OMOI.

Table 5: Reported electricity volumes transacted bilaterally.

			Average daily volume (GWh)		
			2001 (full year)	2002 (full year)	2003 (first half)
Regions with organized markets	ISO-NE	MWD	48	14	10
		ICE	12	26	11
	NYPP ZG	MWD	11	8	3
		ICE*	N/A	N/A	N/A
	PJM	MWD	111	77	32
		ICE	66	129	66
	ERCOT	MWD	34	34	12
		ICE	7	15	8
	NP-15	MWD	10	21	17
		ICE	7	31	29
Regions without organized markets	Entergy	MWD	69	54	13
		ICE	43	73	30
	Florida	MWD	1	2	0
		ICE*	N/A	N/A	N/A
	Cinergy	MWD	180	127	61
		ICE	128	193	130
	SPP North	MWD	6	5	0
		ICE*	N/A	N/A	N/A
	Palo Verde	MWD	17	22	11
		ICE	10	32	22
	Mid-Columbia	MWD	16	20	16
		ICE	6	42	33

Note: *ICE did not report trade volumes for day-ahead power for NYPP ZG, Florida or SPP North. *Megawatt Daily* volumes reflect on-peak transactions surveyed by the trade publication. *Megawatt Daily* data have been modified to make them comparable to ICE data. *Megawatt Daily* volumes have been multiplied by 16 to convert from a 16 peak-hour MW contract into a MWh. Final volumes are converted to GWh. In addition, since *Megawatt Daily* volumes include both buy and sell sides of transactions and ICE volumes include only the sell side of transactions, ICE volumes were doubled.

Source: Platts *Megawatt Daily* and ICE.

Reported trading activity in the other regions without organized markets was significantly less than at Cinergy, as can be seen in Table 5. Indeed, the level of reported trading activity at the Florida and SPP North trading hubs was not indicative of a liquid market.

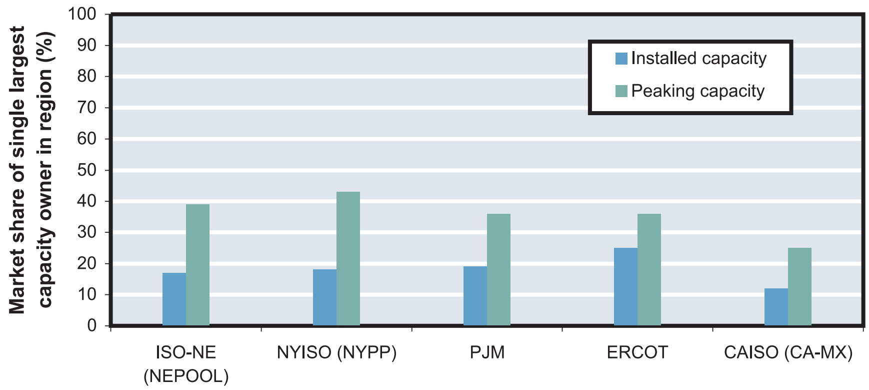
15 Elizabethtown Gas Co. v. FERC, 10 F.3d 866, 870 (D.C. Cir. 1993)

16 Tejas Power Corp. v. FERC, 908 F. 2d 998, 1004 (D.C. Cir. 1990)

17 Derived from FERC EQR, Fourth Quarter 2002 through Second Quarter 2003. For more information on EQR data used in this report see footnote 5.

18 As discussed in more detail in the examination of market performance and prices, the apparent decline in volumes traded in the CAISO and NYISO real-time markets from 2001 to 2002 appear consistent with the design and purpose of these markets—to balance differences between predicted and actual consumption.

Figure 12: Capacity market share lower in organized markets.



Note: Installed capacity is the measured capacity or the capacity demonstrated to have been available during the hour of highest output of a generating unit. For purposes of this analysis, the working definition of a peaking unit is a natural gas or oil-fired unit with a heat rate greater than 10,000 Btu/kWh or a combustion turbine or internal combustion unit smaller than 50 MW in size with no reliable heat rate information reported.

Source: Platts POWERdat, Modeled Production Costs-Ownership-Based dataset for calendar year 2002. Analysis and graphic by OMOI.

Market Concentration and Vertical Integration

High levels of concentration in generation ownership and sales are an indicator of the potential to exert market power in a region, creating inefficiency and raising prices to customers. Figure 12 shows the largest market share of generation[19] in each organized market for 2002. This comparison shows that no one firm controlled a dominant share of total installed generation capacity in any region with organized markets. However, concentration in peaking capacity appears higher.

ISO-NE, for example, had a relatively competitive market structure with ownership of generation spread across several entities.[20] Referring to the two left-hand columns of Figure 13, the 10 owners of the largest shares of generation accounted for 70 percent of total generating capacity in the region but no single entity controlled more than 20 percent of total installed capacity or the MWh produced.21

Only one vertically integrated utility (transmission owner that owns generation capacity and provides distribution services) was among the top 10 generation owners, and 55 percent of its generation was owned by the utility. The remaining 45 percent was owned by a non-regulated affiliate. Two entities, both non-utilities, owned greater than a 20 percent share of peaking capacity and had greater than a 20 percent share of the peaking MWh generated. Comparison of the ownership shares with the corresponding share of energy produced by the entity indicates that the share of energy sold by an entity within a region with an economic dispatch process was not necessarily proportional to ownership.

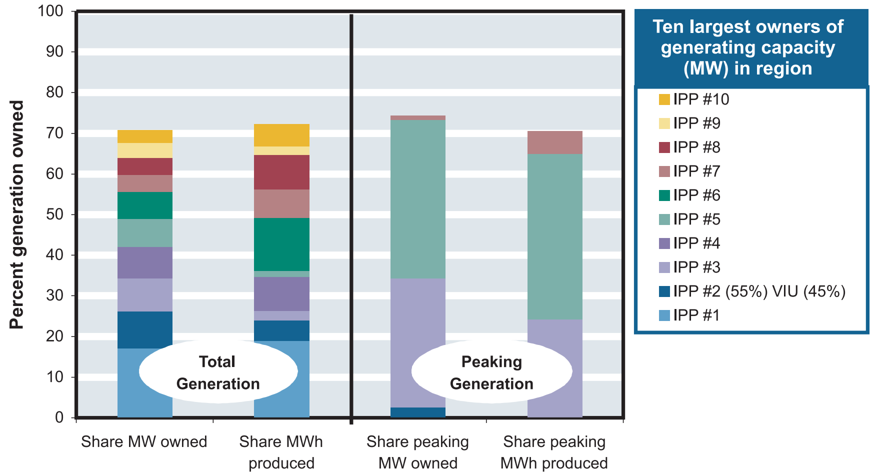
As previously mentioned, within the relatively competitive structures of the organized markets, there were peak periods and locations where concentration of generation ownership was higher. In New York, for example, as seen in Figure 14, one company controlled a significant portion of peak period capacity, but just 18 percent of total installed capacity.

[19] The regional market share calculations in this section are of gross capacity installed and MWh generated and are not adjusted for generation used to meet obligations for operating reserves, retail service or long-term contracts. The treatment of these factors, among others, is under consideration by the Commission in Docket No. PL02-8-000 regarding a Conference on Supply Margin Assessment.

[20] Entities are identified by type: Vertically Integrated Utility (VIU), Independent Power Producer (IPP), Municipal utility (Muni), federal power administration (Federal), cooperative utility (COOP), other type of public power agency (Pub Auth). The number assigned to an entity represents ranking within the region being examined, and does not track to any other region.

[21] For purposes of this analysis, markets with a single entity owning 20 percent or less of the generation are considered to exhibit low levels of concentration, shares of 20 to 35 percent are considered moderately concentrated and those with shares above 35 percent are considered highly concentrated.

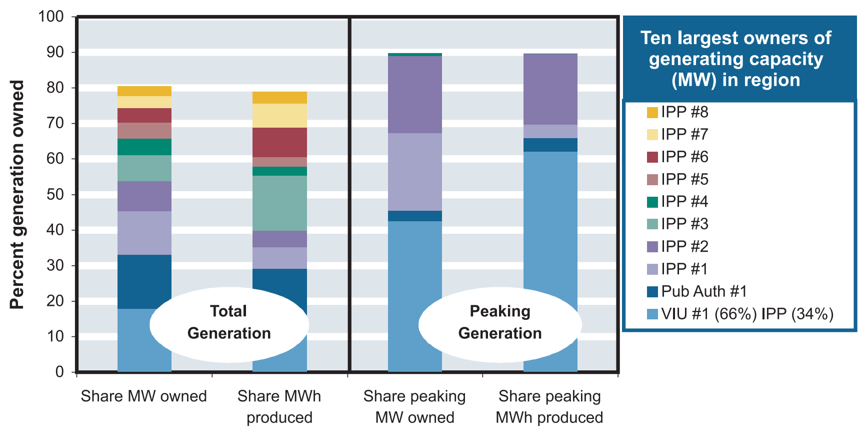
Figure 13: Multiple companies own New England generation.



Note: Installed capacity is the measured capacity or the capacity demonstrated to have been available during the hour of highest output of a generating unit. For purposes of this analysis, the working definition of a peaking unit is a natural gas or oil-fired unit with a heat rate greater than 10,000 Btu/kWh or a combustion turbine or internal combustion unit smaller than 50 MW in size with no reliable heat rate information reported. MWh produced is the net generation of an electric generating unit, or the amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries. Electricity required for pumping at pumped-storage plants is regarded as electricity for station service and is deducted from gross generation.

Source: Platts POWERdat, Modeled Production Costs-Ownership-Based dataset for calendar year 2002. Analysis and graphic by OMOI.

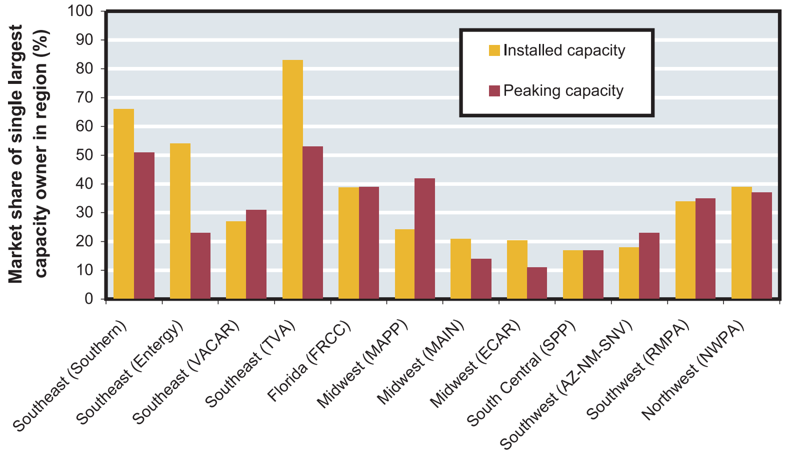
Figure 14: New York peaking generation concentration high.



Note: Installed capacity is the measured capacity or the capacity demonstrated to have been available during the hour of highest output of a generating unit. For purposes of this analysis, the working definition of a peaking unit is a natural gas or oil-fired unit with a heat rate greater than 10,000 Btu/kWh or a combustion turbine or internal combustion unit smaller than 50 MW in size with no reliable heat rate information reported. MWh produced is the net generation of an electric generating unit, or the amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries. Electricity required for pumping at pumped-storage plants is regarded as electricity for station service and is deducted from gross generation.

Source: Platts POWERdat, Modeled Production Costs-Ownership-Based dataset for calendar year 2002. Analysis and graphic by OMOI.

Figure 15: High generation ownership shares in regions without organized electricity markets.



Note: Installed capacity is the measured capacity or the capacity demonstrated to have been available during the hour of highest output of a generating unit. For purposes of this analysis, the working definition of a peaking unit is a natural gas or oil-fired unit with a heat rate greater than 10,000 Btu/kWh or a combustion turbine or internal combustion unit smaller than 50 MW in size with no reliable heat rate information reported.

Source: Platts POWERdat, Modeled Production Costs-Ownership-Based dataset for calendar year 2002. Analysis and graphic by OMOI.

Although no single entity owned more than a 20 percent share of total installed capacity or energy produced, one entity, a vertically integrated utility with non-utility affiliates, owned 43 percent of the peaking capacity in the region and generated 62 percent of the peaking MWh. This is a serious concern because the capacity of this entity was the pivotal supply in the significant load pockets of New York City and Long Island.[22]

Nevertheless, pivotal supplier tests performed by the market monitoring units (MMUs) of the ISOs and RTOs show declines in market concentration in some organized ISO markets as market concentration was diluted by new entrants. In New England for example, while there were a significant number of hours during the assessment period during which pivotal suppliers existed, the average residual supply index (RSI)[23] improved since the opening of the ISO markets in May 1999.[24] Nevertheless, the RSIs in load pockets such as Southwest Connecticut and NEMA/Boston areas revealed significantly more hours during which pivotal suppliers existed than was indicated by the system-wide measures.[25]

In California, there were pivotal suppliers in about 6 percent of hours in 2000 and 12 percent of hours in 2001. In 2002, which is within the assessment period, suppliers were pivotal in less than 0.1 percent of hours. CAISO measures pivotal supplier conditions through use of an RSI. CAISO's Department of Market Analysis (DMA) has recommended accounting for "possible collusion" by adding a 10 percent margin to the residual supply screen for pivotal suppliers, which increases the hours with pivotal suppliers. Using this assumption results in pivotal suppliers in 20 percent of hours in 2000, 36 percent of hours in 2001 and 1.4 percent of hours in 2002.[26]

Appendix 3 details the pattern of generation ownership in the remaining regions with organized markets.

In contrast to the organized markets, many regions without organized markets exhibited few buyers and sellers (as approximated by trading volumes) and high concentration of generation ownership by transmission owners and control area operators. As shown in Figure 15, many of these regions exhibited high market shares for the single largest owner in both installed and peaking capacity generation markets, largely because of the dominance of vertically integrated utilities and the historical development of the regions.

22 The entity, KeySpan Corp., has recently added a new generating unit in Queens increasing the company's total electric generation capacity by 12 percent. KeySpan is also seeking approval to build two additional power plants on Long Island. KeySpan Corp., Jan. 6, 2004.

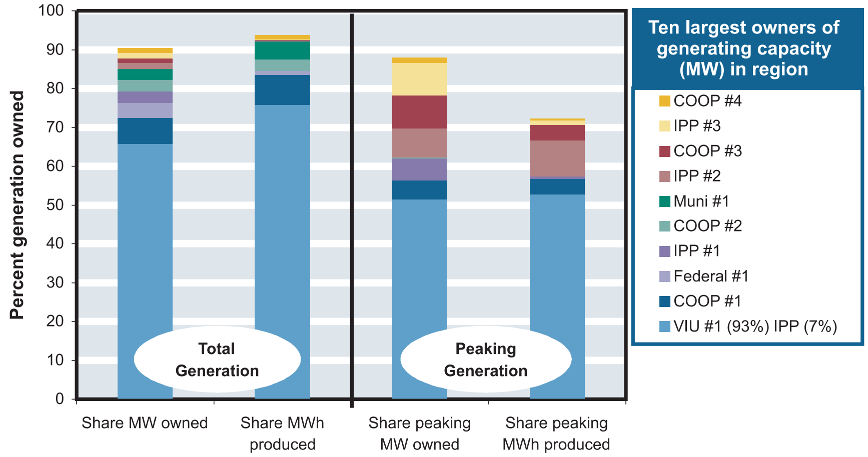
23 Residual supply is the amount of generation capacity remaining in the market, after subtracting the capacity of the largest supplier. If RSI exceeds 100 percent, this indicates that the alternative suppliers have sufficient capacity to meet demand without the largest supplier, who is thus presumed to have relatively little influence on the market-clearing price for a given hour. However, if the RSI is below 100 percent, this indicates that the largest supplier's capacity is needed to meet market demand and the supplier is considered pivotal in determining the market-clearing price for that hour.

24 ISO New England Inc., Annual Markets Report May–December 2002, Aug. 13, 2003.

25 Data response from ISO-NE MMU.

26 Data response from CAISO-DMA, and "Predicting Market Power Using the Residual Supply Index," Presentation to FERC Market Monitoring Workshop, Anjali Sheffrin, DMA, California Independent System Operator, Dec. 3, 2003.

Figure 16: Southern subregion of SERC generation ownership concentrated.



Note: Installed capacity is the measured capacity or the capacity demonstrated to have been available during the hour of highest output of a generating unit. For purposes of this analysis, the working definition of a peaking unit is a natural gas or oil-fired unit with a heat rate greater than 10,000 Btu/kWh or a combustion turbine or internal combustion unit smaller than 50 MW in size with no reliable heat rate information reported. MWh produced is the net generation of an electric generating unit, or the amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries. Electricity required for pumping at pumped-storage plants is regarded as electricity for station service and is deducted from gross generation.

Source: Platts POWERdat, Modeled Production Costs-Ownership-Based dataset for calendar year 2002. Analysis and graphic by OMOI.

Southern Co., for example, controlled 66 percent of installed generation and 51 percent of peaking capacity in its market. The second largest generator in the Southern service area[27] controlled 7 percent of installed and peaking capacity.

Similarly, in both the Entergy and TVA[28] subregions of SERC, ownership of generation was heavily concentrated in a single entity, a vertically integrated utility that controlled transmission service. The second largest market share was less than 10 percent. Detail of the pattern of generation ownership in the regions without organized markets is provided in Appendix 3. Of the 12 regions examined, eight had moderate or high levels of concentration of generation ownership. Four (SPP, MAIN, ECAR and AZ-NM-SNV) exhibited low levels of concentration in generation ownership.

These observations are consistent with the pivotal supplier analyses[29] filed by jurisdictional entities in these regions. During 2003, the Commission issued orders in about 285 dockets finding that the applicant had passed, or was exempt from, the pivotal supply screen and authorizing continuation or new market-based rate authority. Approximately 140 dockets are pending before the Commission wherein the Commission will determine whether the applicant is a pivotal supplier in the market. An initial review indicates that many of these will not pass the supply margin assessment and, accordingly, will be found to be a pivotal supplier. This preliminarily indicates that during the assessment period there were regions without organized markets where the basic conditions necessary for achieving competitive performance were not in place.

Barriers to Entry

Independent power producers (IPPs) frequently objected to the operation of transmission services in regions without organized markets. These complaints alleged that the incumbent vertically integrated utilities used the administration of transmission services to discriminate against independent generators to the advantage of the incumbent's generation affiliates. Several types of discriminatory practices were mentioned in complaints, including:

- transmission provider favoring itself or its affiliate using available transfer capability (ATC) postings,

[27] Southern Co. is the control areas operator for one of the subregions of SERC. The other subregions of SERC are Entergy, TVA, VACAR and FRCC. OMOI has examined the Florida subregion (FRCC) as a region separate from the other SERC subregions.

[28] The Tennessee Valley Authority (TVA) is a public power entity. TVA, a wholly owned federal corporation, was established by Congress in 1933 to manage the navigation, flood control, power supply, water quality, recreation and land use of the integrated river system in the Tennessee Valley region. TVA generates and transmits power to local power distributors, such as municipalities, cooperatives, and federal agencies, and to large industries.

[29] A pivotal supplier is a power supplier whose capacity must be used to meet peak demand and whose capacity exceeds the market's supply margin. These analyses consider transmission constraints and obligations for retail service.

- discretionary dispatch to create constraints that block a competitor's scheduled power flows,
- preferential administration of energy balancing provisions to gain advantage over competitors,
- exploiting the native load preference to tie up transmission capacity and impede power flow schedules of competing generators,
- abuse of discretion in computing transmission reliability margins and capacity benefit margins and unnecessary delays on feasibility studies for transmission access.

Given the more limited market price transparency of the areas outside regions with organized markets,[30] it is difficult to assess the potential customer costs associated with these behaviors.

In conclusion, the market structures in regions with organized markets were relatively competitive during the assessment period, providing the basic conditions and support for the competitive performance of these markets. Load pockets in these regions were important exceptions to this general result. The market structures in eight of the 12 regions with bilateral markets provided significantly less support for competitive market performance, with control of both generation and transmission service concentrated in a single or a few vertically integrated entities. In such regions, the basic conditions and market structure for achieving competitive performance did not appear to be in place. Further analysis is needed and OMOI will continue to refine its analytical methods.

Prices, Market Activity, Congestion and Mitigation

Short-term Markets in Regions with Organized Markets

We observed that reported electricity prices in regions with organized markets[31] generally behaved in accordance with forces of supply and demand observed over the assessment period. It is important to note that market designs were not consistent across ISO-NE, NYISO, PJM, ERCOT and CAISO, though all five regions operated some form of real-time balancing markets. ISO-NE, NYISO and PJM also operated day-ahead energy markets. PJM, NYISO and ISO-NE operated LMP systems,[32] while CAISO and ERCOT used zonal systems. Prices, market activity,[33] congestion and mitigation during the assessment period are discussed broadly across regions below, followed by more detailed region-specific discussion.

Figure 17 and Table 6 show prices of representative price points for each region.[34] As evident from the table and figure, prices in organized markets averaged lower than in 2001. ISO prices in 2002 declined 8–15 percent, with the exception of CAISO markets, which declined 77 percent from 2001 levels. Milder weather, new generating capacity, inexpensive natural gas and improved hydroelectric conditions in the West contributed to the lower 2002 prices. Prices began to increase with the rise and spike of natural gas prices in late February and early March 2003 and remained at moderately higher levels (20–30 percent higher than in 2001) through mid-2003. Again, CAISO was an exception with first-half 2003 prices nearly 70 percent below 2001 levels. ERCOT was another exception with average first-half 2003 prices more than double the average 2001 level. All of the RTO and ISO markets and most other electricity markets in the country experienced the highest prices of the assessment period in February/March 2003 as the natural gas price spike was reflected in electricity prices. Comparison of prices across regions is difficult due to variations in product definitions and market structures, but the overall trend across these markets is evident.

During the assessment period, prices and trends for bilateral transactions as reported by ICE35 and *Megawatt Daily* are similar to those from the ISOs. Differences evident in Table 6 are in part due to data availability. For example, the average price in CAISO in 2001 as reported by ICE is significantly less than ISO and Megawatt Daily prices because the selected price point, NP-15, traded intermittently on ICE in 2001. Peak ISO prices are often higher than peak ICE and Megawatt Daily prices because they reflect real-time supply needs and transmission constraints, whereas ICE and Megawatt Daily prices reflect day-ahead expectations.

30 For further discussion, see the section on prices in regions without organized markets.

31 For a map of these regions, see Figure 8.

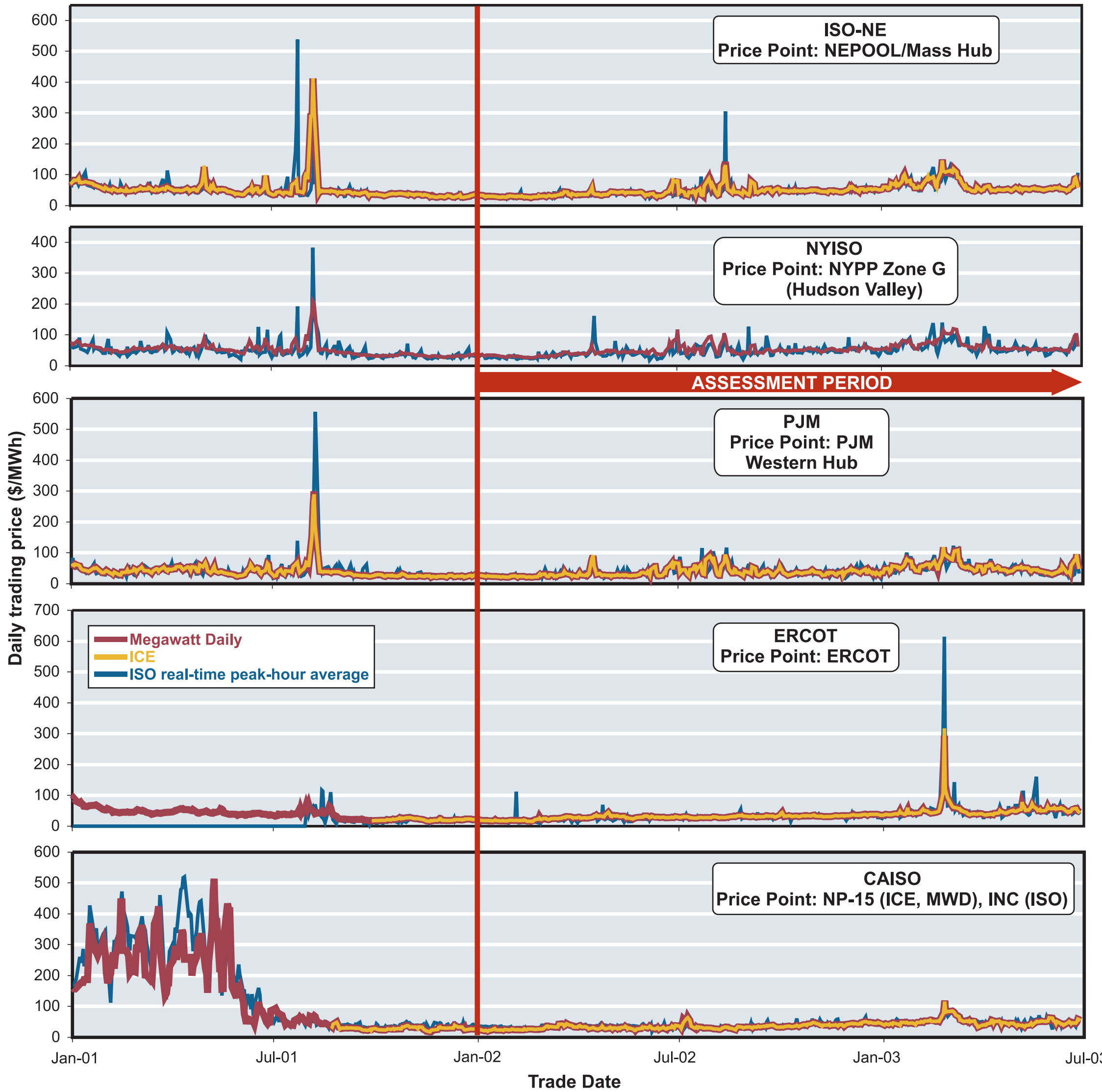
32 In NYISO and ISO-NE, loads paid zonal prices, which are averages of nodal LMPs within the zones.

33 To compare price, volatility and market activity across regions, OMOI selected one representative pricing point for each region, based on factors such as underlying liquidity and location. A map of price points is located in Appendix 6.

34 ISO prices were determined as follows: Real-time hourly prices during the peak hours in each region for each were averaged. The peak hours for each region are the hour ending 8 am through the hour ending 11 pm in the ISO-NE, PJM and NYISO markets and the hour ending 7 am through the hour ending 10 pm in CAISO and ERCOT. Peak days are considered to be Monday–Friday. CAISO considers Saturdays peak days, but they were left out of the chart so that NP-15 prices could be compared with the other regions.

35 During the assessment period, an additional source of bilateral price information emerged through reports from the IntercontinentalExchange (ICE), an online broker. ICE was launched in August 2000 as an internet platform for bilateral trades of energy, precious metals, weather and emissions. ICE began facilitating trading of energy on the platform in October 2000. Power products traded over-the-counter include physical electricity delivery at 18 power hubs for time periods ranging from same-day hourly power to full calendar years. ICE does not take title or participatory interest in any transaction.

Figure 17: Organized market power prices generally lower and more stable than in 2001.



Note: *Megawatt Daily* and ICE data are volume-weighted day-ahead peak prices. ISO data are averages of real-time hourly prices during peak hours. For more information, see footnote 34. NYPP Zone G (Hudson Valley) did not have an active market for day-ahead power on ICE. A map of price points is located in Appendix 6.

Source: Platts *Megawatt Daily*, ICE, ISO-NE, NYISO, PJM, ERCOT and CAISO.36 Analysis and graphic by OMOI.

[36] NP-15 prices are for CAISO incremental (INC) energy in the North of Path 15 zone as recorded on CAISO's OASIS. NP-15 data do not include prices CAISO paid for out-of-sequence (OOS) and out-of-market (OOM) energy. In 2001, the market-clearing price was limited by various soft caps, including a soft cap of $150/MWh, January through April 2001. Bids were accepted above the soft cap and paid as-bid subject to cost justification. In January 2001, the overall monthly average real-time energy price, including OOM and OOS, was $290/MWh. The as-bid and OOM purchases diminished substantially over the first half of the year and, by December 2001, the overall monthly average real-time INC energy price was $57/MWh. (CAISO Department of Market Analysis, Market Analysis Report, Feb. 16, 2001 through Feb. 1, 2002.)

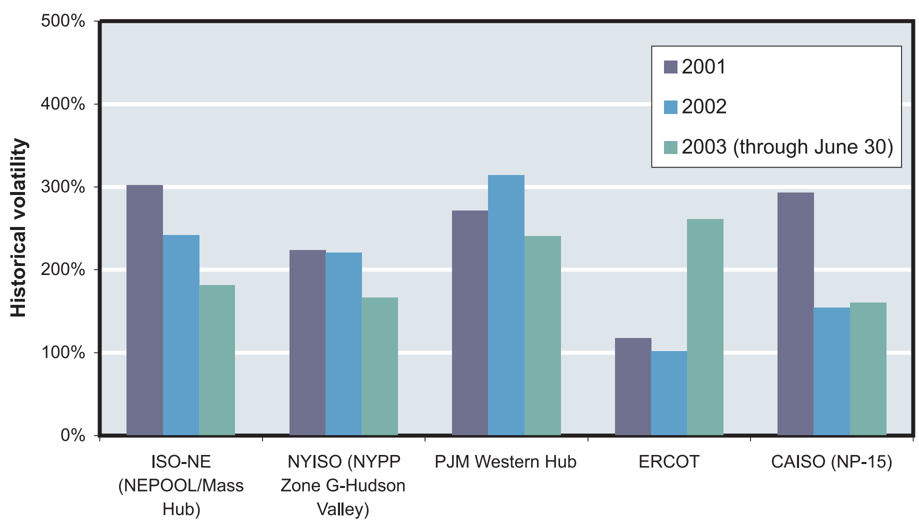
Table 6: Electricity prices in regions with organized electricity markets.

Price ($/MWh)		2001			2002			First half of 2003			First half of 2003 (adjusted***)		
		Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean
ISO-NE	ICE	26.17	130.00	47.16	25.13	130.80	43.24	46.00	146.20	65.86	46.00	100.05	61.83
	MWD	26.41	411.60	52.26	25.05	141.50	43.40	46.33	149.22	65.40	46.33	120.25	61.28
	ISO	21.93	537.92	49.18	23.29	305.06	41.96	43.60	128.34	63.66	43.60	124.55	60.05
NYISO [NYPP Zone G (Hudson Valley)]	ICE	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	MWD	27.29	209.00	51.54	25.50	116.53	46.62	45.44	140.00	66.88	45.44	120.00	60.60
	ISO	21.40	382.71	48.72	18.57	297.33	44.75	33.27	139.01	63.06	33.27	137.89	60.20
PJM Western Hub	ICE	19.99	288.83	40.46	21.14	116.02	35.86	30.43	118.46	54.17	30.43	108.53	51.10
	MWD	20.21	299.60	40.56	21.09	115.57	35.86	30.33	117.79	54.06	30.33	108.99	50.93
	ISO	15.84	556.87	43.20	16.44	149.04	37.20	21.97	122.64	52.75	21.97	111.98	49.91
ERCOT	ICE*	17.00	75.00	30.75	15.26	45.55	29.12	36.59	316.25	52.76	36.59	78.00	48.07
	MWD	16.59	91.44	39.15	16.57	45.57	29.25	36.50	293.00	52.34	36.50	74.11	48.07
	ISO**	3.68	116.60	24.42	10.12	111.23	26.74	26.59	615.13	57.97	26.59	159.91	47.84
CAISO [NP-15 (ICE, MW), INC (ISO)]	ICE*	17.52	435.00	71.46	19.24	63.68	33.47	32.96	115.72	49.83	32.96	67.01	47.01
	MWD	17.74	513.75	134.56	19.20	65.17	33.60	32.93	118.62	49.88	32.93	72.79	47.32
	ISO	13.78	519.60	157.92	18.47	65.79	36.37	25.50	86.96	51.45	25.50	72.96	49.45

Notes: *Traded intermittently. **Data begin 7/31/2001. ***Excludes 2/24–3/9 (period of February/March 2003 natural gas price spike). *Megawatt Daily* (MWD) and ICE data are volume-weighted day-ahead peak prices. ISO data are averages of real-time hourly prices during peak hours. For more information, see footnote 34.

Source: Platts *Megawatt Daily*, ICE, ISO-NE, NYISO, PJM, ERCOT and CAISO. See footnote 36 for details on CAISO.

Figure 18: Organized market volatility declines.



Note: Data are day-ahead on-peak prices. Annualized historical volatility is calculated as the annualized standard deviation of logarithmic returns, log (pricet /pricet-1), where standard deviation is based on all on-peak days (weekdays excluding NERC holidays) during the period.

Source: Platts *Megawatt Daily*. Analysis and graphic by OMOI.

Table 7: Electricity volumes transacted in organized markets.

000 GWh (cumulative)	Day-ahead market			Real-time market		
Region	2001	2002	2003 thru 6/30/03	2001	2002	2003 thru 6/30/03
ISO-NE	(1)	(1)	11 (2)	30	41	8 (2)
NYISO	161	162	77	3	1	2
PJM	42	104	60	57	119	67
ERCOT (3)	N/A	N/A	N/A	1	7	5
CAISO (4)	N/A	N/A	N/A	14	2	1

Notes: (1) Day-Ahead Market initiated March 1, 2003. (2) Only includes transactions from March 1 to June 30. In addition, after March 1, 2003 the real-time market was only a residual market. (3) ERCOT does not have a day-ahead market. Real-time energy balancing market began July 31, 2001. Real-time market data are for real-time Balancing Up energy. (4) CAISO does not have a day-ahead market. Real-time market data are for Incremental (INC) energy.

Source: ISO websites and ISO MMU response to OMOI data requests.

As shown in Figure 18, price volatility generally declined since 2001, except for the large increase in ERCOT due to a steep price spike in late February 2003 in the region. In comparison, the volatility of physical natural gas prices increased during the assessment period (see Figure 53), but at the 70 percent level, was significantly below the 150–250 percent levels experienced in organized electricity markets. In addition, price volatility in organized markets was lower than levels experienced in regions without organized markets (see Figure 27).

Market activity data offer information about liquidity and participation. As shown in Table 7, participation in or RTO real-time balancing markets and day-ahead markets was robust during the assessment period.

The apparent decline in volumes traded in the CAISO market from 2001 to 2002 stems from unusually high volumes traded in the first five months of 2001, which was during the energy crisis. This high volume of trading was conducted by California Energy Resources Scheduling (CERS), a state entity that purchased energy in real time to meet the net short needs of California's utilities—primarily Pacific Gas & Electric (PG&E) and Southern California Edison (SCE)—when they could no longer make the purchases or contract on their own due to insolvency.[37] Thus the 2002 volumes, which were less than approximately 5 percent of system load,[38] reflect a level of trading more consistent with the design of the CAISO's imbalance market.

The decline in volumes in the ISO-NE real-time market is due to a market-design change. In March 2003, a day-ahead market began, making the real-time market a residual market.

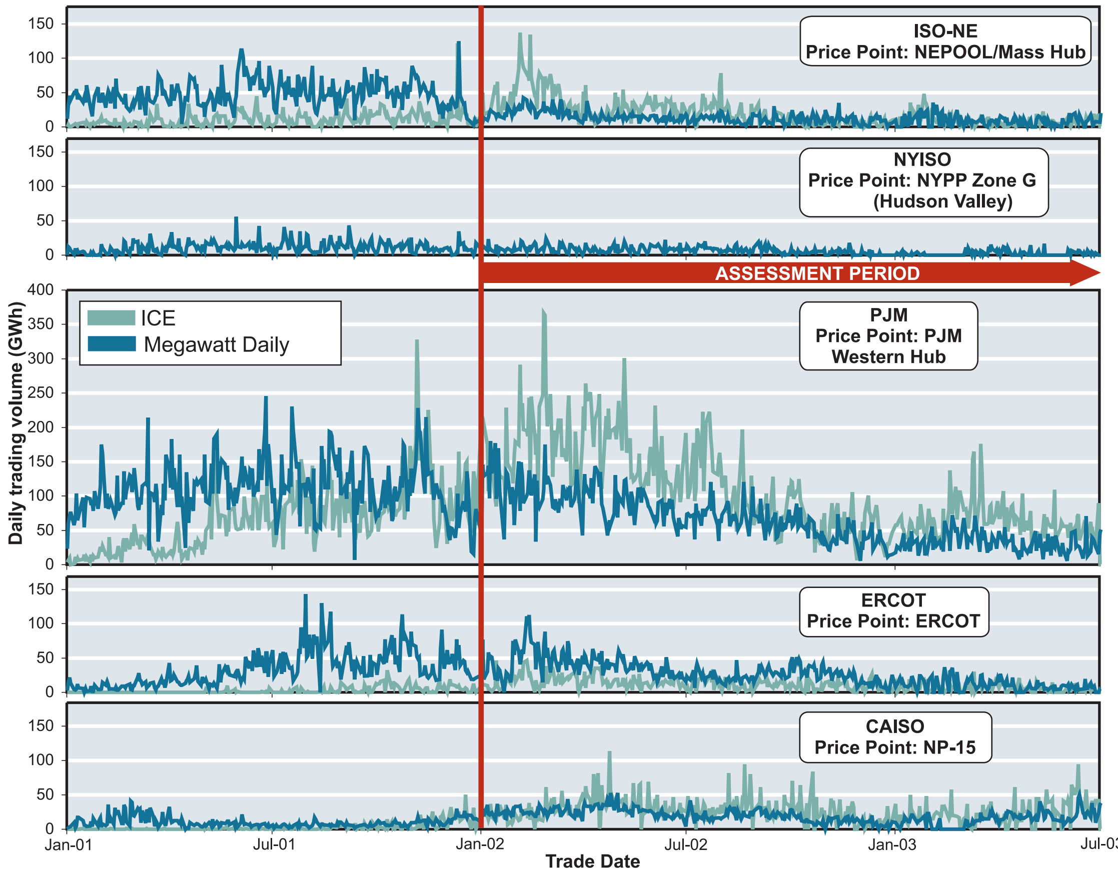
The decline in real-time market volumes in NYISO between 2001 and 2002 should be viewed in the context of the small and variable real-time market share. During the 18-month assessment period, monthly real-time market shares ranged between negative 1.6 percent and positive 3.6 percent. This variability reflects the primary function of the real-time market: to balance differences between day-ahead expectations and actual consumption. Day-ahead forecasts of consumption commonly have errors of plus or minus 2 percent. These are likely to be the major cause of variability in real-time volumes. Another factor may have been the small decline in consumption between 2002 and 2003, due to weather and the economic downturn in the region.

It is also possible that, as the market matured, NYISO participants became more comfortable putting most or all of their load into the day-ahead market rather than the real-time market. Two trends lend support to this: the narrowing of wide divergences between hour-ahead advisory prices and real-time prices, and the introduction of virtual transactions in November 2001 that tended to limit the differences between day-ahead and real-time prices (and allow hedging). However, it is likely that typical variations in real-time volumes due to forecast error are a more important explanation of the decline in market activity than increased confidence in the day-ahead market.

[37] PG&E and SCE became insolvent during the energy crisis in early 2001, while San Diego Gas & Electric did not.

[38] CAISO, 2001 Annual Report, p. 17 (www.caiso.com/docs/09003a6080/13/f0/09003a608013f05b.pdf)

Figure 19: Reported bilateral trading volumes in organized markets decline.



Note: ICE did not report trade volumes for day-ahead power for NYPP Zone G (Hudson Valley). *Megawatt Daily* volumes reflect on-peak transactions surveyed by the trade publication. *Megawatt Daily* data have been modified to make them comparable to ICE data. *Megawatt Daily* volumes have been multiplied by 16 to convert from a 16 peak-hour MW contract into a MWh. Final volumes are converted to GWh. In addition, since *Megawatt Daily* volumes include both buy and sell sides of transactions and ICE volumes include only the sell side of transactions, ICE volumes were doubled.

Source: Platts *Megawatt Daily* and ICE. Analysis and graphic by OMOI.

Table 8: Reported bilateral trading volumes in regions with organized markets.

Average daily volume (GWh)	ISO-NE		NYPP ZG		PJM		ERCOT		NP-15	
	MWD	ICE	MWD	ICE	MWD	ICE	MWD	ICE	MWD	ICE
2001 (full year)	48	12	11	N/A	111	66	34	7	10	7
2002 (full year)	14	26	8	N/A	77	129	34	15	21	31
2003 (first half)	10	11	3	N/A	32	66	12	8	17	29

Note: ICE did not report trade volumes for day-ahead power for NYPP Zone G (Hudson Valley). *Megawatt Daily* volumes reflect on-peak transactions surveyed by the trade publication. *Megawatt Daily* data have been modified to make them comparable to ICE data. *Megawatt Daily* volumes have been multiplied by 16 to convert from a 16 peak-hour MW contract into a MWh. Final volumes are converted to GWh. In addition, since *Megawatt Daily* volumes include both buy and sell sides of transactions and ICE volumes include only the sell side of transactions, ICE volumes were doubled.

Source: Platts *Megawatt Daily* and ICE.

Data from ICE and *Megawatt Daily* give some insight into bilateral market activity in each region, but contain only a subset of short-term bilateral contracts, those conducted on ICE or reported to *Megawatt Daily.* Depending on the relative size of a region's reliance on long-term bilateral transactions and short-term ISO or RTO transactions, the overall and relative size of a region's short-term activity may not be accurately represented by volumes of short-term bilateral transactions. For example, Figure 19 and Table 8 indicate that activity in New York Power Pool (NYPP) Zone G (Hudson Valley) was small compared to other regions. However, this is consistent with data from EQR that indicate short-term bilateral deals were a relatively small part (19 percent) of reported transactions in New York generally, whereas short-term deals conducted through the ISO markets are 52 percent of total reported transactions.39 This is in contrast to CAISO, where short-term deals conducted through the ISO accounted for a small percentage (1 percent) of total transactions and short-term bilateral deals accounted for a large percentage (76 percent).

Despite data limitations, it is clear that trading generally declined during the assessment period due to the financial deterioration of the energy market and decline of creditworthy participants. This limited risk management options for market participants and could indicate inefficient market pricing.

Transmission congestion affected electricity prices to varying degrees in each region. Congestion can effectively prevent a distant but lower-priced generator from providing more energy at a particular point, forcing a higher priced generator to be used. Locations with chronic congestion, load pockets, have insufficient generation capacity within the pocket compared to peak demands and the area's transmission network is limited in its ability to import additional, often lower-cost resources from outside the pocket.

LMP systems, which were used in ISO-NE, NYISO and PJM, contain a congestion component that explicitly prices the cost of congestion. When there is no transmission congestion, the congestion price component is zero and all locational prices in the region are equal, except for variation that reflects marginal losses.[40] When transmission facilities are constrained, the marginal price at one location—the cost of the next increment of energy supplied there—differs from other locations that are more or less affected by the constraints, and the congestion price component reflects the cost differences. ERCOT and CAISO used zonal systems and while zonal systems reflect price differentials due to congestion, the differential is most clearly reflected in an LMP system.

Congestion costs during the assessment period varied across regions and cannot be directly compared due to differences in market design and congestion cost accounting. For example, congestion costs in ISO-NE totaled $139 million during the assessment period.[41] However, from January 2002–March 2003, prior to the introduction of its LMP system, this figure may have included costs for re-dispatch not associated with relieving a constraint. NYISO's $793 million in congestion costs during the assessment period comprises a significant amount of total energy costs—19 percent when compared to total invoices.[42] These costs are due primarily to constraints on five interfaces in or near the heavily congested New York City region. Congestion costs in PJM were $430 million in 2002, up from $271 million in 2001.[43] Congestion in PJM is different from congestion found in other markets because it tended not to occur on the same transmission lines frequently or only during periods of high load as in other markets, but rather throughout the region and often during off-peak hours. The increase in congestion costs in PJM is primarily due to the addition of PJM West, which brought in low-cost coal-fired power that lowered prices in the western part of PJM but did not affect the eastern part due to constraints in the system. California reported relatively low congestion costs—$53 million in interzonal congestion costs during the assessment period and $10 million in intrazonal congestion costs in 2002 only.[44] Since CAISO is a zonal system, congestion costs are made explicit between CAISO's three zones, not at multiple locations within zones. As a result, CAISO underestimates intrazonal congestion costs. Data on congestion costs for ERCOT were not available.

Finally, mitigation procedures and frequency of use varied across regions. Mitigation has important effects on both short- and long-term prices in electricity markets. Market operators use mitigation procedures to prevent the exercise of market power. However, if the mitigation is not warranted because there is no exercise of market power, the mitigation suppresses prices signals, resulting in diminished investment in needed infrastructure. That, in turn, results in higher prices in the longer term. Price suppression has particularly problematic effects in load pockets, areas in need of infrastructure investment. Mitigation procedures and frequency of use during the assessment period are summarized by region in Table 9. More detailed discussion of mitigation is included in the regional analyses below.

39 Derived from FERC EQR, Fourth Quarter 2002 through Second Quarter 2003. For more information on EQR data used in this report see footnote 5.

40 The inclusion of marginal losses can result in significant LMP variation across regions. For example, in NYISO, marginal loss factors (i.e., the marginal loss component of LMPs expressed as a percentage of the energy component of the reference bus LMP) can vary as much as 20 percent for a power transaction from Western NY to NYC/Long Island. Both NYSIO and ISO-NE include marginal losses in their LMP calculation. LMPs in PJM do not.

41 ISO-NE response to data request and 2002 Annual Market Report.

42 NYISO response to data request.

43 PJM, 2002 State of the Markets.

44 CAISO, 2002 Annual Report on Market Issues and Performance.

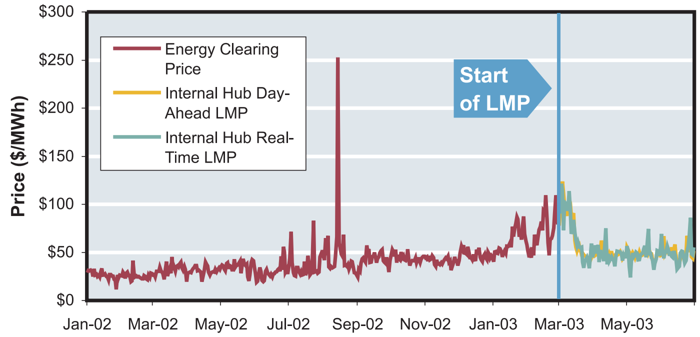
Table 9: Mitigation procedures by region.

Market	Type	Where it applies	Calculation	Frequency
*ISO-NE	Bid Cap	System	$1,000	
	Local (PUSH)	Designated Congestion Areas (DCAs)	Units are subject to a conduct and impact test. For units with less than a 10% capacity factor, the reference and the threshold are the sum of the unit's fixed and variable costs. If the unit fails both conduct and impact tests and behavior is unexplained, the ISO can substitute a reference price for the faulty bid or offer.	No Peaking Unit Safe Harbor (PUSH) bids have been mitigated
	Pivotal Supplier**	System-wide during uncon-strained hours	Energy bid exceeds reference price by 300% or $100. Other thresholds exist for no-load, regulation and other types of offers. If unit fails conduct and impact tests and behavior is unexplained, ISO can substitute refer-ence price for faulty bid.	This provision became effective 7/1/2003
	Local (RMR)	Unit specific	Cost of service	No RMR bids have been mitigated
	Other units during con-strained hours	System-wide during con-strained hours	Energy bids exceed reference price by 50% or $25. This is more stringent than pivotal supplier threshold. Other thresholds exist for start-up and no-load. If the unit fails both conduct and impact tests and behavior is unexplained, the ISO can substitute a reference price for the faulty bid or offer.	4 instances
NYISO	Bid Cap	System	$1,000	
	Conduct and Impact (AMP)	System-wide	Reduced to reference price if (a) bid exceeds reference level by 300% or $100 and (b) bid would raise price by 200% or $100 (different thresholds apply to reserves and other bid parameters).	No bids mitigated between 1/1/2002 and 6/30/2003
	Local (In-city)	New York City	DA: reduced to reference price when 7% higher than INP#2 bus. RT: reduced to reference price when load pocket congested, if bid is 300% or $100 above reference level and proxy impact exists.	DA: about 50% of unit hours; RT: about 20% of unit hours
PJM	Bid Cap	System	$1,000	
	Local	RMR units in con-strained areas	Pre-determined Variable Cost Plus 10%	The average number of units mitigated in any month did not exceed 1%. However, some affected units had significant hours of mitigation.
ERCOT	Bid Cap	System	$1,000	
	Competitive Solution Method	System	Evaluates market conditions as a whole. The conditions for a market to pass are (a) total bids to provide a service must amount to at least 115% of what ERCOT needs, and (b) the market-clearing price must not be set by a pivotal bidder.	No bids mitigated between 1/1/2002 and 6/30/2003***
	Local	Constrained areas	Three or more suppliers required for Market Solution. In case of less than three suppliers, out-of-merit (OOM) dispatch using generic cost based offers that vary by type of unit.	Market Solution rare for constrained areas. Approach suspended after sudden increase in costs in June 2003
CAISO	Bid Cap	System	$250 (soft cap)	
	Bid Cap	DEC Energy	- $30 (soft cap)	
	Conduct and Impact	Real-Time	Dispatched in Hour Ahead Market when predicted prices exceed $91.87 Conduct test = bid over 200% of Reference or $100 over Reference Impact test = bid increases price by lesser of 200% or $50	1582 bids failed the Conduct Test between 1/1/03–11/25/03, no Impact Test failures, no mitigated bids
	Local	RMR contracts	Condition 1 Units: Market Based, Condition 2 Units: Cost Based	
	Local	Constrained Area	If bid exceeds the zonal price by lesser of 200% or $50, it is reset to higher of zonal price or the unit's reference price. There is no separate impact test.	

Notes: Reliability Must Run (RMR) generating units are units identified by the ISO as necessary for operational or reliability reasons and must run, regardless of economic considerations. *New England had other types of mitigation mechanisms dealing with physical withholding, uneconomic production and reliability must run (RMR) agreements. **A pivotal supplier is any participant whose aggregate energy supply offer is greater than the NEPOOL supply margin. The NEPOOL supply margin is the total energy supply offer for each hour less total system load, including net imports and operating reserves. ***A bid of $990 was made in late February 2003.

Source: OMOI.

Figure 20: ISO-NE prices increase.



Note: Daily load-weighted average energy price.
Source: ISO-NE. Analysis and graphic by OMOI.

Variations in price, market activity, congestion and mitigation by region are important. We consider these variations over the assessment period in each of these markets separately.

ISO-NE

On March 1, 2003, New England replaced its uniformly priced, real-time market with day-ahead and real-time markets and LMP. Both the former and the current market's responses to variations in demand and input prices are what one would expect from a well-functioning market. As shown in Figure 20, prices were relatively stable at about $30/MWh in the first half of 2002 due to mild weather and stable input prices.

Successive heat waves in summer 2002 generated a series of historic peak demand days and corresponding price spikes. In the fall, prices stabilized again but at slightly higher levels, around $43/MWh. During the winter months, prices rose to a monthly average of well over $60 as natural gas prices rose. Over the period, Jan. 1, 2002 through Feb. 28, 2003, there were eight instances—all during summer 2002—when prices rose above $200.

Since the start of the new market, average day-ahead and real-time prices were in the $52/MWh range. For the most part, day-ahead LMPs were higher than real-time LMPs and, as expected, real-time LMPs were more volatile than day-ahead LMPs due to unforeseen intra-day events such as outages, deviations between forecast and actual load and changes in operating conditions. Since March 1, 2003 LMPs exceeded $200 in 21 day-ahead hours and 37 real-time hours,[45] mainly due to a combination of cold temperatures, high gas prices and virtual bidding[46] in the first half of March 2003—and later due to various facilities outages/failures and congestion.

The most heavily congested areas in New England were Southwest Connecticut and the Boston area. The zones that include these congested areas exhibited higher congestion cost components than zones such as Maine, which was an export-constrained area (for a map of zones, see Figure 69). Although congestion was not significant in Vermont,[47] reliability was a critical concern, particularly in Northwest Vermont, due to increasing loads, weak links with the main transmission system and a lack of power plants in the area.[48] Both Connecticut and Vermont currently have transmission projects in the review/siting process designed to alleviate reliability concerns and congestion.

[45] Note that the text refers to hourly prices and Figure 20 shows daily average prices. In addition, the figure shows hub prices only while the text refers to the prices across the load zones (eight zones and one hub) in ISO-NE.

[46] Virtual bids are included in the day-ahead supply stack. As a result, they can make a node appear more congested in the case of an incremental bid (an offer to sell) or less congested in the case of a decremental bid (an offer to buy).

[47] ISO-NE's economic dispatch software operates by selecting a reference location (not necessarily physical location) where congestion costs and losses are assumed to be zero. The price at this reference location is used as the system wide energy component of the LMP. Ignoring the effect of losses, the congestion component of the LMP for each pricing node (zone) is calculated by subtracting the system-wide energy component price from the LMP at the node (zone). As a result, nodal (zonal) congestion components can be either positive or negative. The LMP is always the cost to serve an additional increment of load. Thus, the selection of a reference location doesn't change the LMP, although the selection can create somewhat counterintuitive negative congestion component of the LMP. A high positive congestion LMP component indicates that the lines in that region are more heavily congested than in regions with lower congestion components. Conversely, lines in areas with negative congestion components tend to be more lightly loaded. However, there is not necessarily a linear relationship between the LMP and the loading of the line (Source: ISO NEWS, ISO-NE, Apr. 18, 2003).

[48] ISO-NE, "RTEP03 Executive summary and Overview," Second Draft of the 2003 Regional Transmission Expansion Plan (RTEP03). Sept. 12, 2003. Only about 15 percent of load in Northwest Vermont is met with local generation.

Table 10: Congestion cost components in ISO-NE zones.

Hub and load zone name	Average real-time congestion component (March –June 2003)
Connecticut	$0.34/MWh
Northeastern Massachusetts (including Boston)	$0.16/MWh
Southeastern Massachusetts	$0.07/MWh
Rhode Island	$0.06/MWh
Western/Central Massachusetts	$0.05/MWh
ISO-NE Hub	$0.04/MWh
Vermont	- $0.08/MWh
New Hampshire	- $0.40/MWh
Maine	- $1.20/MWh

Source: ISO-NE

New England's hub is a set of pre-defined, relatively unconstrained nodes in Massachusetts and the ISO-NE hub price is the simple average of the LMPs at the applicable nodes. In practice, however, prices at the hub were fairly volatile due to imbalances between incremental offers and decremental bids. The increased volatility made risk management more difficult, reducing liquidity. Possible solutions being considered by NEPOOL are reconfiguring or redefining the hub.[49]

To maintain or improve system reliability in load pockets, the ISO has the authority to negotiate Reliability Must Run (RMR) agreements. RMR agreements are a mechanism for insuring that high priced units that operate at low capacity factors are able to recover their costs and, thus, remain in-service and available to the ISO. The difference between the amount that is paid to the generator under the RMR contract and the energy clearing price is recovered from the market participants in the form of uplift.[50]

On June 1, 2003, New England implemented a temporary mechanism called the Peaking Unit Safe Harbor (PUSH) offer rules. The goal of PUSH is to increase opportunities for high cost but seldom run units in designated congestion areas (DCAs)[51] to recover their fixed and variable costs through a market mechanism and to produce signals for investment through higher LMPs in these areas during periods of scarcity. Under PUSH, generators in DCAs with a capacity factor[52] of 10 percent or less in calendar year 2002 can submit energy offers up to their marginal energy costs plus their levelized fixed costs, without the imposition of mitigation measures.[53]

Recently, ISO-NE issued a report on PUSH's performance that covers a portion of the assessment period.[54] The report finds that PUSH enabled greater cost recovery than could have occurred under the previous mitigation rules, but that it is unlikely that the PUSH units will be able to recover all of their fixed costs. One of the reasons for this expectation is that the PUSH unit's levelized fixed costs are determined using 2002 data and the unit's output in 2002. Because of overall milder temperatures and hence lighter loads, the PUSH unit's capacity factors in 2003 were less than in 2002. The average capacity factor for units receiving PUSH treatment during the summer of 2003 was approximately 35 percent of the capacity factor of those same units during the summer of 2002. The report also finds that the PUSH units were primarily dispatched out of merit order solely to provide reserves, not as a part of the system-wide dispatch. The result is that the PUSH units seldom set the electric clearing price, the anticipated price signal for investment. The ISO is required to replace PUSH with a locational installed capacity (ICAP) requirement, deliverability requirements or similar modifications to the existing ISO-NE capacity market no later than June 1, 2004.

The ISO's market monitoring group is charged with evaluating economic withholding in the New England electricity market. From Jan. 1, 2002, until March 1, 2003, the Market Monitoring Group (MMG) performed this evaluation under Market Rule 17.[55] From March 1 forward, the MMG performed this evaluation under Appendix A of Market Rule 1. The rules are similar; the MMG imposes mitigation if:

- a participant exceeds a specified conduct threshold relative to an established conduct history,

49 NEPOOL, Hub White Paper, Hub Analysis Working Group, Participants committee, Agenda Item #4, Oct. 29, 2003.

50 Uplift generally refers to costs allocated to all market participants in a given region or market and not charged directly to the participant that caused the cost to be incurred. Some categories of charges that may be allocated to uplift are ancillary services and out-of-merit dispatch costs.

51 DCAs in New England are Northeastern Massachusetts/Boston, Connecticut and Southwest Connecticut. These areas are characterized by the frequent need to operate generating units out of merit order to satisfy reliability needs, and by a chronic need for additional infrastructure.

52 Capacity factor is defined as the percentage of actual unit output over the specified time period relative to total possible output over the time period.

53 Non-PUSH and RMR units may bid up to their marginal cost of fuel and operating expenses.

54 ISO-NE, Review of PUSH Implementation Rules, Docket No. ER03-563-002, filed with the Commission on Dec. 4, 2003.

55 The use of conduct and market impact tests did not apply to physical withholding and mitigation of ICAP resources in Market Rule 17.

- that conduct results in a significant price effect as modeled using appropriate tools, and
- the conduct is unexplained.

However, the criteria for evaluation and mitigation differ under each set of rules. Additionally, each rule contains specific general or first level mitigation procedures[56] and mitigation procedures applicable to congested areas. The current Appendix A mitigation procedures are summarized in Table 9.

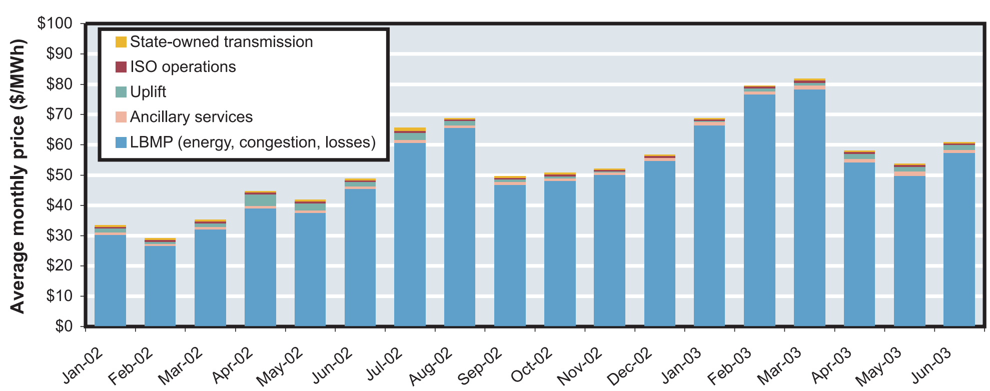
Under Market Rule 17, the ISO did not implement general mitigation during the Jan. 1, 2002 to March 1, 2003, period. However, mitigation was imposed frequently in transmission constrained areas. Almost every day a unit or units were mitigated under the complicated mitigation formulas in Market Rule 17. Appendix A of Market Rule 1 provided no authority for general market power mitigation through June 30, 2003, though this authority was granted in July 2003. Congestion mitigation was imposed four times under the new market rules between March 1, 2003 and June 30, 2003. Due to bidding that exceeded thresholds, mitigation was imposed three times during operating reserve evaluation and once during real-time market operations. In each case, the participants changed their behavior after the mitigation event to avoid future risk of mitigation.

The MMG also has responsibility to investigate physical withholding under both market rules. Although many units were investigated for physical withholding under Market Rule 17, which required submission of plant operator logs, the MMG determined that no physical withholding had occurred. Physical withholding was investigated under Market Rule 1 on days between March 1 and June 30, 2003. MMG personnel physically inspected a generating facility in late-June as part of an investigation of physical withholding. In no instance did the MMG determine that physical withholding had occurred.

NYISO

The average 2002 NYISO price (including ancillary services) was $49.77/MWh, down from $51.39 the previous year. The average 2003 price through June was $67.43, compared to $39.06 for the same period in 2002 and $55.95 in 2001. These prices reflected changes in the price of natural gas, which was often the marginal fuel in New York. Day-ahead prices in Zone G (Hudson Valley) never exceeded $200 from July 2002 through June 2003, in marked contrast to the previous 12 months when day-ahead prices exceeded $1,000 (due to hot weather on Aug. 9 and 10, 2001, when New York set all-time load records.) Average monthly prices are shown in Figure 21.

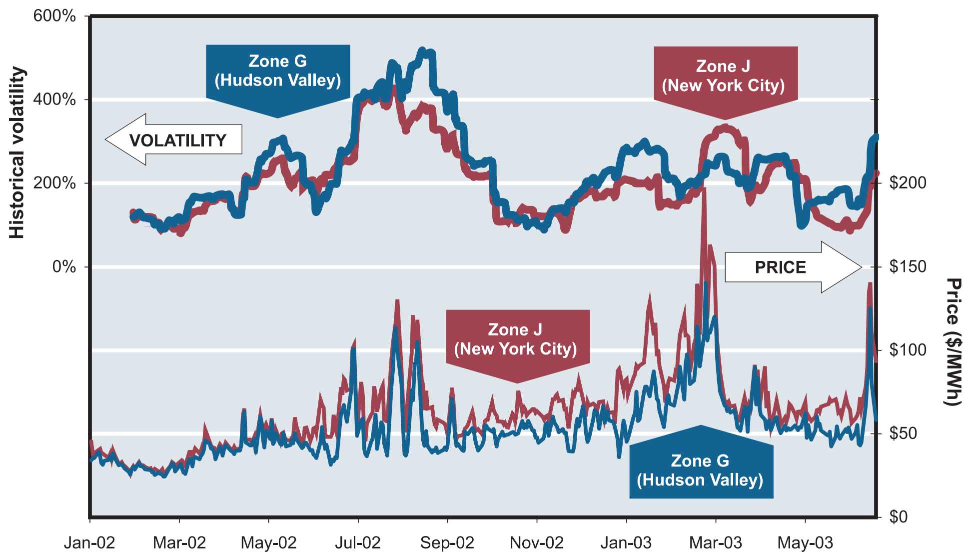
Figure 21: NYISO average monthly prices increase.



Note: Does not include ICAP costs.
Source: NYISO. Analysis and graphic by OMOI.

56 The first level of mitigation occurs when there are no transmission constraints.

Figure 22: NYISO day-ahead volatility peaks in summer 2002.



Note: Data are from average on-peak prices. Historical volatility is calculated as the standard deviation of logarithmic returns, log ($price_t$ /$price_{t-1}$), where standard deviation is based on the previous 21 on-peak days (weekdays excluding NERC holidays).

Source: NYISO. Analysis and graphic by OMOI.

NYISO day-ahead prices were most volatile in July through September 2002, when volatility ranged between about 300 percent and 500 percent. In the two six-month periods ending June 30, 2002 and June 30, 2003, volatility levels were similar, about 100 percent to 300 percent. Real-time prices continued to be more volatile than day-ahead because they reflect events that occur after the day-ahead market has closed. In the bilateral market, prices for Zone J (New York City) during summer 2003 were less volatile than in the previous summer. Spring 2003 bilateral prices were more volatile than the previous spring, probably as a result of volatile natural gas prices. NYISO day-ahead prices and their historical volatility are shown in Figure 22.

Prices in NYISO-operated energy markets responded as expected to weather-driven load and to fuel prices. One exception occurred during an April 2002 heat wave that increased load at a time when some generation was out for seasonal maintenance. NYISO's forecasting software issued an inaccurate load forecast on two days, contributing to a brief spike in real-time prices (not displayed in the day-ahead prices in Figure 22). Differences between NYISO's advisory hour-ahead prices and real-time prices (a significant problem in the past) were markedly reduced during the assessment period.

Like ISO-NE, NYISO's locational prices contain an explicit congestion component. NYISO estimates that constraints at five transmission facilities had the largest congestion effects on prices[57] in its market; four of those are within or lead to the New York City metropolitan area. These facilities were constrained between 16 and 59 percent of the time during the assessment period. Transmission constraints were thus limiting competition in the city by limiting customer access to multiple sellers, necessitating the use of more expensive local in-city generation, and raising prices. NYISO calculates that congestion[58] during the period added $793 million to the price of energy in the state. Based on NYISO invoices of about $4.25 billion[59] during the same period, congestion amounted to 19 percent of the costs borne by NYISO customers statewide.

NYISO's tariff defines conduct which may be mitigated or penalized, types of mitigation that may be imposed and thresholds for imposing them.[60] NYISO devised and implemented an automated bid review and mitigation process (AMP) with two potential advantages. First, AMP allows prices to reflect mitigation as the prices are computed, rather than after-the-fact as was previously the case. Second, AMP applies mitigation in a way designed to avoid mitigating high prices due to genuine scarcity. The process is described in

57 Exact congestion costs for each facility or for the group of five facilities were not available.

58 Losses are not included in this amount.

59 NYISO July 2003 Monthly Report, p. 11-C.

60 NYISO Tariff, Original Volume No. 2, Attachment H (eff. July 3, 2001).

more detail in Table 9. No bids were mitigated with the AMP process during the period of this report.[61]

Unlike the rest of the state, New York City experiences mitigation routinely. Because of concentration in the New York City generation market, NYISO manages a separate set of mitigation rules there. In the day-ahead market, generation bids were mitigated about half of the time[62] to a fuel-adjusted reference price; the process is similar to mitigation in place before NYISO operations began.

Within New York City are several sub-areas where operating constraints create congestion, raising concerns about market power for generators within them. In mid-2002 NYISO's real-time software began modeling nine such load pockets. Under the New York City-specific mitigation procedures, when congestion (as measured by price differences across the load pocket interfaces) reaches pre-set levels, the MMU reviews generator bids to determine if they exceed reference levels. If so, and if certain other conditions relating to the unit's effect are met, the MMU mitigates the generator's bids to the reference level.[63] Prices were mitigated this way about 20 percent of the time in the real-time market in New York City.

Mitigation can distort market outcomes, thus NYISO has taken measures to offset some of the price suppressing effects of mitigation in New York City. For example, the load pocket modeling described above has the effect of raising prices for some generators in New York City. Before the modeling began, the cost of running generators to serve load pockets was not included in locational prices but was charged as uplift instead. Excluding these costs from the locational price tended to suppress prices in New York City because needed generators were often costly. Now such costs (about $75 million in 2002[64]) are explicitly reflected in locational prices, so they send a more accurate signal to potential entrants.[65] Recent design changes to allow prices to better reflect scarcity are intended to improve price signals.[66] As another incentive to build new capacity, NYISO's mitigation plan sets a more generous reference price for new generators in the state during their first three years of operation. Their reference price is the 12-month average peak price in their zone, if higher than the result of the reference price formula.[67]

PJM

As a general matter, PJM prices responded to load, capacity and fuel input prices as expected. A combination of adequate supply system-wide, lower fuel prices and a lower level of economic activity kept price levels in 2002 generally lower than in 2001. As in the rest of the Northeast, an unseasonably warm winter and moderate natural gas costs kept average prices during the assessment period through March 2002 generally below $31/MWh. An April 2002 heat wave caused unusually high loads at a time when some generation was unavailable because of seasonal maintenance, causing brief price increases. Hot weather in July and August 2002 again drove prices briefly to high levels. Late in the winter of 2002/03, high fuel prices contributed, along with high loads because of the weather, to high electricity prices. However, PJM was not affected as severely as other regions by high gas prices and gas shortage because it is less reliant on gas-fired generation, has better pipeline options and is closer to gas storage areas. The prices for PJM's day-ahead market track very closely with comparable prices for similar products in the bilateral market, such as peak period, day-ahead energy delivered to the Western Hub.

As expected in a well-functioning market, summer prices in PJM were sensitive to load, particularly during the summer months, as shown in Figure 23. During the assessment period, these price increases at the time of the highest loads were of short duration and were more moderate than in prior years due to lower fuel prices, capacity additions and the addition of Allegheny Power System generation in the PJM dispatch. During the first six months of 2003, however, fuel price increases worked to reverse that trend.

Figure 24 shows that day-ahead price volatility was consistently lower than the real-time volatility during the same period. The relationship between real-time and day-ahead volatility is expected and reasonable because real-time prices follow the variations in actual load and supply, particularly outages, more closely. Alternatively, day-ahead markets tend to rely on typical rather than unexpected extreme events in making bids and offers.

61 AMP activates when day-ahead LMPs exceed $150, which occurred on 19 days in 2003 through June; and on several days (NYISO did not report exact numbers) during July, August and September 2002. AMP's infrequent activation, broad tolerance ranges and lack of actual mitigation suggest that it had little effect on prices.

62 Specifically, about one-half of the unit-hours (one generator's bid during one hour) are mitigated. Preliminary NYISO sampling of day-ahead prices suggests that New York City mitigation suppresses prices by amounts ranging from $1/MWh to $8/MWh. Source: Staff discussions with NYISO.

63 NYISO Technical Bulletin #95 (Dec. 17, 2002).

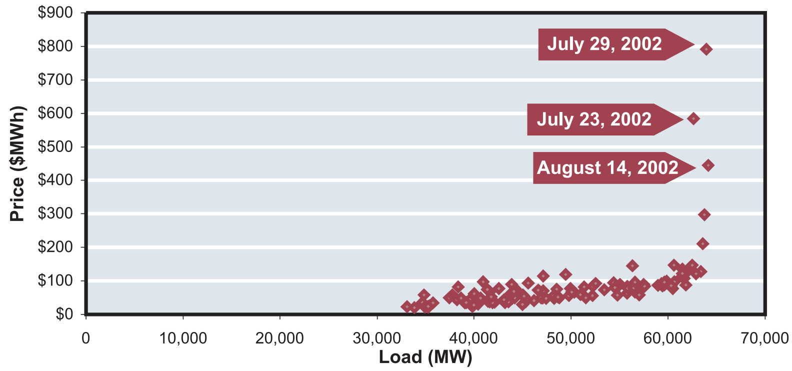
64 Potomac Economics Ltd., 2002 NYISO State of the Markets Report (June 2003).

65 By including congestion in locational prices, load pocket modeling also allows congestion costs to be hedged with transmission congestion contracts, which was not possible previously.

66 Order Conditionally Accepting Proposed Tariff Revisions (to implement scarcity pricing during reserve shortages); 103 FERC ¶ 61,339 (June 20, 2003).

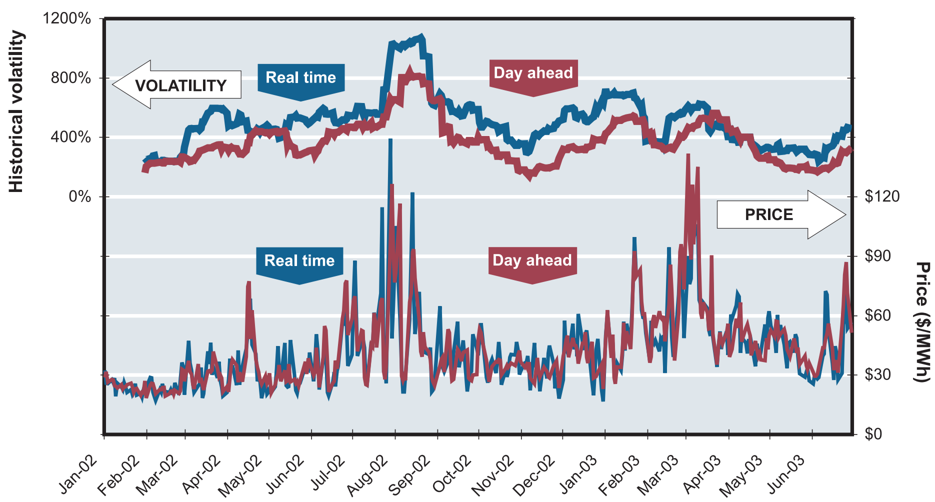
67 NYISO Tariff, Original Volume No. 2, Attachment H, Sec. 3.1.4 (c) (eff. July 8, 2003).

Figure 23: Summer PJM prices sensitive to peak load.



Source: PJM. Analysis and graphic by OMOI.

Figure 24: PJM real-time prices highly volatile.



Note: Data are from average on-peak prices. Historical volatility is calculated as the standard deviation of logarithmic returns, log (pricet /pricet-1), where standard deviation is based on the previous 21 on-peak days (weekdays excluding NERC holidays).

Source: PJM. Analysis and graphic by OMOI.

In 2002, real-time prices exceeded $400/MWh in three hours during the year and there were some persistent load pockets that caused localized LMP prices to rise under certain load conditions. In general, congestion, in the form of higher-than-system LMPs, was observed in high-load periods on various paths moving from western supply areas to eastern load centers. Forty percent of the congestion in 2002 occurred in July and August as did 34 percent in 2001.[68] The primary locations congested under certain load conditions during the assessment period include the Delmarva Peninsula (the eastern shore of Delaware, Maryland and Virginia), Erie (in northwest Pennsylvania), northern New Jersey, Bedington-Black Oak (on the Maryland-West Virginia border), Wylie Ridge (on the Pennsylvania-Ohio border), Doubs (on the Maryland-Virginia border) and Towanda-Meshoppen (in northeast Pennsylvania). Some of these areas have been the object of transformer upgrades and other substation enhancements, which have reduced the congestion in certain localities.

Transmission loading relief (TLR), which allows PJM to physically curtail load when necessary for the reliability and operation of the grid, is an additional, albeit cruder, congestion management tool. PJM still uses TLRs when necessary

[68] PJM State of the Markets Report, p. 105.

to relieve problematic congestion points. TLRs in PJM are normally called due to the effects of external loop flow on particular paths. This is a problem stemming from running an LMP system in PJM adjacent to control areas that do not use LMP and are not well coordinated with PJM's LMP. During the assessment period, TLRs in PJM were only used to curtail non-firm transmission transactions.

PJM applies its market power mitigation process in cases where a generator in a congested load pocket is needed for reliability purposes. This mitigation can be applied only to generating units whose construction began prior to July 9, 1996. The affected unit's supply offers are capped at their variable cost plus 10 percent.

ERCOT

The ERCOT market is based on bilateral transactions between buyers and sellers of energy. Balanced energy schedules are submitted to ERCOT by qualified scheduling entities. ERCOT only operates the electricity market needed to resolve the energy imbalances that result due to differences between real-time system requirements and the system loading anticipated in the balanced schedules.

As shown in Figure 17, balancing energy prices[69] in ERCOT ranged from $15 to $30/MWh through 2002. Prices began to rise in 2003 and reached a high of $990/MWh for seven hours in late February 2003,[70] roughly 80 times the average price for the previous week. The peak average daily price was $660 during this time period. ERCOT market prices are capped at $1,000/MWh. ERCOT's price spike coincided exactly with the late February 2003 natural gas price spike. However, Texas Public Utility Commission (PUCT) staff found that hockey-stick bidding[71] also contributed materially to the $990 price spikes in the Balancing Up Energy Service market during that time period.[72] From mid-March onward, prices averaged higher than the previous year, ranging from roughly $40 to $50/MWh.

Energy prices in the region generally responded as expected to variations in demand. Due to the high percentage of power generation capacity fueled by natural gas, the price of natural gas was a significant contributing factor to electric spot price levels and volatility in ERCOT. In addition, increased electric demand for space cooling due to hot weather and supply shortages from power generation plant outages drove prices higher. These market factors appeared to drive price variations during 2002 and 2003.

For congestion, ERCOT uses a zonal model that classifies the region into four zones (South-North, South-Houston, West-North and North-West; see Figure 76), and five significant constraint interfaces. In addition, there are local constraints that limit the flow of electricity within zones. ERCOT solves zonal and local congestion in two steps. In the first step, ERCOT dispatches zonal balancing energy to clear congestion, sets a price for each constrained interface and determines the market-clearing price for each congestion zone. In the second step, qualified generators submit bids for ancillary service shortfalls required for energy imbalances. If a Market Solution[73] can be calculated, ERCOT uses these resource-specific premiums to clear local constraints and to issue resource-specific instructions to relieve local congestion. It uses additional resource-specific procedures to rebalance zonal energy. When a Market Solution cannot be calculated—the case for more than 90 percent of the time that Market Solutions were needed in 2001 and 2002—ERCOT issues out-of-merit (OOM) dispatch instructions.

ERCOT-run markets in 2002 used a $1,000 limit on offer prices in the energy market. This limit was voluntarily followed by market participants for their offers for operating reserves as well.

CAISO

Although electricity consumption in 2002 was up 1.2 percent from the previous year, CAISO energy prices were lower in 2002 relative to 2001—particularly lower than in the first half of 2001, the end of high prices during the California energy crisis (see Figure 17). Overall, California experienced improvements to its supply resources because 6,800 MW of new generating capacity were added from Jan. 1, 2002 through June 30, 2003. Hydroelectric supplies also improved over the low water conditions in 2001, both in California and the Pacific Northwest. CAISO real-time prices continued to be volatile in general, but less volatile than in 2000 and 2001, as participants sold in the real-time market for time increments as brief as 10 minutes.

During the period of this report, in contrast to CAISO's first three years of operation, the vast majority of electricity bought and sold in the wholesale market in California was

[69] Balancing energy represents the change in zonal energy output or demand determined by ERCOT to be needed to ensure secure operation of the ERCOT transmission grid, and supplied by the ERCOT through deployment of bid resources to meet load variations not covered by regulation service.

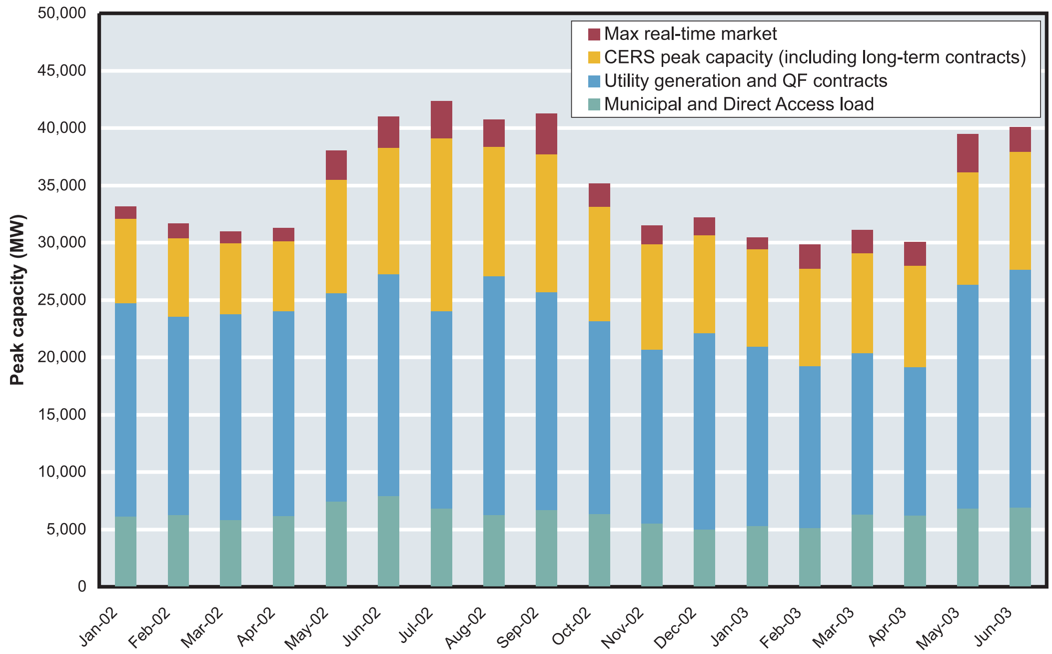
[70] Note that Figure 17 and Table 6 are based on the average price during peak hours (7 a.m.–10 p.m.) on each day. The $990/MWh price does not appear because it is averaged in with the prices from all other peak hours during that day.

[71] Hockey-stick bidding is when a market participant submits a small portion of its bid at an extremely high price. If ERCOT procures all available bids, including the tip of the "hockey stick," then the most expensive megawatt hour sets the market-clearing price.

[72] PUCT, "Analysis of Balancing Energy Price Spikes During the Extreme Weather Event of February 24-26," filed in Project No. 23100, Market Oversight Activities, on March 3, 2003.

[73] A Market Solution exists when at least three unaffiliated resources, with capacity available, submit bids to ERCOT that can solve a circumstance of local congestion and no one bidder is essential to solving the congestion.

Figure 25: California's real-time energy market is a small part of total market.



Note: Estimated values of monthly peak generation from CAISO's real-time energy market, CERS-procured supplies, utility generation, QFs, and municipal and Direct Access sources. Estimates are non-coincident. "CERS" is the California Energy Resources Scheduling division of the California Department of Water Resources.

Sources: CAISO Oasis, CAISO DMA Annual 2002 Report on Market Issues and Performance, and CAISO DMA data responses. Analysis and graphic by OMOI.

provided through long-term contracts negotiated by the state during the energy crisis in 2001.[74] The CAISO manages a real-time imbalance energy market that reconciles deviations between constantly changing system load and generation output.[75] Figure 25 shows the relationship between long-term contracts and other energy sources. CAISO's INC and DEC energy markets[76] manage deviations for real-time only. During the assessment period, there was no organized day-ahead energy market, resulting in less information about actual costs of electric energy in CAISO than provided by other RTOs and ISOs about their areas.

INC and DEC energy prices did not always result in increasing prices with increasing system load. In some high load hours, prices were less than or equal to prices seen at lower load levels. Because CAISO's real-time INC and DEC energy markets are largely markets of residuals (CAISO's energy markets fill the relatively small and volatile residual needs of the three major IOUs after their own generation, long-term contracts and other bilateral purchases), real-time energy prices were closely related to the imbalance load of the three major IOUs. Other factors such as natural gas prices also explained variations in real-time prices. During 2002, through October, a bid cap provided mitigation that limited seller bids. The market-clearing price was thus

[74] CAISO and the California Power Exchange (PX) commenced operation in April 1998. During the first three years of operation, California's investor-owned utilities were required by state regulations to purchase and sell all of their electricity through the California PX with little or no ability to purchase through forward contracts. In January 2001, the PX ceased operations. As a result of the financial insolvency of PG&E and SCE during the energy crisis, the State of California commenced procuring all energy and ancillary services for the net short needs of the investor-owned utilities in 2001. By the start of 2002, overall utility energy demand was met by a mix of electricity from utility-owned generation, existing contracts with QFs, the state-negotiated bilateral purchases and long-term contracts and purchases from CAISO for balancing energy and ancillary services. In January 2003, the investor-owned utilities resumed making purchases from CAISO and bilateral markets to fill the difference between their retail customer load and the above described resources. Incremental (INC) procurement needs were relatively small, arising primarily from customer load growth. Notably, INC prices during the period of this report were based on power purchases for a small amount of customer load, less than 5 percent of total load on average, as the CAISO market was intended to support. This is in contrast to the large energy volumes in the CAISO market during the electricity crisis.

[75] CAISO also operates markets for ancillary services in both the day-ahead and hour-ahead. These services include Spinning Reserves, Non-Spinning Reserves, Replacement Reserves and Automatic Generation Control/Regulation capabilities.

[76] A separate market clearing price is set for each of six ten-minute intervals in an hour for increasing generation output, an INC price, and for decreasing generation output, a decremental (DEC) price. The INC and DEC prices are determined for three defined zones: NP-15 (northern California), SP-15 (southern California) and ZP-26 (Central Coast). A single market clearing price is set unless there is real-time congestion between the zones.

limited to the cap of $108/MWh for the January–April period and the cap of $91.87 for the May–October period.[77]

Congestion cost information was not as clearly revealed in the CAISO market framework and prices as in other organized markets. During the assessment period, costs were split between interzonal and intrazonal congestion. Interzonal congestion costs were reflected in the energy prices through a usage charge applied to transactions across the zonal boundaries and interties. The total interzonal congestion costs were $42 million in 2002 and $11 million in the first half of 2003. Intrazonal congestion management was performed in the real-time market and costs were allocated to all scheduling coordinators as an uplift charge in proportion to their scheduled load within a zone (plus net exports out of a zone). Total intrazonal variable congestion costs in 2002 were $10 million.

The lack of explicit pricing of intrazonal congestion led to perverse signals for new generating units. For example, three Mexico generating units that came on line July 2003 were major contributors to intrazonal congestion costs, totaling approximately $5 million from July through the beginning of October 2003 (annual projected cost is greater than $30 million). These generating units operate under bilateral contracts. The generating unit suppliers did not directly face the costs of the congestion they created under the existing CAISO market design. Suppliers may submit schedules within a zone without regard to available transmission capacity (e.g., without taking into account transmission line or transformer limits within the zone). The costs of relieving the congestion from these "infeasible" schedules manifest as payments to dispatch generating units out of merit order sequence (certain RMR unit dispatch costs are included in intrazonal congestion costs). These costs are not paid by those who create the congestion, but rather by the scheduling coordinators of load within the zone. Such intrazonal charges to load are independent of the entities that create the congestion and thus provide little incentive for suppliers market participants to submit schedules that minimize congestion costs.[78]

While the new generation in Mexico was welcome for providing new power supplies, transmission upgrades did not keep pace with the new generation. As described above, the existing market design flaw of accepting infeasible schedules in the day-ahead period resulted in the ISO needing to decrementally dispatch generating units in real-time to maintain local grid reliability. CAISO has referred to this case as the "DEC game." The market participants, while creating the intrazonal congestion in their day-ahead schedules, are not charged for the congestion and then subsequently get paid to relieve the congestion by decrementing their flows in real time.[79] CAISO's proposed market redesign charges congestion costs to those who cause the congestion, which should resolve the problem.[80]

Market power mitigation measures in CAISO consist of AMP, a must-offer requirement, a $250/MWh bid cap and RMR contracts (see Table 9). While 6,800 MW of new generation were added to California, little new generation has been built inside the high-load urban areas of San Francisco, Los Angeles and San Diego. Because of transmission constraints leading into these areas, they continued to have highly concentrated generation supply relative to demand and remain load pockets. The existing supply within the load pockets would have had locational market power in many hours and the CAISO market used RMR contracts to mitigate the suppliers' market power. Little progress was made toward investment in load pockets that would minimize the need for RMR unit designations. The last sizable amount of infrastructure investment made in the load pockets, which reduced the quantity of RMR unit designations, was completed in 2000.[81] Incentives for new investment in load pockets may be weak. While the RMR contracts mitigate market power concerns, they, together with CAISO's zonal pricing system (rather than a location-specific system), further masked market signals for investment in load pockets.

Investment signals in load pockets are further removed from a locational market-based approach by switching terms on the RMR contracts as is an existing option for RMR owners. Weak financial conditions of some market suppliers during the study period made it attractive to switch RMR contract terms to substitute the complete collection of cost-based revenues for what they previously opted for: receiving market revenues at certain times while receiving a portion of their costs through a cost-based formula.[82] The alternate contract terms, titled "Condition 2," essentially provide that the RMR unit owner

77 95 FERC ¶ 61,115 (Apr. 26, 2001 order) and 95 FERC ¶ 61,418 (order on rehearing, June 19, 2001).

78 Order on Proposed Tariff Amendment No. 50, 103 FERC ¶ 61, 265.

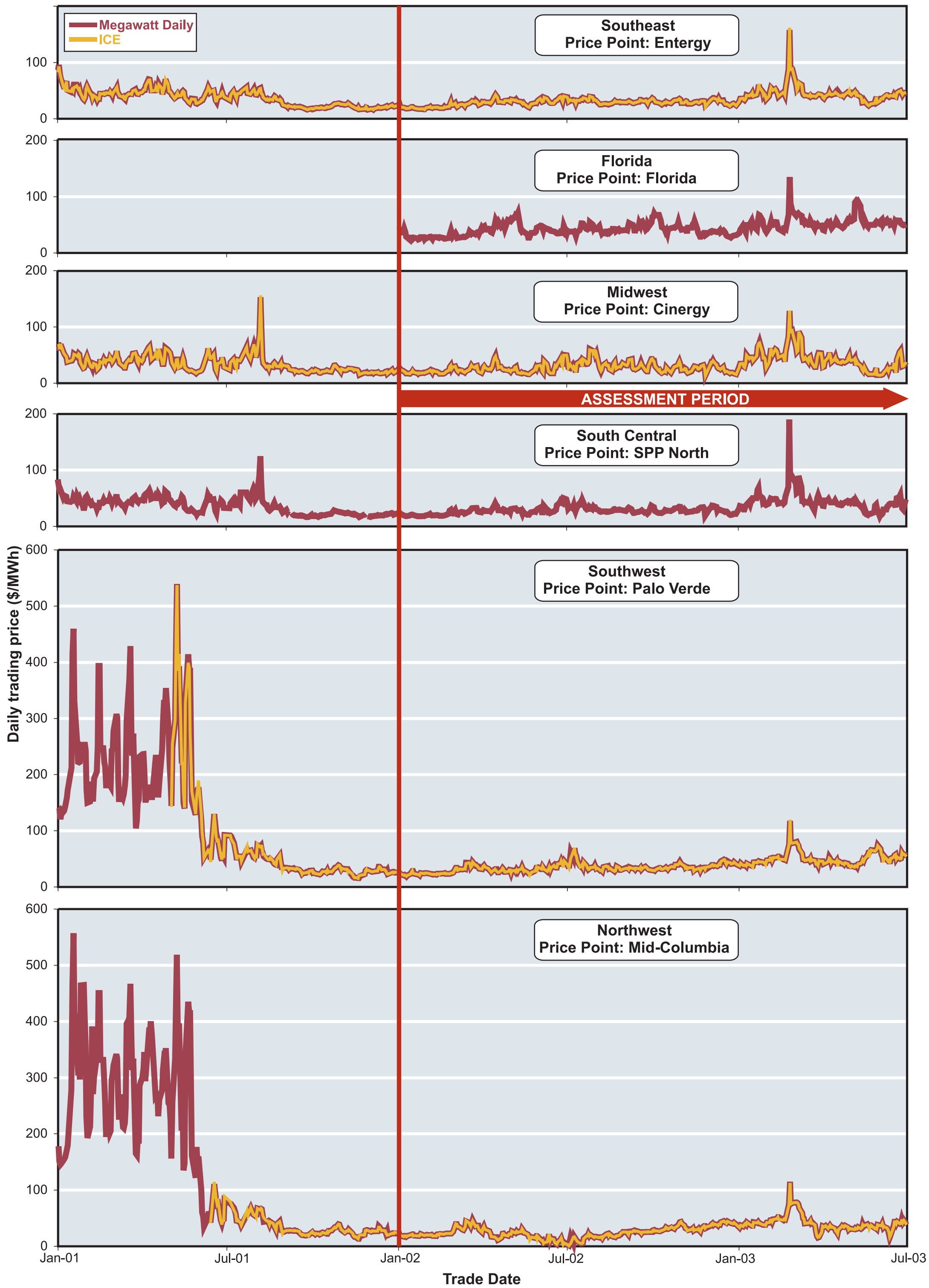
79 For example, see the California ISO White Paper, "Options for Managing Intra-Zonal Congestion on the Miguel Substation" (www.caiso.com/docs/2003/10/17/2003101716353222638.pdf).

80 The overhaul of California's electricity markets was initiated by the CAISO in December 2001, as a result of the Commission's Jan. 7, 2000 and Dec. 19, 2001 orders which required the CAISO to submit a plan for redesigning the CAISO congestion management system, and for creating a day-ahead energy market (California Independent System Operator Corp., 90 FERC P 61,006 at 61,013-61,014 (2000), San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange. et al., 97 FERC P 61,275 (2001)).

81 Proposals for new generation and transmission have been made in California possibly affecting the future quantity of capacity designated as RMR depending on whether the projects are approved and financed. Source: CAISO-DMA.

82 RMR generating unit owners were able to switch RMR generating units providing service under one form of the RMR contract, termed "Condition 1," a form that allows the generator to bid into the market and retain market revenues (with certain restrictions) along with a negotiated fraction of their annual costs, to another contract form, termed "Condition 2," a form that precludes the generator from retaining market revenues and only a cost-based, formula-determined amount of revenues. The switch between condition terms is allowed only once per year.

Figure 26: Regions without organized markets have prices generally lower than in 2001, though spikes occur.



Notes: *Megawatt Daily* and ICE data are volume-weighted day-ahead peak prices. SPP North and Florida contracts did not have active markets for day-ahead power on ICE.

Source: Platts *Megawatt Daily* and ICE. Analysis and graphic by OMOI.

will receive enough revenue to maintain the unit in operation without the risk of market revenue uncertainty. Though revenues RMR unit owners receive are limited to levels that were once seen as unattractive (i.e., during the first few years of ISO operation), the increased capacity under the cost-based Condition 2 form of the RMR contract tended to lower the volumes offered in the real-time energy and ancillary services markets. This reduction in offers was offset for the overall market by new generation that has come on line. OMOI will continue to monitor this issue.

Short-term Markets in Regions without Organized Markets

Reported electricity prices in regions without organized markets operated by RTOs and ISOs—the Southeast, Florida, the Midwest, South Central,[83] the Southwest and the Northwest84—appear to have generally behaved in accordance with observed forces of supply and demand over the assessment period, though it is more difficult to be certain of this observation due to the limited amount of available data. The only source of energy pricing information in these regions was indices for electricity to be delivered during the 16 peak hours of the next day. Prices for blocks of power for the remaining off-peak hours were sometimes also available. These price indices did not provide market participants with prices for individual hours during the coming day. In addition, these prices were derived from a subset of transactions, those conducted on ICE and reported to trade publications. Organized markets have bilateral price and volume transparency, but they also have information on price and volume for hourly power derived from the trading of all market participants in ISOs or RTOs.

Prices, market activity and congestion during the assessment periods are discussed broadly across regions below, followed by more detailed region-specific discussion.

As shown in Figure 26 and Table 11,[85] 2002 day-ahead bilateral prices in regions without organized markets averaged lower than 2001 levels, trending upward in summer 2002 and during the February/March 2003 natural gas price spike. The average first-half 2003 prices were about 20 percent higher than full-year 2001 levels, with the exception of the western trading hubs of Mid-Columbia and Palo Verde where prices remained significantly below 2001 levels through the end of the second half of 2003.

Differences between ICE and *Megawatt Daily* prices evident in Table 11 are in part due to data availability. For example, ICE's mean Palo Verde price is significantly lower than the mean Megawatt Daily price because ICE data were only intermittently available in 2001.

Table 11: Prices in regions without organized electricity markets.

Price ($/MWh)		2001			2002			First half of 2003			First half of 2003 (adjusted***)		
		Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean
Southeast (Entergy)	ICE	16.00	93.00	37.05	16.51	42.48	28.52	22.56	161.63	44.47	22.56	62.27	41.56
	MWD	16.40	95.95	37.40	16.64	42.37	28.54	23.25	158.00	44.43	23.25	63.50	41.48
Florida	ICE**	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	MWD*	25.00	97.50	46.19	23.00	71.00	40.29	35.00	135.00	54.37	35.00	92.00	52.53
Midwest (Cinergy)	ICE	15.47	156.33	34.98	13.06	60.16	27.01	14.26	128.85	41.86	14.26	81.05	38.70
	MWD	15.19	152.97	34.91	14.02	60.94	27.08	14.46	128.51	41.79	14.46	92.02	38.61
South Central (SPP North)	ICE**	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	MWD	16.33	125.00	36.98	17.77	50.00	27.67	17.75	190.00	44.14	17.75	90.00	40.43
Southwest (Palo Verde)	ICE*	15.66	537.50	81.38	19.00	69.89	33.02	35.65	119.56	49.92	35.65	73.51	47.41
	MWD	15.75	539.03	123.33	18.81	69.39	33.08	35.63	117.94	50.06	35.63	74.30	47.74
Northwest (Mid-Columbia)	ICE*	13.65	450.00	50.90	1.01	45.70	24.04	15.97	112.71	40.37	15.97	59.06	37.18
	MWD	13.63	557.14	145.10	1.43	46.21	24.28	15.56	115.18	37.39	15.56	68.43	37.39

Notes: *Data intermittent in 2001. **Did not have an active market for day-ahead power on ICE.
***Excludes 2/24–3/9 (period of 2002 natural gas price spike).

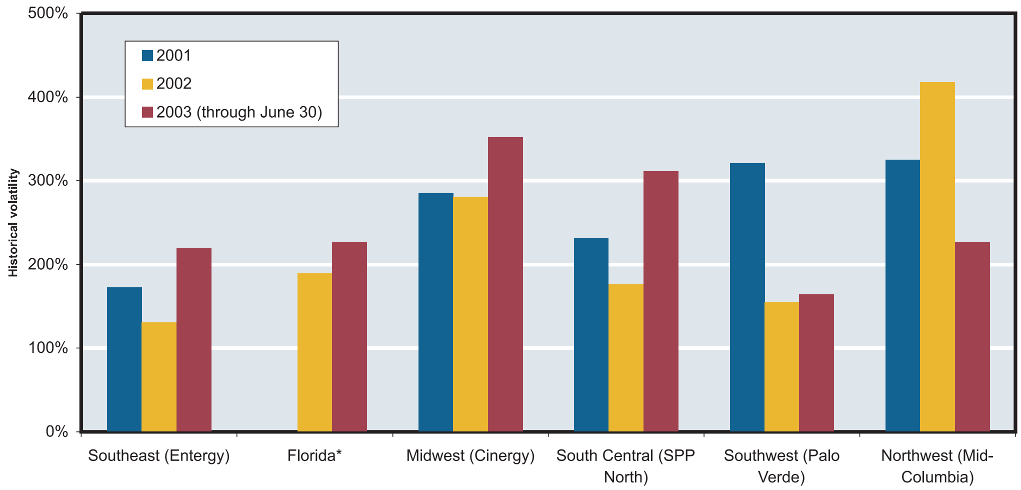
Source: Platts *Megawatt Daily* and ICE.

83 During the assessment period, Entergy was in preliminary stages to join SeTrans, a proposed RTO in the Southeast. For this reason, it was placed in the Southeast, not South Central. Depending on future activities, we may realign the regions in subsequent reports.

84 For a map of these regions, see Figure 8.

85 To compare price, volatility and market activity across regions, OMOI selected one representative pricing point for each region, based on factors such as underlying liquidity and location.

Figure 27: Price volatility increases in most regions without organized markets.



Note: Data are day-ahead on-peak prices. Annualized historical volatility is calculated as the standard deviation of logarithmic returns, log ($price_t$ /$price_{t-1}$), where standard deviation is based on all on-peak days (weekdays excluding NERC holidays) during the period. *There is no 2001 volatility calculation because Florida prices were intermittently reported prior to January 2002.

Source: Platts *Megawatt Daily*. Analysis and graphic by OMOI.

Table 12: Reported trading volumes in regions without organized electricity markets.

Average daily volumes (GWh)	Entergy		Florida		Cinergy		SPP North		Palo Verde		Mid-Columbia	
	MWD	ICE	MWD	ICE	MWD	ICE	MWD	ICE	MWD	ICE	MWD	ICE
2001 (full year)	69	43	1	N/A	180	128	6	N/A	17	10	16	6
2002 (full year)	54	73	2	N/A	127	193	5	N/A	22	32	26	42
2003 (first half)	13	30	0	N/A	61	130	0	N/A	11	22	19	33

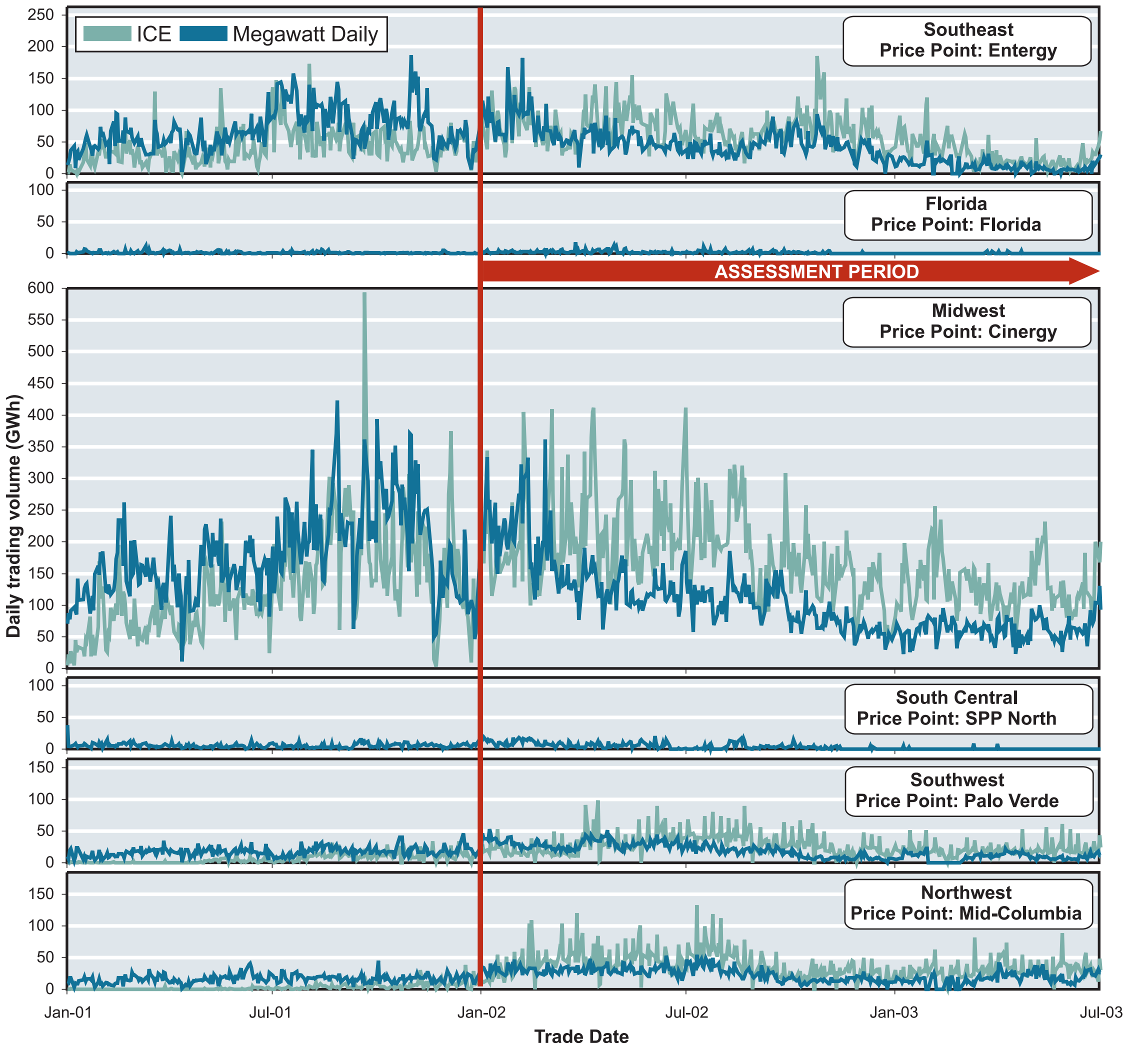
Note: ICE did not report trade volumes for Florida or SPP North. *Megawatt Daily* volumes reflect on-peak transactions surveyed by the trade publication. *Megawatt Daily* data have been modified to make them comparable to ICE data. *Megawatt Daily* volumes have been multiplied by 16 to convert from a 16 peak-hour MW contract into a MWh. Final volumes are converted to GWh. In addition, since *Megawatt Daily* volumes include both buy and sell sides of transactions and ICE volumes include only the sell side of transactions, ICE volumes were doubled.

Source: Platts *Megawatt Daily* and ICE.

As shown in Figure 27, price volatility in each region did not exhibit a unified trend since 2001. Volatility in the Midwest (Cinergy), Southeast (Entergy) and South Central (SPP North) increased since 2001, whereas volatility decreased in the Northwest (Mid-Columbia) and Southwest (Palo Verde) during the same time period. The decline in volatility in the western regions was due, in part, to more stable overall price levels in comparison to the energy crisis. Lower levels in the Northwest in particular were due to improved hydroelectric conditions.

Both the number of next-day physical transactions reported to the index publishers and transacted on ICE declined during the assessment period as shown in Figure 28 and Table 12. This effect was also apparent in regions with organized markets. Although market activity as measured by transactions reported to the trade press began to increase slightly towards the end of the assessment period in some regions, it did not approach the levels of prior periods. The decline was likely the result of the reduced number of creditworthy trading participants and may also be the result of a decline in wash trading. Later in the assessment period, transactions on ICE rebounded more strongly, particularly in regions without organized markets. The very low number of transactions reported in Florida may be due to the high concentration of the market. Market participants may find little value in reporting to the trade press because the

Figure 28: Reported trading volumes decline in regions without organized markets.



Note: ICE did not report trade volumes for day-ahead power for Florida and SPP North. *Megawatt Daily* volumes reflect on-peak transactions surveyed by the trade publication. *Megawatt Daily* data have been modified to make them comparable to ICE data. *Megawatt Daily* volumes have been multiplied by 16 to convert from a 16 peak-hour MW contract into a MWh. Final volumes are converted to GWh. In addition, since *Megawatt Daily* volumes include both buy and sell sides of transactions and ICE volumes include only the sell side of transactions, ICE volumes were doubled.

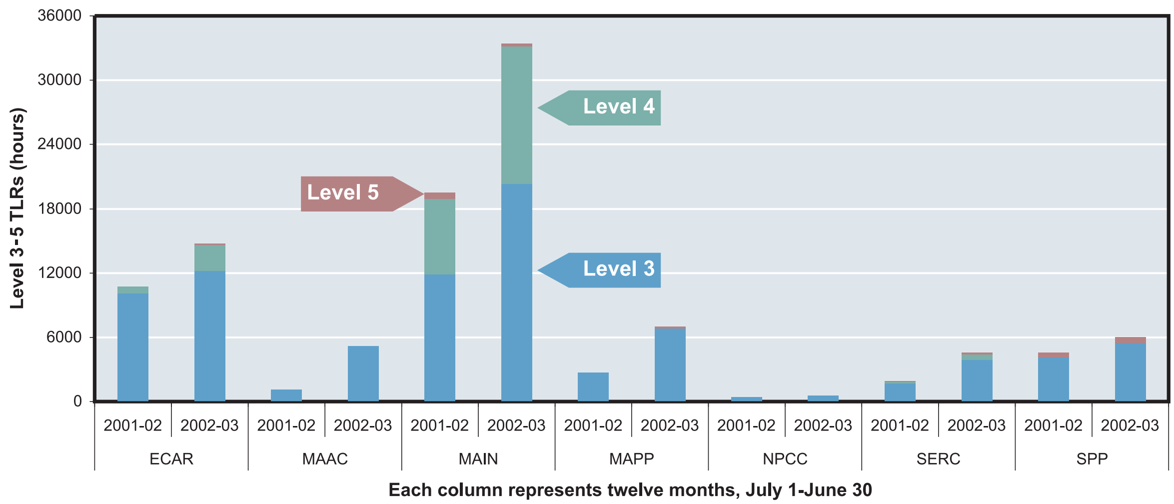
Source: Platts *Megawatt Daily* and ICE. Analysis and graphic by OMOI.

prevailing price is revealed through transactions within a small pool of counterparties.

Regions without organized markets lack any market-based approach to managing congestion. In the Eastern Interconnection, system operators use TLRs. TLRs are called when electricity flows exceed permitted levels to preserve the reliability of the electric transmission system. TLRs interrupt specific transmission flows or transactions and may curtail service to specific customers or future transmission schedules. The TLR procedure addresses reliability concerns and relies on administrative procedures rather than market mechanisms to control transmission flows. The procedure is not efficient, either in terms of minimizing flow needed to resolve constraints or of minimizing the economic cost of redispatch. It is also not administered uniformly, making congestion assessment extremely difficult outside RTOs and ISOs.[86]

[86] Regions with organized markets and within the Eastern Interconnection may call TLRs, but do so rarely because their LMP system prevents most congestion from rising to a level that necessitates calling a TLR.

Figure 29: TLR activity increases in most regions.



Note: 2001–02 includes TLRs during the 18-months prior to the 2002–03 assessment period.

Source: FERC analysis of data and past events from NERC's Central Repository for Security Events. Graphic and further analysis by OMOI.

For the period July to December 2002, the MISO independent market monitor estimated that optimal redispatch based solely on flow (as under an LMP system) could be used far more efficiently than the TLR system that was used. Flow-driven redispatch would relieve congestion with 30 percent fewer MWs redispatched; economic redispatch would relieve congestion with 38 percent fewer MWs redispatched.[87]

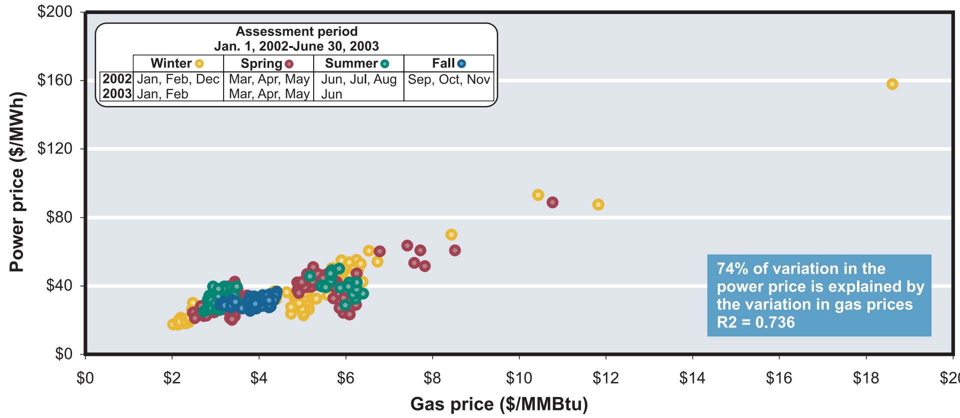
Figure 29 compares the total number of hours of high-level (Level 3, 4 and 5) TLRs called in the years ending June 31, 2002 and June 31, 2003. TLRs, which are used to respond to congestion in real time, increased in all regions. However, because different regions in the Eastern Interconnection use different procedures for scheduling power and managing congestion prior to real time, comparing levels of TLRs across regions does not provide an accurate reflection of overall congestion in a region.

Regions without organized markets in the Western Interconnection do not use TLRs to manage congestion, partly due to regional system conditions. The Western Interconnection uses the procedures of the Western Electricity Coordinating Council (WECC) to schedule transactions, determine transmission line and path ratings, and curtail transactions when needed to maintain reliability. The procedures differ from the NERC procedures in the Eastern Interconnection, reflecting geographic and system condition differences in the two interconnections. The Western Interconnection service area is less densely populated than the Eastern Interconnection, carries power over longer distances, and is more subject to voltage and stability constraints than the Eastern Interconnection. In addition, the transmission system carries significant baseload power on many of the paths flowing from eastern parts of the service area, where baseload coal generation is located, to western population centers. The paths that carry these flows are heavily loaded, but less subject to variation in flow and flow overloadings than paths in the Eastern Interconnection. As a result of these differences, the Western Interconnection did not develop a TLR congestion management system, but instead developed separate procedures for rating major transmission paths, determining transmission capacity on these paths, developing and adjusting interchange schedules between control areas and curtailing schedules when line limits are exceeded. While these procedures resemble TLRs in the Eastern Interconnection by relying on an uneconomic curtailment of transactions in real-time, they differ in the specifics and are not uniform across the Western Interconnection.

Regions without organized markets in both the Eastern and Western Interconnections have costs associated with the inability of lower cost generation to get to market that are not explicitly priced but are borne by customers in the region. In the Eastern Interconnection, TLRs curtail transactions, often forcing higher cost generation to be used than would be the case under a market-based system. During the assessment period, these curtailments and costs rose relative to the prior period. In the Western Interconnection, operation of phase angle regulators (sometimes called phase

[87] MISO, "2002 State of the Markets Report," prepared by Potomac Economics Ltd., independent market monitor for MISO, May 2003.

Figure 30: Entergy electricity prices correlate with natural gas prices.



Notes: Power price point is Entergy. Gas price point is Henry Hub.

Source: Platts Gas Daily and Platts *Megawatt Daily*. Analysis and graphic by OMOI.

shifting transformers) and generator ramp downs may have sometimes prevented lower cost generation from getting to market. Phase angle regulators control transmission flows to address local overload problems and unscheduled flows across the system and ramp downs are called by security coordinators to manage congestion.

To the extent information is available, we consider the specific electricity price performance over the assessment period in each of these bilateral markets separately.

Southeast

Prices in the Southeast (excluding Florida) remained low during the assessment period, as represented by the Entergy pricing point, which is the most liquid point in the region. Prices at Entergy tended to range from $20 to $40/MWh, with somewhat higher prices occurring in the summer and during the natural gas price spike in February/March 2003 (see Figure 26). These remained quite stable, with a comparably low level of volatility and a modest correlation to load. In spite of the high proportion of coal and nuclear powered generation (84 percent of the production during the period), gas was the marginal fuel 58 percent of the time (see Figure 4) and led to a strong correlation between natural gas prices and power prices (see Figure 30).

Moderate weather conditions and high reserve margins contributed to the low price levels experienced over the period. Available resources were added faster than load grew. Reserve margins reported by SERC ended the period at 17 percent, however, merchant generation in the region was not included in this calculation unless the load-serving entity has a contractual arrangement with the merchant plant, and the capacity was reported through the EIA-411 reporting process.[88] If all the assets in the region were included, the total generation would exceed the load by approximately 65,000 MW, or 41 percent. This results in a total connected generation capacity that exceeds the projected load growth for the region through 2012.[89]

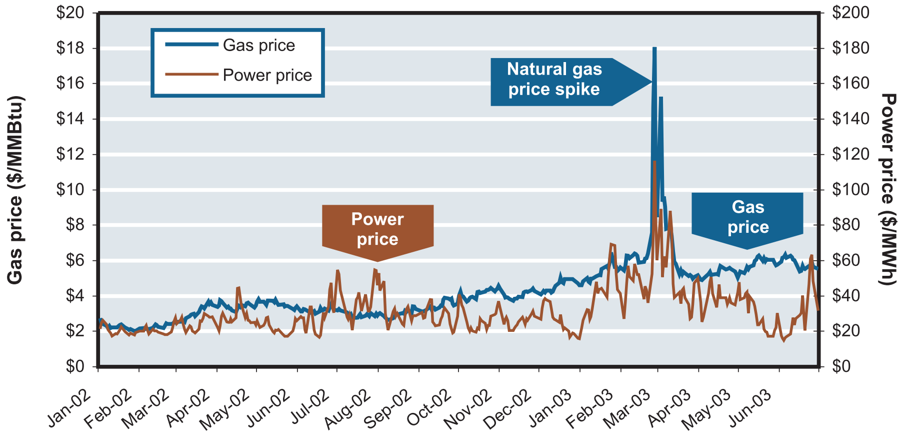
Florida

Power prices in the Florida bilateral market generally remained moderate and stayed within the range of $25 to $60/MWh on more than 90 percent of the reported trading days (see Figure 26). Prices exceeded $100/MWh on one occasion, during the February/March 2003 gas price spike. There was moderate price volatility and prices responded to load and fuel input prices as expected and showed a significant correlation to gas prices. This can be attributed to the significant amount of gas-fired generation capacity that operates at the margin in this region. An unseasonably warm winter and inexpensive natural gas kept average prices below $30 during January and February 2002. A May 2002 heat wave created unprecedented loads at a time when some generation was unavailable because of seasonal maintenance, causing brief prices spikes. Hot weather in July and August 2002 maintained prices levels in the $55 range. Late in winter 2002–03, high natural gas used for electric generation prices caused an extended period of higher electricity prices.

[88] SERC, Reliability Review Subcommittee's 2003 Report to the SERC Engineering Committee, June 2003.

[89] SERC, Reliability Review Subcommittee, Presentation of Generation Development Survey Results: SERC EC-OC-MIC Spring 2003 Meeting, March 13, 2003.

Figure 31: Midwestern power price spike may make gas-fired units competitive.



Note: Power price point is ComEd; gas price point is Chicago Citygate.

Source: Platts *Megawatt Daily* and Platts Gas Daily. Analysis and graphic by OMOI.

Midwest

Bilateral prices in the Midwest were higher in the 12 months ending June 30, 2003, than in the previous 12 months, but they tended to remain in the $20–$40/MWh range throughout most of the year (see Figure 26). In addition, volatility remained constant in the Midwest over the past five years with the exceptions of some short stretches in June 1998[90] and summer 1999 when prices spiked more than 350 percent.

The region is heavily reliant on coal-fired generation, accounting for approximately 77 percent of all Midwest generation in 2002. Natural gas was on the margin less than in other regions, between 10 and 23 percent, and units operating on natural gas accounted for 3 percent of generation. However, units operating on natural gas represent the majority of new generation being built. In general, the region has a relatively large capacity reserves margin that exceeds 20 percent in most areas. However, there are congested areas within the Midwest, most notably, the Wisconsin-Upper Michigan subregion (WUMS). Congestion in the WUMS area is in part due to transmission configuration changes and a weak transmission interface.

Because of the relatively large capacity reserves margin and the minimum amount of natural gas-fired generation, natural gas units are infrequently used to meet native load. However, as shown in Figure 31, during summer 2002 and in February/March 2003, power prices approached and briefly exceeded $100/MWh, indicating that the operation of a natural gas generator may have been economical. This high price might suggest that natural gas units were on the margin, or it could reflect the opportunity cost of a less expensive unit selling its power outside the Midwest region. Since MISO is in implementation phase, market information is sparse. The lack of information makes it difficult to discern whether the high prices experienced during this assessment period were determined by the internal dispatch of gas-fired units or a premium paid by external demand in relatively more expensive areas.

South Central

Daily spot prices in the South Central region ranged from $30 to $50/MWh between January 2002 and June 2003 and reached $190/MWh in late February and early March 2003 when natural gas prices spiked across the country (see Figure 26). Volatility generally is greater when reserve margin limits are approached and in this region the reserve margin increased from 2002 into 2003. Daily spot prices in the region were stable during this period with the exception of two periods of heightened volatility. The first was in July and August 2002 which reflected hot summer temperatures and corresponding high demand. The second was in February and March 2003 when gas prices spiked across the country.

[90] The 1998 spike was due to generation outages (both planned and unplanned), unseasonably hot temperatures (that were not forecasted), transmission constraints, opaque and delayed market information systems, and lowered market confidence due to sales contract defaults. (See FERC, "Staff Report to the Federal Energy Regulatory Commission on the Causes of Pricing Abnormalities in the Midwest during June 1998.")

Prices responded to load and fuel input prices as expected. Power prices showed a significant correlation to gas that remained consistent, regardless of season, and was largely attributable to the amount of gas-fired generation capacity that operated at the margin. Combined with an unseasonably warm winter and inexpensive natural gas, this kept average prices between January and late-February 2002 close to $30/MWh. As in the other regions, high fuel prices as well as transmission congestion (evidenced by TLR activity) caused an extended period of high electricity prices late in winter 2002–03.

Southwest

Market participants are limited to surveyed price information for two locations in the region, Palo Verde and Four Corners (for Palo Verde price information, see Figure 26). The Southwest does not have intraday price information. Volatility of daily spot prices in the region decreased since the energy crisis in the West when prices averaged well over $100/MWh and peaked at $539. Excluding prices from the February/March 2003 price spike, daily spot prices at Palo Verde averaged $38 during 2002 and the first half of 2003. The peak price of $118 during the February/March 2003 price spike was less than average Palo Verde electric prices during the energy crisis in the West.

During 2002 and 2003, Southwest spot prices reflected a less strained market than in 2001 due to improved reserve margins. The additional 8,420 MW of new generation that came on line in the region easily outstripped load growth due to weak to modest economic growth. However, prices for Southwest-traded electricity followed the February/March 2003 natural gas price spike because most of the new capacity added in the region was gas fired.[91]

The new units were generally not located in urban areas experiencing the most rapid load growth, such as Las Vegas and several cities in Arizona. Therefore, the urban load pockets continued to have problems getting access to the lowest cost available power in the region. The bilateral pricing points for the region, Palo Verde and Four Corners, did not signal this location-specific need. In fact, more generation was built at Palo Verde than the transmission system could accommodate, reflecting a disconnect between the interconnection process and a regional transmission plan.[92]

Northwest

Daily spot prices in the Northwest were less volatile in 2002 and first half of 2003 compared with the preceding two year's energy crisis in the West. During the review period, Mid-Columbia daily spot prices averaged $24/MWh and $40/MWh, in 2002 and first half 2003, respectively (see Figure 26; see Appendix 6 for approximate price point locations). Similar to the Southwest, prices during the February/March 2003 price spike ($113/MWh) were less than average prices seen during the years 2000 and 2001. In addition to daily electricity prices surveyed and published by the trade press for the California-Oregon Border (COB) and Mid-Columbia pricing hubs, Northwest market participants had limited access to intra-day electricity prices through ICE, which posted hourly prices as traded on its platform.

The system stresses of the energy crisis had dissipated by 2002. Load increases were served with the 4,019 MW of new capacity brought on line during 2002 and 2003. In addition, hydroelectric generation in the Northwest produced 32 percent more energy than in the extremely dry 2001. Northwest market prices during 2002 and 2003 were consistent with the expected effect of improved hydroelectric conditions. Market prices tended to decline, reflecting lower hydroelectric opportunity costs. During seasonal periods of low water flows and reduced hydroelectric output, market prices reflected to a greater degree the higher natural gas-fired generation prices seen in the other regions of the West. Sixty percent of the electricity consumed in the region during 2002 was generated at hydropower plants, 31 percent was generated at coal-fired power plants and 4 percent was generated at natural gas-fired plants. Thus, with low installed amounts of natural gas-fired generation, and given a limited potential frequency of the natural gas-fired plants in the Northwest to set market prices (i.e., times of low, but non-zero hydro energy export availability), the Northwest market prices appeared to reflect the opportunity costs the resources in the Pacific Northwest had for trading elsewhere in the West.

Long-term Markets

The ability to enter into forward contracts is an important aspect of well-functioning markets. Forward contracting provides a risk management tool that allows market participants to reduce exposure to changing market prices. Forward contracting, whether standardized in futures markets or customized through bilateral contracts that are physical or financial, is a source of price discovery and offers both signals and contractual support for long-term investment. Prices for long-term forward markets are based on the interplay of short-term or current prices, and expectations of future demand, supply and market conditions for a given commodity. Forward prices can be observed in price curves on exchanges such as Nymex and ICE, as well as in bilateral markets.

91 Platts POWERdat, Modeled Production-Cost dataset, EIA Form 906, EIA 759 and FERC 423. Baseload generation is largely coal in the Southwest as 62 percent of the electricity consumed in the region was generated at coal-fired plants.

92 Arizona Corporation Commission, Second Biennial Transmission Assessment 2002-2011, Docket No. E-00000-D-02-0065, December 2002.

Table 13: Short-term and long-term contracting by region.

		Contracting by region:			
		Short term		Long term	
		000 GWh	Share	000 GWh	Share
Regions with organized markets	**ISO-NE**				
	ISO-NE	219	69%	69	22%
	NYISO				
	NYISO	79	72%	19	18%
	PJM				
	MAAC	475	61%	201	26%
	ERCOT				
	ERCOT	62	77%	18	23%
	CAISO				
	CA-MX	258	77%	55	16%
Regions without organized markets	**Southeast**				
	SERC	100	56%	67	38%
	Florida				
	FRCC	2	30%	5	69%
	Midwest				
	ECAR	233	70%	87	26%
	MAIN	42	20%	162	79%
	MAPP	39	86%	5	10%
	South Central				
	SPP	8	30%	18	69%
	Southwest				
	RMPA	3	41%	3	45%
	AZ-NM-SNV	87	79%	17	16%
	Northwest				
	NWPP	102	73%	32	23%

Note: In the EQR, companies report wholesale power sales within FERC's jurisdiction. Generation to serve one's own load, sales by federal authorities such as TVA and BPA, sales occurring fully within ERCOT and sales by qualifying facilities (QFs) under QF contracts are not included. Filings with clear errors affecting total sales were eliminated from the dataset pending correction from the submitting company. Regional allocation of sales was estimated using Point of Delivery Control Area and Specific Location information provided in the filings. All sales to ISOs were assumed to be short term and to occur within the ISO's control area. Percentages may not sum to 100 percent because some contracts are not defined in the EQR database or are not defined as either "long term" or "short term."

Source: Derived from FERC EQR, Fourth Quarter 2002 through Second Quarter 2003.

As seen in Table 13, although there is wide variation across regions, it appears that customers in regions with organized markets on average used a somewhat lower percentage of long-term contracts in their supply portfolios than in regions without organized markets, 22 percent and 36 percent respectively. Reports from three regions without organized markets indicate a relatively significant reliance on long-term contracts. Reported sales in FRCC were 69 percent under long-term contracts, 69 percent in SPP and 79 percent in MAIN.[93] Across all regions, approximately 28 percent of reported U.S. sales are delivered under long-term contracts of one year or longer. Despite significant reliance on long-term bilateral electricity contracts, there is limited forward price transparency to facilitate this contracting.[94] Futures markets for electricity were not available during the assessment period, with the exception of the PJM Western Hub contract introduced in April 2003.

[93] Derived from FERC EQR, Fourth Quarter 2002 through Second Quarter 2003. For more information on EQR data used in this report see footnote 5.

[94] Not all long-term contracts rely on long-term pricing. Many contracts reference short-term price indices.

Market Design and Price Transparency

Market designs varied from region to region during the assessment period, affecting the efficiency of electric market price outcomes. Several of these issues were raised in the market-by-market assessments above, but four aspects of market design are important to consider in greater detail:

- Price Transparency
- Economic Dispatch
- Seams and Geographical Variations
- Electricity-Natural Gas Interface

Each of these structural issues played out differently, with different effects on electric market performance. We consider them in turn.

Price Transparency

A transparent market is structured to provide market participants with easy access to each other, to products and to the price information needed to make efficient buy and sell decisions on a timely basis. Participants in wholesale electricity markets need to know what the prevailing price is, have an understanding of the process by which the price was formed and have a certain level of confidence that the price formation process is both credible and representative of the population of transactions taking place in the region. The scope and quality of available price information affects the ability of the market to produce a competitive outcome.

During the assessment period, about 65 percent of reported sales in the United States were for short-term energy,[95] but only a subset of these transactions was used to develop market pricing. Short-term transactions in ISO or RTO markets are systematically used to form market prices. In contrast, a subset of short-term bilateral transactions is used to develop various index published prices.

A key distinction between strictly bilateral and organized markets is the process for price formation and publication. It is the nature of electricity that minute-to-minute variations in demand, lack of electricity storage and lack of customer response to changing price conditions leads to wide variations in spot prices throughout the day. Customers within regions with organized markets have the opportunity to purchase electricity by the hour for the next day (day ahead) and in real time in open, transparent markets that provide explicit information on the locational price of energy, congestion and losses in each hour (often more frequently) of the day. Real-time and day-ahead prices for physical electricity are made transparent through the market-clearing prices posted on ISO or RTO websites. Day-ahead market prices are posted on the ISO or RTO website shortly after trading closes on the day prior to operation and delivery. Real-time prices are posted on the ISO or RTO website in almost real time. Although ISO day-ahead markets are a competitive alternative to day-ahead bilateral contracting, they also provide hourly options and pricing not available for most widely published bilateral contracts.

In contrast to hourly or more granular deals for ISO and RTO markets, customers in regions without organized markets purchase a block of 16 hours of on-peak (or off-peak) energy at a single price. Market participants can discover price terms for day-ahead electricity traded bilaterally at designated trading hubs by subscribing to trade publications, which collect transactional data from market participants to produce volume-weighted averages that represent the price of a commodity at a particular place and time. These indices are published after the end of the trading day. Prices in these regions reflect day-to-day and seasonal changes, but not the real-time changes in prices that reflect the time-varying cost of producing electricity. Confidence in survey-conducted indices was eroded early in the assessment period due to revelations of wash trading and allegations of misreporting transactions to the survey providers. However, even as these activities were rectified, structural issues of price opaqueness and inefficient dispatch remain. Further, because reporting is voluntary, it is not certain that the reported price information is representative of the totality of transactions executed.

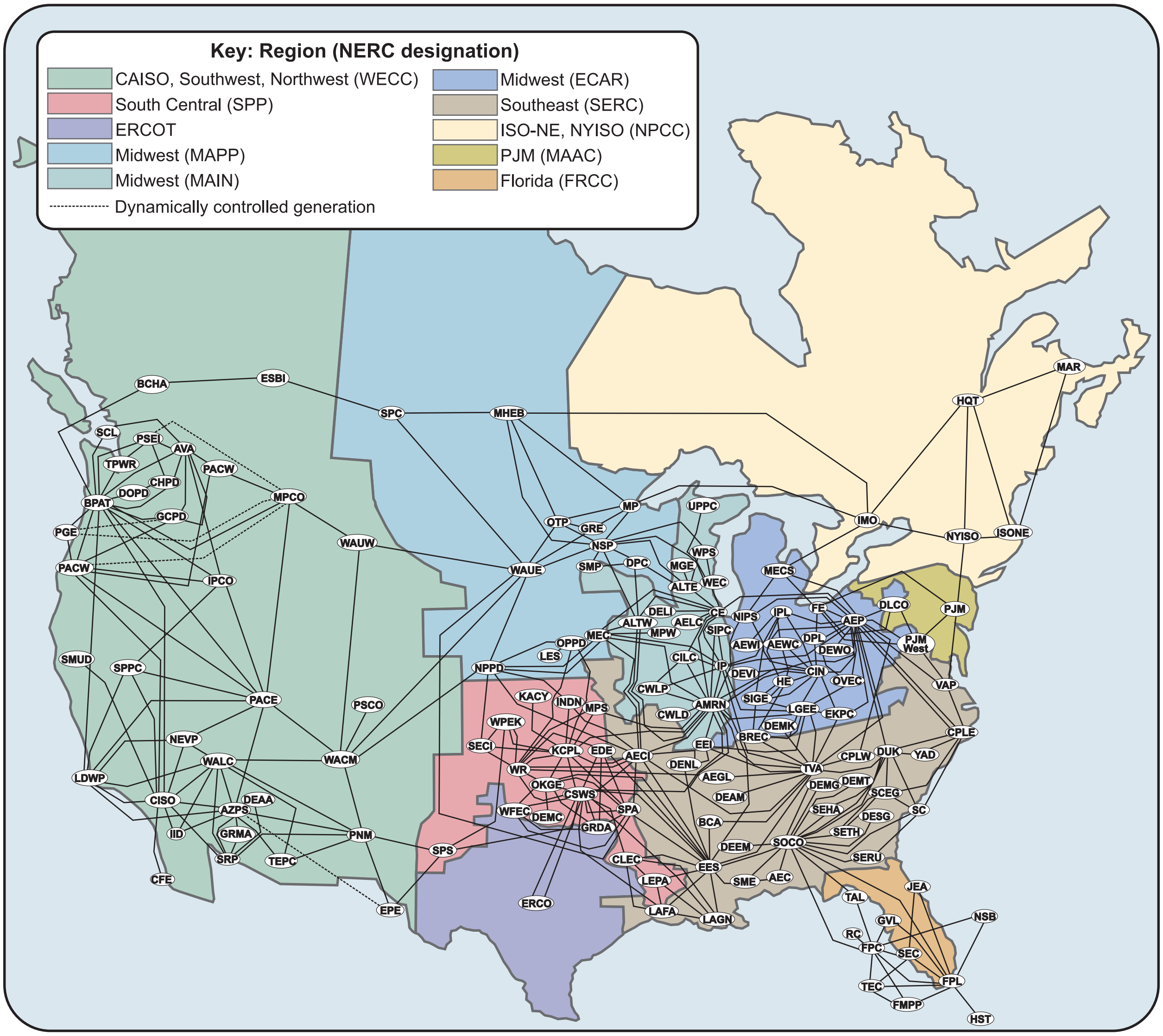
Economic Dispatch

Economic dispatch is a fundamental aspect of market design in organized markets. In these regions, prices are formed through well-defined regional economic dispatch processes.[96] The economic dispatch process schedules the least-cost mix of generation, based on offered prices, to reliably meet forecasted load subject to transmission capacity security constraints on economic dispatch. In addition to these constraints, most organized markets allow market participants to self-schedule their units. Some organized markets (e.g., ERCOT and CAISO) limit centralized economic dispatch to their real-time markets and rely entirely on market participants to optimize schedules in the day-ahead market. The economic dispatch process produces market-clearing locational prices equal to the marginal cost of supplying the next megawatt of energy to a particular

95 Includes sales made under short-term or spot contracts with terms of less than a year. Derived from FERC EQR, Fourth Quarter 2002 through Second Quarter 2003. For more information on EQR data used in this report see footnote 5.

96 This process is formally termed a bid-based security constrained commitment process that commits and dispatches generating plant in merit order (lowest to highest) of supply bids offered to meet forecasted demand with the required level of reliability and subject to transmission constraints.

Figure 32: Map of NERC control areas.



Note: Configuration as of August 1, 2003.

Source: NERC

location. These prices provide the customer with both the current price of energy and the financial effect of congestion on the transmission path.

In regions without organized markets, the price formation process was significantly less transparent during the assessment period. Price formation is, in part, a result of transmission and dispatch decisions, and the operation of the transmission system and dispatch of generating plants in these regions was under the control of multiple control area operators. Figure 32 designates control areas across the country with white circles. As can be seen, PJM operated two control areas and ERCOT operated a single control area. In contrast, there were in excess of 20 control areas in the Southeast.

As Table 14 indicates, in regions without ISOs there was not region-wide transmission scheduling or region-wide economic dispatch.[97] As a result, we cannot conclude that the most economic mix of generation in the region, given transmission constraints, was dispatched to serve customers in every region.

[97] A few of the regions without ISOs have hierarchical structures over local control areas that coordinate across control areas in a sub-zone of the region. For example, Southern Co. and Entergy have centralized operational control over the control areas operated by their subsidiaries.

Table 14: Selected design elements of energy markets, June 2003.

Legend:
■ = Yes
● = No
◆ = Not market based

Services Provided	Regions with organized markets					Regions without organized markets					
	ISO-NE	NYISO	PJM	ERCOT	CAISO	South-east	Florida	Midwest	South Central	South-west	North-west
Real-time energy market	■	■	■	■	■	●	●	●	●	●	●
Locational energy price	■	■	■	■	■	●	●	●	●	●	●
Hourly energy price	■	■	■	■	■	●	●	●	●	●	●
Congestion price	■	■	■	■	■	●	●	●	●	●	●
Losses price	■	■	● (1)	■	■ (2)	●	●	●	●	●	●
Regional transmission scheduling	■	■	■	■	■	●	●	■	●	●	●
Regional economic dispatch	■	■	■	■ (3)	■ (3)	●	●	●	●	●	●
Regional transmission planning	■	■	■	■	■	●	●	■	●	●	●
Regional interconnection process	■	■	■	■	■	●	●	■	●	●	●
Independent market monitor	■	■	■	■	■	●	●	■	●	●	●

Note: (1) Losses are allocated to market participants based on a pro-rata share of total transmission losses. (2) Losses are allocated to sellers using generation meter multipliers, which reflect scaled marginal losses. (3) CAISO and ERCOT did not have day-ahead energy markets; economic dispatch was used in their real-time balancing markets only.

Source: OMOI.

Only a few of the control areas in regions without organized markets have developed bilateral energy trading hubs, and only a few of these involve volumes of transactions that can be considered liquid (see Table 12). Illiquid trading and infrequently observed prices/trades created a non-transparent or opaque market. Further, there was only a weak correspondence between the prices at these few trading hubs and prices at the generation and consumption locations.

An example of the effect that the lack of locational signals associated with economic dispatch may have had on efficient operation can be found in the Southwest. Using market heat rate analysis,[98] OMOI estimated the likelihood that natural gas combined-cycle units (assumed to have heat rates of 7,000 Btu/kWh) could have been economically dispatched at key price points in the United States during the assessment period.[99] The analysis showed that in some markets estimated average capacity factors during the assessment period did not match the potential economic opportunity of dispatching natural gas combined-cycle plants based on the locational price signals indicated by market heat rates. For example, capacity factors for natural gas combined-cycle plants in the AZ-NM-SNV NERC subregion[100] averaged approximately 50 percent during the assessment period, even though the average market heat rate suggested these units could have been economically dispatched 94 percent of the time.[101]

ISO or RTO markets facilitated bilateral market transactions by providing one-stop shopping for energy balancing services throughout the region at competitive market prices. From the perspective of price formation, these spot markets provided a transparent, timely and credible reference price for bilateral contract negotiations. Prices and the price formation process must be sufficiently visible for market participants to decide whether the price is one around which they can make deals and enter bilateral contracts. ISO or RTO market prices serve as a benchmark and competitive alternative to bilateral contracts. For example, in regions such as New York, the prices of certain bilateral contracts settled at NYISO market prices. Participants in regions with organized markets were active in bilateral markets, with bilateral short-term and long-term contracts accounting for 40 to 90 percent of total sales in these regions.[102]

Effective access to wholesale markets requires timely communication of operational information, which is essential in markets that must instantaneously adjust supply to meet variations in demand. During the assessment period, communication of operational information varied significantly between regions without organized markets and markets operated by ISOs or RTOs. Within organized markets, key operational conditions such as the existence

[98] Heat rates reflect a measure of generating station thermal efficiency. It is computed by dividing the total Btu content of the fuel burned (or of heat released from a nuclear reactor) by net kilowatt-hours generated. Note that this analysis does not account for startup costs, no load costs or operating constraints.

[99] Derived from Platts Megawatt Daily information.

[100] Covers Arizona, New Mexico and Southern Nevada.

[101] Derived from Platts POWERdat information.

[102] Derived from FERC EQR, Fourth Quarter 2002 through Second Quarter 2003. For more information on EQR data used in this report see footnote 5.

of transmission congestion were conveyed through market prices. When transmission congestion occurs, delivery of more power from outside the constrained area is limited. Generating plants on the import side of the constraint must increase production or generating plants on the export side have to decrease production. These production increases and decreases are departures from the production schedule that is based on the economic dispatch of the lowest cost units, resulting in higher costs. When system operators and market participants cannot see the cost of congestion, they lack locational information that allows efficient dispatch and investment. During the assessment period, explicit and timely pricing of energy, congestion and losses by organized markets provided key information for generator dispatch decisions, buy-sell decisions and demand reduction strategies. It also provided information for transmission planning and investment decisions.

In regions where the location and price of congestion was not valued and published, the costs were spread to all customers regardless of cost causation. In these regions, price signals to relieve congestion and improve electricity service were muted or non-existent for transmission, generation and demand response operators and investors. Without explicit locational pricing of energy and congestion in regions without organized markets, we cannot rely on markets to identify and address constraints.

Regions with organized markets had responsibility for regional transmission planning and generation interconnection. However, where this responsibility was not coordinated among control area operators and market participants, or did not exist at all, price signals for investment were muted or distorted. It cannot be concluded definitively that regional planning and interconnection siting would have rationalized the twin problems of generation overbuilding and load pockets, because these processes were generally not in place at the time development decisions were being made for the projects added during the assessment period. However, there are several examples of how the lack of locational pricing and coordinated regional transmission planning led to excess generation where it was not needed, and the lack of transmission facilities to transport electricity to where it was needed.

The experience in the Western Interconnection (which includes CAISO, the Northwest and the Southwest) is a case in point. Although there was substantial activity regarding transmission planning needs underway during the assessment period, the region generally lacked a transparent, integrated transmission planning and siting process on a regional or subregional basis.[103] For example, 8,420 MW of new generation came on line in the period in the Southwest. Much of this capacity was in excess of the in-region load. However, energy exports from the Southwest to load centers in California were expected to increase by only 200 MW due to transmission constraints.[104] Similarly, new generation that came on line in Nevada and Arizona could not supply into load pockets of Las Vegas and Phoenix in certain hours due to transmission limitations. In Oregon and Washington, at the "I-5 corridor," new generation is under construction, but with concerns about transmission inadequacy. Additional new generation projects may not have been sited in Montana and Wyoming—a fuel-rich area—due to transmission limitations on delivering power to the load centers to the West.

The lack of coordination of generation and transmission was also evident in other regions without organized markets. Constraints that occurred on the transmission system around Atlanta required operational procedures to maintain reliability.[105] There is also currently a proceeding before the Commission regarding Entergy's process for evaluation of short-term transmission requests by generators.[106]

In summary, customers in regions without organized markets had significantly less market information about prices, price formation, system conditions and transmission infrastructure needs that ultimately affected prices than their counterparts in regions with these markets. During this assessment period, there was no effective price information regarding the value of electricity over time and across locations or of the regional needs for transmission and generation siting. This resulted in opaque or non-transparent prices, less efficient dispatch of power plants in these areas, use of less efficient congestion management tools and muted or distorted signals for investment where it was most needed.

The poor quality of information outside regions with organized markets limited the effective functioning of wholesale electric markets in those areas—which may have ultimately resulted in higher costs to customers.

Seams and Geographical Variations

In a grid system, there are geographical variations in electric prices due to differing market rules, generation costs, fuel mixes, transmission constraints and other considerations. It may be efficient to reduce these inter-regional price differences through investment in generation or transmission.[107] To the extent that these

103 Transmission facilities provide a service that is regional in nature. Transmission characteristics are such that upgrades to transmission facilities often support service in areas beyond and far from the local transmission facilities. The DOE, in its May 2002 National Transmission Grid Study, noted that transmission siting and permitting requires a coordinated regional approach since many transmission facilities cross state boundaries or land managed by one or more federal agencies.

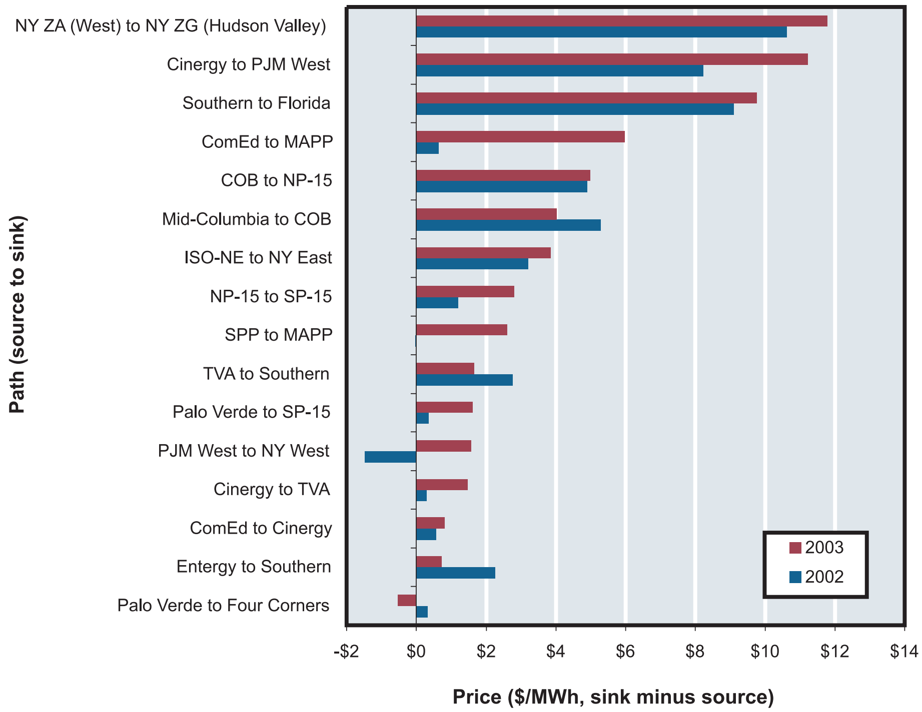
104 CAISO, 2003 Summer Assessment, Apr. 11, 2003.

105 SERC, 2003 Summer Assessment, May 2003.

106 Docket ER03-1272-000.

107 We will consider the market incentives for investment in a later subsection.

Figure 33: Inter-regional power price differentials vary.



Note: Annual comparisons based on January–September months only. Average (including positive and negative values) of day-ahead on-peak prices.

Source: Platts *Megawatt Daily*. Analysis and graphic by OMOI.

differences arise from differences in regulated market structures, such as different market rules for scheduling and dispatch of power, changes in market rules and regulations may be the best way to improve efficiency and bring benefits to customers.

During the assessment period, commerce between regions was often constrained by physical grid interconnection limitations. Figure 33 shows day-ahead, on-peak spot price differences in 2002 and 2003 for pairs of points from neighboring regions that faced these constraints.

During the assessment period, commerce between regions was also constrained for non-physical reasons, called "seams." Power products and differences in pricing and market rules can differ significantly between ISO and RTO markets and result in reduced competition between suppliers across regional boundaries. These differences include:

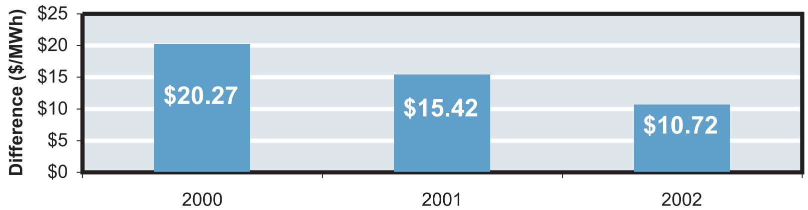
- Export charges
- Differences in schedule times, ramp rates and protocols
- Capacity market differences in installed capacity (ICAP) definitions, requirements, deliverability and recall procedures

In addition, inconsistent treatment of transmission service products across multiple control areas, curtailment of transactions due to data incompatibilities and inconsistencies in ATC calculations and information posting may also reduce competition.

Resolving these types of seams differences between regions could lower the cost of transacting power sales between regions, permit dispatch of lower cost power and ultimately lower costs to customers. When neighboring regions have RTO or ISO markets, the regions can work together to revise rules and to improve market pricing at the seams. However, when one region has an RTO or ISO market and one does not, efficient pricing becomes more difficult to achieve, because there is no organized framework for addressing these types of differences.

Prices at the seam between ISO-NE and NYISO illustrate the significance of these seams differences. Figure 34 shows the average differences for 2000–2002 between the ISO-NE and NYISO when the interface was not congested. The consistent year-on-year reductions, from $20.27 in 2000 to $10.72 in 2002, indicate significant progress in reducing price differences, but the remaining difference of $10.72/MWh in 2002 still leaves considerable room for improvement. The

Figure 34: New England-New York price differential narrows.



Note: Average of absolute value of price difference between NYISO and ISO-NE in uncongested hours.

Source: *Virtual Regional Dispatch: Concept, Evaluation, and Proposal*, Joint Working Paper, ISO New England, Inc. and New York ISO, Inc., Appendix D, p. 20. Analysis and graphic by OMOI.

NYISO market adviser estimates that efficient dispatch across the seams could have saved NYISO customers $175 million per year, approximately 6 percent of their total bill.[108]

When an ISO or RTO operating an organized market with LMP borders an area without an organized market with only bilateral trading and transmission pricing based on contract path charges, impediments to price convergence cannot be addressed by agreements between two ISO/RTOs. In these cases, pricing at the interfaces between the regions can send misleading signals that do not reflect the actual congestion caused by the underlying power trading activity. Prices at multiple interfaces can lead to distorted congestion pricing and unscheduled flow problems for the importing RTO. PJM experienced these problems in 2002 when it expanded by adding PJM West, reflected in increased differences between reference prices at the western AEP interface and the southern VAP (Dominion-Virginia Power) interface. As a result, the range of prices across the interfaces to the west and the south increased dramatically from less than $1/MWh before the addition of PJM West to $4 and higher afterwards. These differences show how the contract path approach in neighboring regions can undermine the efficiency of LMP dispatch if LMP pricing at regional interfaces is not properly designed.

The single reference bus pricing approach, now used in PJM for the AEP and VAP interfaces to address the problem, removes much of the ability to create artificial prices at these external locations, but does not fully reflect the corresponding external conditions. Only a single combined RTO or the development of a common power market across the region would provide that level of pricing accuracy. PJM and MISO have begun the development of a common market through a joint operating agreement (JOA), which will be in place when MISO begins the operation of its organized market.

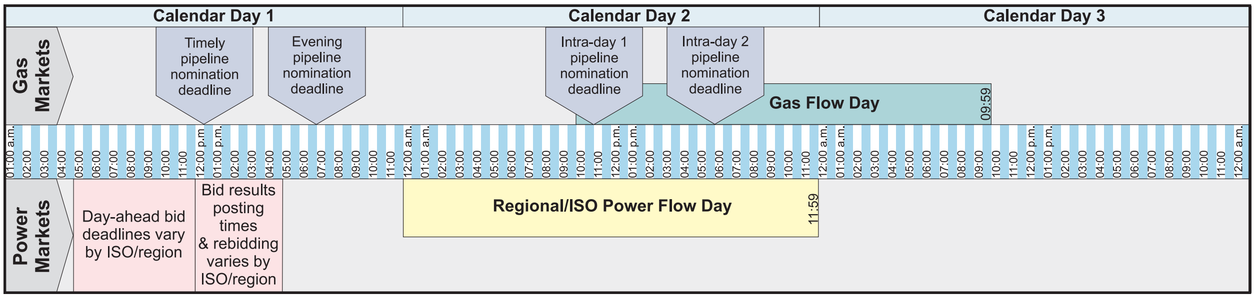
For the past several years, the organized markets in the Northeast have undertaken a series of projects designed to reduce the seams among the RTOs and ISOs, known as the Northeast Seams Initiative. This initiative is intended to harmonize market rules, eliminate seams and develop larger markets among ISO-NE, NYISO, PJM and the Ontario IMO. There are several current open seams projects intended to address the causes of these price differences, including NYISO real time scheduling (RTS) that will replace existing NYISO software and move scheduling toward shorter time intervals and greater consistency with the current ISO-NE market design. Other projects include improvements in reserve sharing and NYISO transmission contract options for external interfaces. The NYISO Independent Market Advisor has proposed revisions to the regional dispatch, known as the virtual regional dispatch (VRD) proposal, where the RTOs would adjust schedules in real time to move prices in NYISO and ISO-NE closer together. This proposal has raised concerns with some participants, but the continuation of significant price differences is an indication of the continuing need to find better ways to achieve savings through more efficient interregional dispatch. OMOI will assess the effectiveness of these projects.

Electricity-Natural Gas Interface

As shown in Figure 35, seams also existed between natural gas and power markets during the assessment period. Owner/operators of gas-fired generating capacity encountered transactional burdens because key market rules affecting the operations of the gas and power industries were not fully aligned. Time periods, for example, defining the "gas day"

108 Based on an estimate for 2002 presented by Potomac Economics to the Joint NYISO Market Structure Working Group and the ISO-NE Markets Committee, titled "Estimated Savings from Virtual Regional Dispatch." Although prepared as an estimate of savings from Virtual Regional Dispatch, this analysis applies equally to any market changes that result in successful arbitrage across the NYISO/ISO-NE seam. The analysis is based on the assumption that all customers taking service in the NYISO spot market benefit from the pricing improvements. The percentage savings estimate is based on the total NYISO spot market receivables ($3.1 billion for 2002) reported in the NYISO Monthly Report for July 2003

Figure 35: Gas scheduling and power bidding timelines vary.



Notes: All times are Eastern Standard Time.

Source: Based on tariff terms and conditions for FERC-regulated gas pipeline tariffs and ISO/RTOs. Graphic by OMOI.

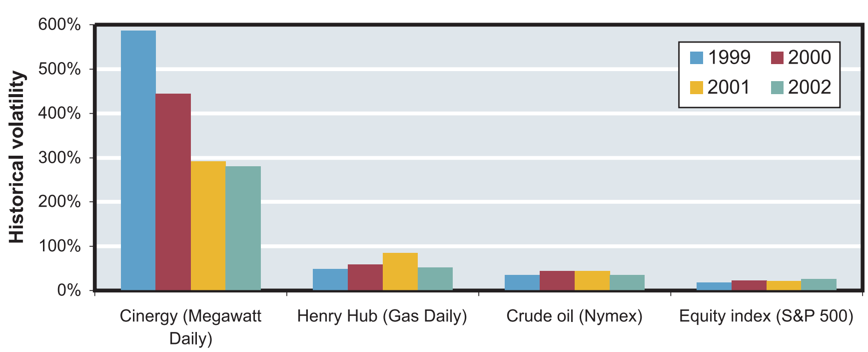
and the "power day" varied by market. According to business practices adopted by the North American Energy Standards Board (NAESB) Wholesale Gas Quadrant Committee and incorporated by reference into FERC jurisdictional interstate natural gas pipeline tariffs, the term "gas day" always means a period of 24 consecutive hours, beginning at 10:00 a.m. Eastern Standard Time. However, the definition of the 24-hour period comprising the "power day" usually begins around midnight and may vary slightly by market. Further, although uniform minimum standards exist for when gas market participates nominate and schedule gas on interstate pipelines, similar standards related to bidding and scheduling power do not exist in bilateral markets, ISOs or RTOs.[109]

Risk Management

The ability to manage risk effectively is a critical element of well functioning markets. Although market participants must deal with many different kinds of risks, e.g., price, credit, operational and regulatory risks, our discussion focuses primarily on price risk management. Risk management in the electric markets involves various forms of financial instruments for hedging in the long-term bilateral markets as well as products offered in the short-term organized markets.

Price risk management is, in many ways, an explicit strategy to manage exposure to volatility. Because electricity cannot be stored easily, power prices are among the most volatile of all commodities (see Figure 36). However, annualized volatility declined during the assessment period in most major power markets. The decrease in volatility was not necessarily a consequence of improved price risk management but more likely a result of changing fundamentals (e.g., higher reserve margins) in power markets. (In contrast, volatility of natural gas prices has increased as discussed later in the report.)

Figure 36: Power price volatility tops all major commodities.



Note: Annualized historical volatility is calculated as the standard deviation of logarithmic returns, log ($price_t$ /$price_{t-1}$), where standard deviation is based on all trading days (weekdays excluding holidays) during the calendar year. S&P 500 is provided for comparison.

Sources: Bloomberg, Platts Gas Daily and Platts *Megawatt Daily*. Analysis and graphic by OMOI.

109 In late 2003, NAESB formed the Gas Electric Coordination Task Force to address seams between gas and electric markets.

The development of risk management options slowed after the Enron bankruptcy in December 2001 and subsequent events including accounting and trading scandals, credit rating downgrades and price misreporting for published indices all contributed to a loss of confidence in the industry. Most significant perhaps was the decrease in number of creditworthy counterparties. However, there were many new developments as well, including the entry of new financial players into the business, efforts to address credit issues, clarification of rules for mark-to-market accounting, new risk management policies (e.g., the CCRO initiative) and coordinated efforts between FERC and the CFTC to prosecute violators of established rules.

Organized markets have been helpful in improving the choices available for risk management activities. Besides offering products such as financial transmission rights (FTRs) for managing price risk due to transmission congestion and the definition of trading hubs to improve long-term hedging, organized markets also offer transparent hourly prices that can be used in writing financial swaps. Settlement specifications for financial swaps in organized markets are indexed to publicly available day-ahead or real-time prices of the organized markets.[110] In regions without organized markets, a similar index might only be available from published surveys and lacks the same level of confidence and transparency.

Despite the benefits of organized markets, the lack of long-term price transparency remains a problem common to both organized and unorganized markets. Even within organized markets, the liquidity of forward price quotes can vary considerably. Often this depends on the maturity of the market and the perceived sense of stability in market rules.

Forward Contracts

Forward physical and financial transactions for electricity are contracts designed for delivery beyond the day-ahead or real-time markets. Forwards are often traded in the OTC market using voice brokers or online OTC exchanges like ICE, or through direct bilateral transactions.

With the exception of ICE, there were no transparent, organized markets for transacting physical, long-term electricity contracts (typically contracts that cover electricity delivery over a period of one year or more) during the assessment period.111 Lack of information about long-term electricity contracts and prices makes it difficult and costly to develop a forward price curve to analyze the profitability of potential investments. Forward price curves allow a market participant to lock into buying or selling spot energy at a future date at the forward price. During the assessment period *Megawatt Daily* did provide long-term prices for specific markets, but it is not clear how much volume was transacted at these prices.

ICE also supports trading of financial electricity products. During 2003, the primary electricity financial product on ICE was a swap during peak hours. A swap is an agreement where counterparties exchange a floating energy price for a fixed energy price. Swaps are also known as contracts for differences or fixed-for-floating contracts. The floating price in a financial swap is based on an index. In organized markets, spot indices published by the ISO or RTO are increasingly being used as the floating index in swaps. In unorganized markets, spot indices available from surveys may be used or counterparties may prefer to enter into forward contracts that do not require an index.

Financial swaps were bid, offered or transacted at 15 different locations on ICE for a range of tenure from the balance of day to the calendar year 2006. ICE does define products in regions with and without organized markets. The majority of the financial swap volume transacted during April 2003 through October 2003[112] was at the New England pool, New York Zones A (West), G (Hudson Valley) and J (New York City) and PJM Western Hub. The financial products traded on ICE have been defined at many locations, but were transacted primarily at locations where there is an organized underlying physical market during the April 2003 through October 2003 period.

Electricity Futures and Over-the-Counter Products on Nymex

Trading of electricity futures contracts remained only partially developed during the assessment period. Nymex futures contracts for electricity began in March 1996 with the Palo Verde (in Arizona) and California/Oregon Border (COB) delivery points. The Nymex contracts were originally specified with volumetric contract units of 736 MWh of electricity.[113] For any contracts not closed out prior to the monthly expiration, the delivery rate was two MW for each on-peak hour. Following the two initial electricity futures contracts, Nymex introduced four additional electricity contracts between 1998 and 2000. The other futures contracts delivery points were Cinergy and Entergy in 1998, PJM in 1999 and Mid-Columbia in 2000.

110 Nymex website.

111 Nymex offers a PJM monthly futures contract and New York ISO Zone A (West), Zone G (Hudson Valley) and Zone J (New York City) locational based marginal pricing swaps. The PJM futures contract and New York ISO Zone A, G, and J swaps are offered for a period of more than one year and are financially, not physically settled.

112 Although electricity trading was conducted prior to April 2003, the volume data for financial transactions available to OMOI at this time are incomplete.

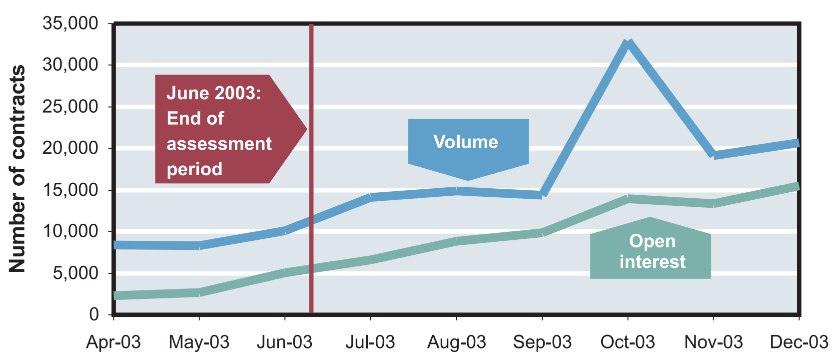
113 In 1998, the contract size was changed to 864 MWh. In 1999, the contract size was split in half to 432 MWh with an hourly delivery rate of 1 megawatt per hour. The change to 1 megawatt per hour was to make it easier to use the contract to hedge standard physical contracts of 25 MW per hour.

For several years after the contracts were introduced the volume of trading increased. In October 1997, the number of Palo Verde futures contracts traded was 110,858 contracts, up from 17,548 contracts in 1996. For the same time period, the number of COB contracts traded was 83,618, up from 52,346 in 1996.[114] Ultimately, however, the use of Nymex electricity futures declined, and did not achieve the same success as the Nymex Henry Hub natural gas futures contract. After volume in the contracts dried up, all six electricity futures contracts were delisted (taken off the exchange) in early 2002.

There were several reasons for why industry participants may have stopped using the futures contracts. The size of the contract specifications did not match well against the standard size of wholesale physical transactions. The set size of the monthly total number of megawatt hours in each futures contract did not account for the varying number of peak days in each month. Additionally, due to the regional nature of the electricity market, it was difficult to use the futures contract delivery settlement price plus or minus a basis as a price for other regions. This is unlike the Henry Hub natural gas futures contract that is used within pricing formulas for regions across the country. The electricity futures contracts have to be set up for each of multiple regions where there is an underlying forward physical market.

After delisting the original electricity futures contracts, in December 2002 Nymex proposed three new futures contracts at PJM with redesigned contract specifications. The contracts are for daily, weekly and monthly periods. The three new futures contracts launched in April 2003 (for the monthly contract) and June 2003 (for the daily and weekly contracts) are different from the original electricity contracts in two respects. First, the contract size changed and second, the contract became financially, not physically settled. The daily unit size of the redesigned standardized Nymex contract is 40 MWh; the volume for the monthly contract must be in multiples of the number of peak days in each month. Financial settlement is based upon the arithmetic average of the PJM Western Hub real-time locational marginal pricing for the 16 peak hours of each peak day. The number of contracts transacted per month and the open interest at the end of each month for the PJM Western Hub monthly futures contract through October 2003 is shown in Figure 37. Figure 38 shows the settlement prices for the next-month PJM Western Hub futures contract during the assessment period and extending into summer and fall 2003.

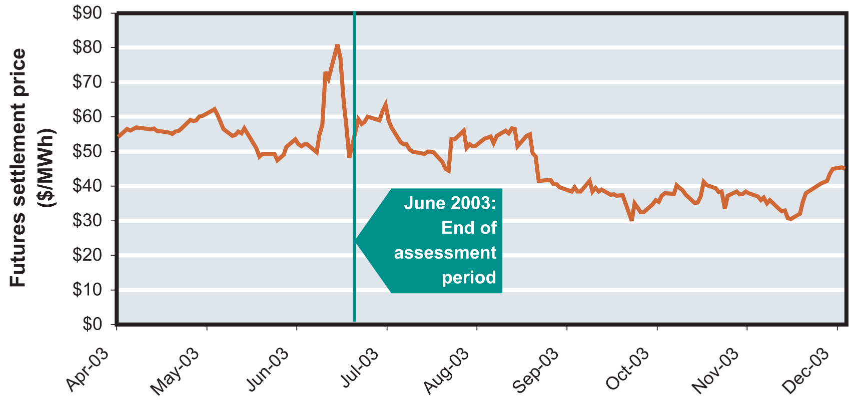
Figure 37: PJM futures volume and open interest increase.



Source: Nymex. Analysis and graphic by OMOI.

[114] Nymex, "Nymex Sets Volume Records," Press release, 10/2/1997.

Figure 38: PJM futures prices follow seasonal patterns.



Source: Bloomberg, LP. Analysis and graphic by OMOI.

In addition to the new electricity futures contract, Nymex began clearing standardized electricity contracts in May 2002. Credit clearing is a mechanism for settling mutual claims, the result of which is that the risk that a company might fail to fulfill its contract is pooled among many companies. This lowers the risk of entering the transaction, thus reducing the cost of the transaction and the credit exposure faced by each trading entity. The clearing capability allows market participants to transfer their counterparty credit risk on transactions to Nymex.[115] During the assessment period, the electricity clearing locations included Palo Verde, Mid-Columbia and PJM for physical, not financially settled contracts.

Nymex expanded the list of its OTC electricity locations available for both clearing and trading with the start of its ClearPort platform in 2003. The ClearPort platform is an Internet site where standardized OTC products are cleared and specified OTC swaps and futures are both cleared and traded. The OTC electricity products that are cleared and traded are New York ISO Zone A (West), Zone G (Hudson Valley) and Zone J (New York City) locational based marginal pricing swaps. The PJM daily, weekly, and monthly futures contracts are also available on the ClearPort platform. Transactions not executed on Nymex that meet the product specifications can also be brought to the ClearPort platform for clearing. From May 2002 through October 1, 2003, the equivalent of 73.6 million MWhs of electricity has cleared through Nymex's clearinghouse.[116]

Next we discuss some of the products and services that were introduced for managing different kinds of risk in the short term organized markets.

Virtual Bidding

Virtual bidding is a risk management tool offered in NYISO, PJM and ISO-NE to help convergence of day-ahead and real-time prices. A virtual demand bid involves a day-ahead purchase that is sold back in the real-time market as a price taker without any actual consumption of power. A virtual supply offer involves a day-ahead sale that is bought back in real time without any actual supply of power. In this sense virtual bids and offers are essentially financial swaps between the day-ahead and real-time prices.

Virtual bidding allows participants to hedge against the risk that real-time and day-ahead prices will differ. Virtual bidding eliminates the need to physically withhold supply in the day-ahead market if a seller anticipates the real-time price to be higher than the day-ahead price. It also allows market participants to speculate on the difference between day-ahead and real-time prices. Virtual bids and offers are open to financially qualified participants regardless of whether they own physical assets or have load-serving obligations. Though purely financial, virtual bids and offers do affect physical day-ahead energy prices. Accepted virtual bids and offers are placed in the day-ahead supply and demand curves just like physical bids and offers from generators and loads. Other than satisfying the credit requirements, there are no barriers to entry for a virtual trader.

The volume of virtual bidding in NYISO increased in 2002 with virtual bids and offers setting price in many hours. In ISO-NE, the volume of virtual bidding declined. This is partly related to the allocation of PUSH and RMR uplift costs to real-time deviations (i.e., the day-ahead and real-time price difference must be greater than the expected uplift for there to be any incentives for arbitrage through virtual bidding).

115 Nymex clearing is done via the Nymex Clearing House that is a registered Derivatives Clearing Organization with the Commodities Futures Trading Commission.

116 Nymex, Press Release, "Exchange Clears 5 Millionth Contract Through Nymex ClearPort," 10/1/03.

Trading Hubs

Fungible long-term products allow for long-term hedging to reduce commodity price risk. In order to develop standardized trading products in an LMP-based market, trading hubs can be defined to foster liquidity in the forward markets. In general, the hub price is a weighted average of individual node prices. Nodes are typically selected using statistical analysis to choose a set of nodes where price changes are positively correlated and relatively stable with respect to local congestion. The expectation is that by including an average of prices across a large number of buses, movements of the price at the resulting virtual hub would be more representative of movements of the prices in the market. The earliest and perhaps best known example of such a trading hub is the PJM Western Hub which consists of 111 individual nodes. In contrast, the PJM Eastern Hub which was defined using similar analysis did not turn out to be as widely traded.

During the assessment period, ISO-NE introduced a trading hub (the NEPOOL hub) as it implemented LMP. The NEPOOL hub is comprised of a selection of 32 representative nodes: five are 345 kV, one node is 230 kV and the remaining nodes are 115 kV buses. The hub price is the simple average of the 32 node prices. Experiences with this hub were mixed. Prior to the introduction of LMP, uncertainty about the hub definition once LMP was implemented appears to have had an adverse affect on liquidity in the bilateral markets. Once the LMP-based markets commenced operation, there was some congestion within the hub that caused ISO-NE to consider re-evaluating the hub specification. In many cases, congestion occurred only in the day-ahead market, often as a consequence of virtual bidding. However, such artificial congestion in the day-ahead market that did not persist in real time may be the result of ineffective use of virtual bidding.

Financial Transmission Rights

LMP-based congestion management reduces TLR risk and introduces price risks for transmission customers that reflect LMP differences between sources and sinks. Unlike the exposure to TLRs, LMP-based price risks can be hedged through instruments known as financial transmission rights (FTRs). There are many different kinds of FTRs which have been used in NYISO and PJM for a few years. The most basic instrument is a point-to-point obligation where the FTR holder either receives or must pay (if negative) the LMP difference between pre-defined points of receipt and delivery. The payoff for such an FTR would exactly offset the price risk for a transaction between the corresponding points of receipt and delivery. A point-to-point FTR does not necessarily correspond to physical elements of the transmission grid.

Another important type of FTR is a flowgate FTR. Unlike point-to-point FTRs, flowgate FTRs are associated with actual physical elements of the transmission grid and entitle the holder to receive revenues based on the shadow prices of flowgate constraints as established in the solution to the security constrained unit commitment used to set LMPs. While there can be a very large number of point-to-point FTRs corresponding to different points of receipt and delivery in the transmission grid, the number of congested flowgates in any system is typically much smaller.[117] This can make flowgate FTRs useful for facilitating secondary markets. There is little actual experience with flowgate-based FTRs except for interzonal FTRs in CAISO and ERCOT that are variants of flowgates. The Midwest ISO plans to include flowgate FTRs when it commences operation of its LMP-based markets.

FTR options are a form of FTRs that entitle their holders to receive only positive revenues (with no liability when values are negative). In early-2003, PJM successfully conducted an FTR auction where both point-to-point options and point-to-point obligations were made available to market participants in on-peak, off-peak and 24-hour FTRs. The auction had four rounds, and 50 participants submitted more than 600,000 bids.

An important measure of the hedging value of FTRs is the level of payout that can be guaranteed once an FTR is issued. In general, the revenue collected from LMPs is equal to or greater than what is required to pay FTR holders as long as the FTR allocation is “simultaneously feasible” with respect to the ratings and limits of the transmission system. In some instances, these ratings can change after FTRs have been issued (e.g., line derates and outages) causing an insufficiency in revenues to pay off all FTR holders. In some markets (e.g., NYISO), full payout is guaranteed but requires market participants to pay an uplift. In other markets (e.g., PJM), the payout of FTRs is reduced proportionally. In 2002, PJM FTRs had a payout of approximately 95 percent, which was slightly higher than the payout in 2001.

Table 15 summarizes key design elements in the different FTR markets that are currently in operation or are under consideration.

[117] In an N node network, there can be as many as 2N (N-1) point-to-point FTRs for N > 2. Thus for a 100 node network, there can be 19,800 possible point-to-point combinations for FTRs.

Table 15: Design elements of FTR markets.

Market	Physical/ financial	Type of FTR	Fully funded	Level of existing contracts	Length	Initial auction
ISO-NE	Financial	Point-to-point and point-to-hub obligations	Yes	Low	Single month	Yes with auction revenues allocated to LSEs/ ARR holders
NYISO	Financial	Point-to-point and point-to-zone obligations	Yes	Low	Single month, whole year and multi-year	Yes, with auction revenues allocated to Transmission Owners
PJM	Financial	Point-to-point obligations and options	No	Low	Single month and whole year	Yes
CAISO (under MD02)	Financial (with scheduling priority)	Point-to-point obligations	No	High	Single month and whole year	No
MISO (under development)	Financial	Point-to-point and flowgate FTRs, options and obligations	Yes	High	Single month and whole year	No

Source: OMOI.

RTO Credit Policies

Credit risk management in organized markets has evolved with special credit requirements for some products, e.g., virtual bidding and FTRs where the holder may have to pay the RTO or ISO if LMP differences are negative. In general, however, credit risk in organized markets is socialized where shortfalls after default are allocated among the remaining participants in a pre-determined manner. Due to the shortcomings of this approach, some RTOs and ISOs have begun looking at alternatives such as credit risk insurance, accelerated cash settlements and other solutions to deal with shortcomings of the current system. The details of credit policies in RTOs and ISOs can vary in terms of collateral requirements, credit limits, cure periods etc. The credit limits are based largely on historical usage patterns. Billing cycles continue to remain a major factor for credit requirements in RTO and ISO spot markets.

Infrastructure Investment

Investment in electric infrastructure increased generation capacity by 10 percent from January 2002 through June 2003. Of the 85 GW that entered commercial operation during the assessment period, 96 percent was gas fired.[118] Much of this investment proceeded based on decisions made during the period of high energy prices before the assessment period. Most of this investment was made in generation, predominantly by merchant companies, with only a small amount made in transmission, predominantly by regulated entities. Ten of the most active of these companies, which include energy merchants and convergence companies, spent $28.5 billion to finance construction of 60 GW, or roughly 42 percent of new capacity installed from 1998 through 2002.[119] Investors and not end-use customers assumed the risks in the search for attractive returns, which were largely unrealized on these unregulated generation investments during the assessment period.

Generation investment increased reserve margins lowering the capacity prices that typically provide a significant proportion of generator revenues.[120] In addition, in a market with stable or declining electricity prices, gas price increases led to lower spark spreads for many gas-fired generators, cutting net revenues from energy sales. As a consequence, revenue tests conducted based on observed energy prices in 2002 and 2003 indicate that new investment would not have been, or would have been marginally, profitable in most regions. Nevertheless, in certain load pockets, prices continued to signal the need for new construction.

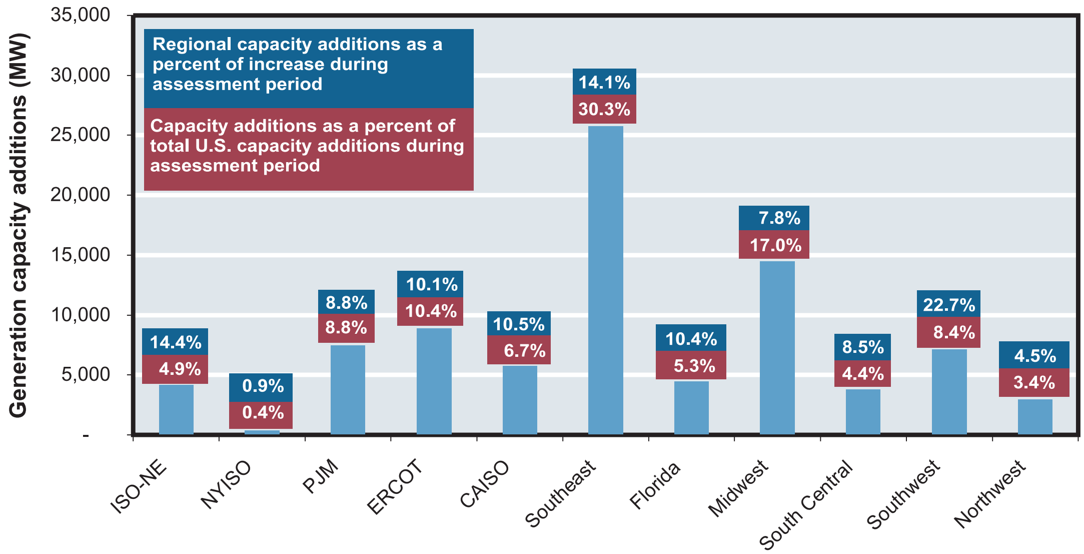
Several factors affect investment decisions and the returns on investment in the electric sector including:

118 Derived from Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

119 Deutsche Bank Securities, Factset, includes AES, Aquila, Calpine, Dynegy, El Paso, Edison Mission Energy, Mirant, NRG, Reliant Resources and Williams.

120 Typical project finance structures rely on contracted capacity payments to pay for fixed project costs including debt service. Capacity markets in regions with organized markets saw price declines during the assessment period. For example, according to the PJM State of the Markets Report, capacity prices fell from $67.20/MW-day to $12.50/MW-day between January and December 2002. NYISO estimates that ICAP revenues would have represented 41 percent of the revenues for a 7,000 Btu/kWh generator in Long Island from September 2002 through August 2003 and 51 percent of the revenue of a New York City generator of the same heat rate, declining from 52 percent of revenues on Long Island and 61 percent in New York City, respectively, from September 2001 through August 2002.

Figure 39: New additions increase U.S. capacity by 10 percent.



Source: EIA, Form 860, Annual Electric Generator Report. Analysis and graphic by OMOI.

- current and forecasted prices,
- potential and actual bid mitigation,
- local opposition to construction,
- financial conditions of the developers, and
- policies of transmission operators.

This section focuses on the price signals markets provided during the assessment period for when and where investment was needed. It addresses the following areas:

- Generation Investments
- Investment Opportunities
- Investment Opportunities in Load Pockets
- Demand Response as an Investment Alternative
- Transmission Investment
- General Investment Conditions

Generation Investments

Reserve margin and load data suggest that there were adequate, or in some cases, excess resources and reserves to meet regional demand during the assessment period. Reserve margins, which run from a low of 13 percent in PJM to 40 percent in the Northwest, are shown in Appendix 2. However load pockets persisted in subregions where the capability to import needed lower cost power was significantly constrained, and the overall regional reserve margin did not identify such investment requirements.

Wholesale customers reaped the benefit of the surplus generation situation during the assessment period through lower and more stable prices. The lag time between price signals and the ability to site, license, finance and construct new capacity meant decisions made by producers based on price signals sent in 1999 through 2001 led to capacity additions made during 2002 and 2003. Adequate, and in some cases more than adequate, generating capacity coupled with low demand growth resulting from the economic downturn and mild weather contributed to lower energy prices in the assessment period than in previous periods.

As seen in Figure 39, about 30 percent of total U.S. generating capacity additions during the period was in the Southeast. New additions in the Midwest were 17 percent of the total, with ERCOT completing about 10 percent of total U.S. additions to generating capacity during the period. ISO-NE, the Southwest, CAISO and Florida also saw significant increases to regional generating capacity.

In some of these regions, ERCOT and ISO-NE in particular, significant capacity additions were made to already comfortable reserve margins (originally 31 percent and 17 percent, respectively). Some merchant generators assumed open access and built capacity, in many cases not due to its proximity to load or in areas of low reserve margins, but where it was easiest to build, where there was access to gas supply or where tax and other incentives were offered.

Merchants owned or operated approximately 85 percent of the gas-fired capacity placed into service during this period.[121] Because the investment was made outside of the regulated rate base, investors rather than end-use customers bore the brunt of the losses of the "bust" portion of the current cycle. As will be seen below, market prices in many regions were likely not sufficient in 2002 and 2003 to meet equity payments, and in some cases even debt payments, on the generation investment. Competitive pressures held down wholesale prices. However, the degree to which these lower prices accrued to retail customers depends on particular state-level regulatory and market structures.

Investment Opportunities

Prices in well-functioning markets should attract and retain needed investment when and where needed. The profitability of investment during the assessment period varied from region to region and was influenced by market design. Net revenue, or estimated market revenue less estimated variable operating costs, indicates the extent to which markets support recovery of the fixed costs of investment and a profit. New investments and operating facilities are sustainable when they earn revenues sufficient to cover both marginal costs and fixed costs (including fixed operations and maintenance costs, interest payments, taxes and depreciation) and provide an attractive return on equity. Net revenue will vary in the short term due to changes in fuel prices, weather, outages, exercise of market power or regulatory market power mitigation. Over the longer term, revenues will vary as temporary shortages or surpluses reflect the entry and exit of generating facilities. Thus investors consider the revenue streams over a period of time approximating the useful life of the assets (measurable in decades) and within the context of the region's resource adequacy.[122] Net revenue and spark spread analyses are useful investment signals used by market participants in conjunction with other analyses, including net present value, financing and real option models. While this study concentrates on historical observed prices, investors rely heavily upon projected future results based on revenues and costs driven by assumptions of future demand and supply growth. This growth is affected by changes in regional economies and energy intensity, regulatory structures, plant retirements and expansions, environmental regulations and the costs of equity and debt capital.

To assess the degree to which electricity markets may sustain current investment and attract new entry in regions and constrained areas where it is needed, OMOI used three market revenue tests:

- OMOI asked the NYISO, ISO-NE, PJM and CAISO MMUs to calculate net revenues that a hypothetical combined-cycle plant would earn in each market during the assessment period region-wide and in constrained areas based on locational revenues and differences in costs.
- For regions without organized markets, OMOI conducted spark spread/profitability regional analyses to gauge the likelihood that a new, efficient 500-MW natural gas-fired combined-cycle plant would be called upon to run, and whether revenues would be sufficient to cover fuel costs, pay debt service and equity returns.
- A demand response analysis measured the profitability of investment in demand response in both organized and bilateral markets.

In the first or net revenue analysis, revenues included energy market revenue, capacity market revenue if applicable, ancillary service payments and uplift payments.[123] The analysis was performed for system-wide prices and for selected load pockets. The net revenue, calculated by ISOs for their markets, was compared by OMOI to costs of construction estimated by the MMUs for their respective markets for a combined-cycle plant ranging from $81 to $115/kW-year.[124]

The results using system-wide prices from organized markets are shown in Table 16. Positive values indicate that revenues would have been sufficient to cover variable costs as well as fixed costs and begin to provide equity returns. Negative values indicate revenues insufficient to cover all fixed costs. The tests suggest that prices signaled need for new construction in CAISO's regional markets and in NYISO's Hudson Valley region. Prices do not suggest investment in ERCOT, ISO-NE or PJM. The test reflects need for projects to

121 Derived from Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

122 OMOI's examination indicated that net revenues in 2001 were higher than during the assessment period. OMOI will use this information as a baseline for continued monitoring.

123 Energy market revenues are based on region-wide electricity prices and the daily natural gas price reported for representative pricing points in the region. Capacity payments are based on capacity auction averages; ancillary service and uplift payments are estimated as a pro-rata share of the total. OMOI provided the MMUs with common assumptions for variable costs and operation of a hypothetical combined-cycle unit, including: 7,000 Btu/kWh heat rate, $1/MWh variable O&M cost, 5 percent forced outage rate and unit dispatch whenever LMP is greater than or equal to variable cost.

124 Levelized annual revenue requirements for generators depend on several inputs, including: installed cost, project life, debt/equity ratio, tax rate, interest rate on debt, return on equity and fixed O&M charges, and these vary by location and technology type. Each MMU provided an annual revenue requirement on a $/kW-year basis for a combined-cycle baseload plant to derive the net revenues in their markets: PJM provided $81/kW-year, ISO-NE, $115/kW-year and the NYISO, $99.50/kW-year for outside of New York City. The CAISO provided a range of between $70 and $90/kW-year and OMOI has shown the analysis using costs of $90/kW-year for CAISO. These figures compare with a national cost of $90/kW-year provided by Pace Global Energy Services in Mind the Gap, Project Finance, July 2003.

pay off debt service and provide an equity return to signal investment, but access to and costs of the capital markets vary over time. Under current capital market conditions, lenders require revenues that exceed debt service costs by several times for projects without long-term fixed price contracts earning revenue based on bilateral or spot market sales. Equity sponsors may require higher equity hurdle rates.[125]

Table 16: Profitability indicated for CAISO and NYISO investment.

Area	Net revenue in ISO day-ahead market ($/kW-year)
ISO-NE	-$18.8
NYISO (Hudson Valley)	$35.8
PJM (1)	-$9.8
ERCOT	-$60.3
CAISO (SP-15)	$87.8
CAISO (NP-15)	$81.7

Note: Year ending June 30, 2003. Break-even operations would earn net revenue of zero. See footnote 124. (1) PJM's analysis used calendar year 2002 data and cannot be directly compared to the other regional analyses

Source: ISO-NE, CAISO, PJM, NYISO, ERCOT.

The second test was spark spread/profitability analysis for the regions without organized markets, which, while similar in concept to the net revenue test employed for the organized markets, relies solely on revenues from energy sales in each regions' spot (i.e., day-ahead) bilateral energy markets.[126] This analysis assumes that units are dispatched if reported bilateral electricity prices exceed fuel costs (based on reported day-ahead prices) incurred to run the plant. The resulting market revenues generated were compared to a national cost of construction benchmark of $90/kW-year. This benchmark does not take into account cost differences between regions, which can vary from 10 percent to more than twice the benchmark cost.[127] Results are presented in Table 17.

Table 17: Investment not signaled in regions without organized markets.

Area	Net revenue from bilateral market ($/kW-year)
Southeast	-$69.5
Florida	-$41.3
Midwest	-$72.0
South Central	-$64.1
Southwest	-$30.5
Northwest	-$67.3

Note: Year ending June 30, 2003

Source: Platts *Megawatt Daily* and Platts *Gas Daily*. See footnote 126.

Consistent with high reserve margins and spark spreads across much of the country (see Appendix 2), the analysis results shown in Table 17 indicate that spot electricity revenues were insufficient to support profitable operation of a state-of-the-art combined-cycle plant and would not be sufficient to attract new baseload generation investment in the regions examined.[128] The analysis is based on a single bilateral price for a block of peak hours region-wide that does not reflect variations in costs throughout the day, locational characteristics, or congestion values. Thus, the price signals in these regions are limited. While there may be locations, such as the Atlanta, Las Vegas, and Phoenix metropolitan areas for example, within the regions where investment should be signaled, transparent locational price signals do not exist for these areas, preventing OMOI from conducting load pocket-specific analysis similar to those conducted for load pockets in regions with organized markets presented below. However, many of the same (and some different) impediments and incentives to new construction exist in these regions, some of which are summarized in Table 18.

Investment Opportunities in Load Pockets

Several locations around the country need additional resources. The need for resources is reflected in market prices through locational marginal prices, congestion charges and transmission line loading relief. Despite higher prices associated with these areas, limited investment in new

125 Standard & Poor's, Infrastructure Finance Criteria and Commentary, October 2000, as revised and updated at November 2003 in Project Finance Conference, New York City.

126 The bilateral electricity prices do not include capacity, ancillary and uplift payments as included in the first net revenue analysis. Though generators may also earn revenue for providing ancillary services to transmission operators in regions without organized markets, this revenue is not included in this analysis because no public data on this revenue stream are available for all regions. Analysis based on bilateral trade indices compiled by Gas Daily and Megawatt Daily during the assessment period. Debt service and equity targets are based on figures reported in Mind the Gap, by Richard Ashby and Art Holland of Pace Global Energy Services, published in Project Finance Magazine, July 2003. The targets are annualized, low-end figures of benchmark ranges for a two-unit, 500-MW combined-cycle plant operating 4,171 hours annually (on-peak, 5x16 year-round), with a 60-40 percent debt-to-equity split, 15 percent after-tax return and 8.25 percent interest on debt; the benchmark figures used in this report are not adjusted for possible regional differences.

127 Based on construction cost estimates developed for regions with organized markets as detailed in the note on Table 18 and footnote 124.

128 OMOI's oversight and analysis indicates that despite the economic competitiveness of new gas-fired generation, capacity factors remained low in the period despite their low heat rates indicating that new plants may not be running as much as they should in these markets based on purely economic dispatch (absent LMP or transmission congestion information). As a result, the profitability test may be overstating the run-time and revenues generated because it implicitly assumes economic dispatch.

generation, transmission or demand response was made in several locations:

- *New York City.* New York's installed generating capacity has barely maintained the desired 18 percent reserve margin over the past several years. Constrained localities within the state—New York City and Long Island—have been particularly vulnerable to capacity shortages and higher prices during high demand periods.
- *Areas in New England.* ISO-NE has excess capacity system-wide. Areas such as Maine have excess generation whereas load pockets such as Southwest Connecticut (SWCT) barely meet reserve requirements. The most heavily congested areas are SWCT, Northeast Massachusetts (NEMA)/Boston (where significant progress has been made), Southeast Massachusetts/Rhode Island and Vermont areas. Little of the region's new generation was located in these areas. Maine, on the other hand, benefited from large new generation additions but has insufficient transmission capacity to transmit its total output to load.
- *Areas in California.* While substantial new generation was added in California, little new generation was built in the congested areas of San Francisco, Los Angeles and San Diego and they continue to have generation deficits.
- *The Delmarva Peninsula.* While $58 million was invested in transmission upgrades on the Delmarva Peninsula between January 1998 and May 2003, congestion continued to occur in the region in some hours during the assessment period. The full effects of the investment were expected by PJM in the months subsequent to the assessment period.
- *Areas around Atlanta, Las Vegas, and Phoenix.* Transmission constraints occurred in these areas around growing metropolitan areas in regions without organized markets requiring operational procedures to maintain reliability, potentially preventing new generation from reaching load.[129]

With cost, site availability and ease of licensing and construction driving much of the generation site selection and insufficiently granular locational pricing signals and market price mitigation rules dampening incentives, much generation investment was made in locations of opportunity rather than greatest need, such as load pockets.

The results of net revenue tests for load pockets diverge from those done on a regional basis because generators received higher returns stemming from congestion costs in the areas but had higher expenses due to the higher costs of operation in the areas as well. Where higher returns outweighed higher costs, investment in the load pocket was signaled. The analysis attempts to account for differences in costs in the load pockets including the potential that siting is generally more difficult, environmental limitations more stringent and construction costs and operating costs are higher in load pockets. The accuracy of these estimates affects the outcomes of these net revenue tests.

Results are shown in the first row of Table 18. The test indicates building new generation in New York City and Long Island would be profitable based on assessment period prices, but that there was a low market valuation of building on the Delmarva Peninsula. The analysis also indicates that building in NEMA or SWCT would not be profitable. In New York City, the net revenue test used observed day-ahead prices that were frequently the result of bid mitigation, which sent a strong if incomplete signal that investment was needed. Given that roughly 50 percent of the unit-hour bids in the day-ahead market were mitigated in the assessment period, which sent a strong if incomplete signal that investment was needed but not financially incented, it is surprising that the net revenue test found that investment was strongly signaled in New York City in comparison to other load pockets. As new investment in New York City was needed but not occurring at a sufficiently high level, this inconsistent result may be due to inaccurate cost estimates, insufficient time for the price signal to be expressed in long-term investment, insufficient confidence in the sustainability of the prices, high construction risk or the existence of additional regulatory hurdles or mitigation regimes not reflected in the observed New York City prices.

In the case of the Delmarva Peninsula in PJM, where revenues are higher than for PJM as a whole, the net revenues test indicates investment would be slightly profitable. However, without location-specific estimates of the cost to construct and operate a new plant in an area with limited fuel supply options and constrained transmission facilities (indicating high costs for transmission upgrades by a new interconnection), the signal is a weak one. In New England the net revenue test indicates that investment would not be signaled for either SWCT or NEMA, but the signal may be explained partly by the fact that the 18-month net revenue analysis only includes locational pricing signals for four months, three of which are during the shoulder period. OMOI will continue to examine ISO-NE load pockets to determine if LMP, particularly in summer months, and the introduction of locational capacity prices provide stronger investment signals. PJM's analysis used calendar year 2002 data and cannot be directly compared to other regional analyses.

The decision to build new infrastructure in a load pocket is affected by several factors in addition to expected net revenue. Table 18 examines whether a set of factors are a relative incentive or impediment to investment in the

[129] SERC, 2003 Summer Assessment, May 2003. Second Biennial Transmission Assessment 2002-2011, Arizona Corporation Commission, Docket No. E-00000-D-02-0065, December 2002. Order, Public Utilities Commission of Nevada, Docket No. 02-11015 (www.puc.state.nv.us/ELECTRIC/dkt_02-11015/02-11015o.pdf) Oct. 15, 2003.

Table 18: Net revenue tests suggest investment in New York City, Long Island and Delmarva load pockets.

■ = Relative Incentive ● = Relative Impediment ◆ = Neutral	Load pockets in regions with organized markets					Load pockets in regions without organized markets		
	ISO-NE (SWCT)	ISO-NE (NEMA/Boston)	NYISO (Long Island)	NYISO (NYC)	PJM (Delmarva)	Southeast (Atlanta)	Southwest (Las Vegas)	Southwest (Phoenix)
Net revenue ($/kW-year) (1)	**-$15.7 (2)**	**-$20.0 (2)**	**$9.7**	**$82.6**	**$4.1**	**N/A (3)**	**N/A (3)**	**N/A (3)**
Siting and environmental permitting	● Limited site availability	● Limited site availability	■	● Limited site availability; high costs	● Limited site availability	◆	◆	◆
Ease of interconnection	■	■	■	■	■	◆	●	●
Transmission infrastructure	● System cannot support expansion or simultaneous operation of existing generation at full load	● Insufficient transfer capability within the Boston area and insufficient import capability	■ Physical constraints into Long Island	■ ● Physical constraints into (incentive) and within (impediment) NYC	■ Insufficient import capability	●	●	●
Transmission availability (short-term dispatch)	■	■	■	■	■	●	◆	◆
Fuel supply	◆	◆	◆	● Limited pipeline capacity	● Limited pipeline capacity	■	◆	◆
Locational energy pricing	■ Began March 2003	■ Began March 2003	■	■	■	● Not available	● Not available	● Not available
Locational capacity pricing	● Does not currently exist	● Does not currently exist	■	■	●	● Not available	● Not available	● Not available
Economic dispatch	■	■	■	■	■	●	●	●
Regulatory—market design risk	◆	◆	● Loss of Article X siting law	● Loss of Article X siting law	◆	●	◆	◆
Mitigation regime	● Reference prices may prevent recovery of fixed costs	● Reference prices may prevent recovery of fixed costs	■ Conduct and Impact & Alternate new gen reference price	■ ● Energy prices mitigation (impediment) Alternate new gen reference price (incentive)	● Uncertainty on applicability to new gen	Not applicable	Not applicable	Not applicable
Reserve margins	■	◆	■	■	■	●	■	■
Financing and financial strength of merchants	● Weak merchants	● Weak merchants	◆	◆	■	● Weak merchants	■	■

Note: Year ending June 30, 2003. Break-even operations would earn net revenue of zero. (1) Energy market revenues are based on an LMP or a zonal market-clearing price, reflecting higher costs in congested areas. ISO-NE provided the same costs of $115/kW-year for SWCT and for NEMA as for ISO-NE as a whole. PJM did not provide a separate revenue requirement for the Delmarva Peninsula. OMOI used the PJM-wide cost for the Delmarva Peninsula, which likely understates costs and overstates net revenues. NYISO provided a combustion turbine cost in NYC of $180/kW-year. Based on additional analysis, we adjusted the cost of a combined-cycle upwards to $225/kW-year due to higher capital costs, and applied this cost to both New York City and Long Island. It is likely that this overstates costs and understates net revenue on Long Island. Other assumptions mirror those used in regional net revenue analyses. (2) LMP was only in effect for four months during the assessment period, beginning March 1, 2003. (3) Not available as net revenues not measurable based on LMPs in these bilateral markets.

Source: Revenues supplied by ISO MMUs. Costs based on MMUs and FERC analysis.

identified load pockets. Mitigation is often applied in load pockets because of the greater potential for the exercise of market power in a constrained market. An unintended consequence of such mitigation can be the muting of investment signals through the suppression of prices. In depressing revenues, mitigation also diminishes returns on investments once made. Where signals to build in load pockets are communicated by price signals from organized markets, the signals may not have been acted upon in load pockets due to difficulty and timing of siting plants and obtaining environmental permits, high costs of construction, the financial weakness of merchant participants or uncertainty concerning changes in market structure and mitigation regimes. A generation owner's ability to re-power existing fossil and re-license existing nuclear plants also could negatively affect investment. In regions without organized markets, while transmission constraints may exist, investors may confront a lack of locational price signals that value these constraints and concerns about interconnection and economic dispatch.

Demand Response as an Investment Alternative

Demand response, an effective tool for dampening price spikes and protecting reliability, was largely missing from electricity markets during the assessment period. Lack of demand responsiveness to price harms competitive wholesale markets; however, demand response must offer the customer an attractive proposition. To assess whether a demand response action taken during the assessment period would have been cost-effective, OMOI analyzed the market return for a hypothetical customer willing to reduce demand. OMOI's analysis indicates that, given the relatively low energy prices during the assessment period, the hypothetical customer would have found low or no net benefits from the hypothetical demand reduction in most regions of the country if based on energy bill savings alone. Energy savings would have been sufficient to make demand reduction cost-effective for a demand responsive customer in New York City and nearly cost-effective in SWCT.

Customers in NYISO, PJM and ISO-NE have opportunities to participate in ISO or RTO demand reduction markets that provide incentives or guaranteed payments for demand reduction during emergency periods, and to receive revenues in addition to energy savings for providing products such as installed capacity and ancillary services. These additional revenues improve the cost-effectiveness of demand response in these locations if the customer is willing to assume the additional associated obligations and penalties for non-performance, if any. The effect of capacity and ancillary services payments on the overall cost-effectiveness of the hypothetical demand reduction is also assessed.

For purposes of this analysis, OMOI assumed a hypothetical large industrial/commercial customer who pays retail electricity rates tied to wholesale market prices.[130] We further assumed that the customer would reduce load by 1 MW whenever the market price exceeded \$50/MWh, and in return would avoid paying the energy prices prevailing during the hours of the reduction.[131] OMOI estimated that the customer would need to spend \$10,200 to be able to reduce load by installing interval meters and other enabling technology.[132] Based on the actual bidding through the NYISO and PJM demand response programs during the 18 months ending June 30, 2003, OMOI assumed that it would cost the customer \$50/MWh to run a back-up generator or take other action to effectuate the demand reduction.[133] In this hypothetical scenario, when the market price was \$50/MWh, the customer would have just covered the variable costs of demand reduction by avoiding energy payments. The customer would have had net revenues (energy savings less variable costs) when the market price was greater that \$50 and would have applied these savings to offset the \$10,200 investment.[134]

As shown in Figure 40, in Zone J (New York City) the customer would have fully recovered the fixed costs by early 2003, as indicated by the height of the blue area (cumulative revenues due to energy bill savings) crossing above and exceeding the break-even level represented by the yellow line.[135]

130 Large commercial and industrial customers in New York, New Jersey and parts of Maryland, Georgia and Texas pay retail rates tied to wholesale prices.

131 Energy is a large component of the all-in price of wholesale electricity in regions with ISO-operated markets. For example, see Figure 21. Outside of regions with ISO-operated markets, only energy prices are visible from market price indices. To allow comparisons across all electric regions, OMOI's analysis for this State of the Markets Report focused primarily on returns from energy, while indicating where other revenue streams are available and likely to affect the cost-effectiveness result.

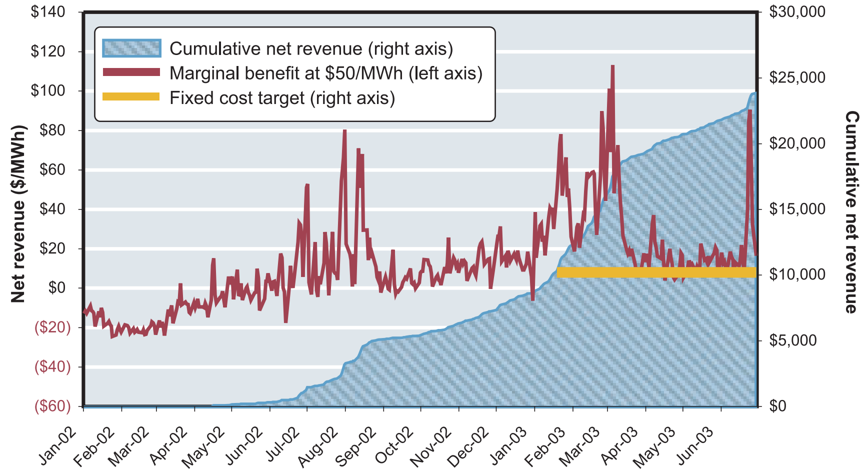
132 Assumption based on average cost incurred by participants in the NYISO demand response programs during 2002 who received NYSERDA matching funds for enabling technologies. Neenan Associates, Lawrence Berkeley National Laboratory, Pacific Northwest National Laboratory, How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance, January 2003.

133 Derived from ISO MMU responses to OMOI Data Request.

134 For the purposes of this analysis, a limiting assumption was made that the customer's core business operations allowed implementation of the demand reduction strategy in only 25 percent of the hours when the market price exceeded \$50. In addition, the customer would not implement the demand response action when the market price was less than \$50/MWh.

135 The marginal benefit line on Figure 40 shows the difference between the prevailing market energy price and the customer's assumed marginal cost of \$50/MWh. A negatively valued difference or marginal benefit, which prevailed from January through March 2002, indicates that the market price is less than the customer's variable cost and the customer would not have implemented demand reduction solely for the energy bill savings. Demand reduction in hours with a positive marginal benefit, which prevailed for most of the remainder of the assessment period, would have allowed the customer to fully offset variable costs and accumulate funds to pay for the \$10,200 investment in equipment (the fixed cost target). The cumulative revenue line on Figure 40 represents the accumulation of energy bill savings that could be applied to pay off the fixed costs.

Figure 40: New York City demand response is cost-effective.



Source: Based on price data from NYISO and Platts *Gas Daily*. Graphics and analysis by OMOI.

Table 19: Demand response cost effective in some key locations.

		Demand response would be cost effective with: Energy bill savings only	Demand response would be cost effective with: Additional capacity or ancillary payments
Regions with organized markets	**ISO-NE**		
	Mass Hub	Close	Yes
	SWCT	Close	Yes
	NYISO		
	Zone J (New York City)	Yes	Yes
	Zone A (West)	No	No
	Zone G (Hudson Valley)	Yes	Yes
	PJM		
	PJM Western Hub	No	Yes
	Delmarva	Close	Yes
	ERCOT		
	ERCOT	No	No
	CAISO		
	NP-15	No	No
	SP-15	No	No
Regions without organized markets	**Southeast**		
	Entergy	No	Not Available (1)
	TVA	No	Not Available (1)
	Southern	No	Not Available (1)
	Florida		
	Florida	No	Not Available (1)
	Midwest		
	MAPP	No	Not Available (1)
	Cinergy	No	Not Available (1)
	ComEd	No	Not Available (1)
	South Central		
	SPP	No	Not Available (1)
	Southwest		
	Palo Verde	No	Not Available (1)
	Northwest		
	Mid-Columbia	No	Not Available (1)
	COB	No	Not Available (1)

Note: (1) Mechanism not available for treating demand reduction as a capacity or ancillary services resource. The potential for the customer to avoid ancillary service charges under regulated tariffs is deferred for future analysis.

Source: OMOI.

Table 20: Merchant transmission projects.

Project	Capacity (MW)	Estimated cost	Original estimated in-service year
Harbor Cable (NJ, NY)	650	Unknown	2004
Lake Erie Link (Ontario, OH/PA)	975	Unknown	2004
Empire Connection (NY)	2,000	$750 million	2006
Chesapeake Transmission	400	Unknown	2007
Northern Lights (Alberta-U.S.)	2,000	$1.2 billion	2008
Pegasus* (Ontario, Quebec, NY, NJ)	3,000	$1.0 billion	N/A
Neptune (NJ, NY)	4,800	N/A	N/A
Northeast Utilities (CT, NY)	N/A	Unknown	Project abandoned

Note: *Not filed at FERC.

Source: FERC filings; press releases

Using these simplified assumptions, the analysis suggests that demand response would have been economic based on energy savings alone during the period in New York City and New York Zone G (Hudson Valley), and, as Table 19 indicates, would have been close in Southwest Connecticut and the Delmarva Peninsula in PJM. With additional revenues/savings from capacity or ancillary services, demand response would have been cost effective in each of these regions as well as in PJM and New England as a whole. Demand response based on energy savings alone would not have benefited the hypothetical customer elsewhere.

It is possible that a customer may not need to recover all of the fixed costs during the initial 18-month period as hypothesized here, and could spread recovery over a longer period of time. The lack of a publicly available forward price curve for all regions analyzed, such as would be provided by actively traded futures or forward contracts, prevents us from assessing whether the slower pace of fixed cost recovery prevalent in the remainder of the regions would be sufficient for a customer with a longer pay-back period requirement.

Transmission Investment

Investment in new transmission facilities was weak during the period, with some notable exceptions. While transmission costs represent an average 7 percent of total delivered energy costs to customers nationally, during the assessment period transmission did not receive a commensurate level of investment.[136] Transmission investment by either regulated or merchant players failed to keep pace with either generation or demand growth. While participants made large investments in power generation,[137] annual growth in generation capacity was 2 percent from 1998 to 2001, transmission investment in circuit miles grew less than 0.5 percent annually. This trend continued during the assessment period.

Of the transmission projects built in 2002 and 2003, most were built by regulated entities. After several years of licensing and siting efforts, some projects were approved during the assessment period, including a major project in Connecticut and several projects to relieve congestion in ERCOT. However, the number of approved projects is not as significant as those for gas transmission pipelines nationwide.

There were merchant transmission developments and independent transmission company formations during the assessment period. One merchant transmission project was built during the period, seven received FERC approval and two received partial development or full construction funding. The 330-MW Cross Sound Cable, a merchant direct current (DC) transmission line, was laid underwater between Connecticut and Long Island and financed based on the credit of a long-term contract with Long Island Power Authority (LIPA), which LIPA signed after winning a competitive auction. However, the project suffered considerable delay and political opposition to electrification and did not become operational during the assessment period. Partial funding was committed by private equity funds for another proposed merchant line between upstate New York and New York City (Conjunction LLC's 2,300-MW Empire Connection). In California, while only 15 miles of transmission were built during the assessment period, a public-private partnership raised equity and debt financing to upgrade the Path 15 bottleneck in central California and two projects were initiated near San Diego.

Based in part on the need for clear incentives for transmission investment, FERC provided return on equity and

[136] EIA Annual Energy Outlook, 2003.

[137] NERC 2002 Electric Supply & Demand Database, Edison Electric Institute, Cambridge Energy Research Associates, Beware Transmission Data, June 2003. Includes preliminary data for transmission for 2001, and 2002 for new generation capacity.

structural incentives for the creation of independent transmission. Two integrated utilities in Michigan, DTE Energy and Consumers,[138] sold their transmission assets to create such entities and one in Wisconsin, American Transmission Co., while not independently owned, is now operated as a stand-alone transmission company. While there has been limited independent operating history for these companies, each has increased proposals and expenditures for new projects, both within and outside their regulated footprints.

Structural and financial impediments explain much of the relatively low investment level. It remains easier and quicker to site, license and construct new power plants and gas transmission pipelines than electric transmission lines. The primary factor making siting gas transmission pipelines easier than siting electric lines is regulatory bifurcation. In order to commit funds for transmission investment, developers generally require confidence regarding cost recovery, either through regulated regimes or in the merchant context through sustained price signals, visibility of revenues and costs, reasonable certainty of project completion based on obtaining rights-of-way, environmental and regulatory approvals and the ability to obtain equity and debt financing.

Clear market price signals for new transmission do not exist in regions lacking LMP. In markets with LMP, price signals are insufficiently long term. While TLRs are responses to congestion and may signal repeated congestion at identified flowgates in regions without organized markets, curtailments are not ranked on economic merit, thus providing no price signals or revenue sources for new transmission investment. In organized markets, LMP signals exist and can be captured financially through FTRs. However, LMPs vary over time and are difficult to lock in as a long-term revenue source.[139]

During the assessment period, market participants had limited tools to forecast projected transmission revenues. For merchant facilities, available instruments did not provide long-term revenue certainty. TLRs are not financial instruments and FTRs were available only as seasonal or annual instruments and would need to be longer term to support financing. For the regulated additions that represent the majority of transmission investment, revenue certainty is assured only after siting, licensing and regulatory approvals. Siting difficulties caused by environmental and community concerns are compounded by the multiple jurisdictions through which transmission lines often pass. While there is federal siting authority for natural gas pipelines, the lack of such authority for electric transmission has compounded difficulties in coordination and obtaining approvals from multiple jurisdictions. Measuring benefits and allocating costs between beneficiaries and end-use customers that vary over time presented difficulties for merchant and regulated projects alike. For the integrated utilities, which own the majority of the transmission system, new lines were added to the rate base and are paid for by end-use customers in the service territory where the lines were built. Mechanisms to better align benefits and costs so that regional generation and load outside of the service territory pay for benefits of congestion relief and reliability are being addressed by regional planning processes such as ISO-NE's Regional Transmission Expansion Process.

Incumbent utilities with the financial ability to invest must allocate capital to transmission projects, but can have powerful disincentives to doing so. Because of regulatory lag on existing rate base, a utility can increase earnings by spending less on operations and maintenance than provided for in their tariffs which are based on historical cost-of-service. In the absence of mandatory reliability standards, there may be little prospect for financial penalty to the utility for any adverse reliability effects of the lower spending. During the assessment period, utility management found more compelling uses for capital, based on higher return expectations (as was the case for generation when investment decisions that affected expenditures in the assessment period were made), though as generation returns have not met expectations, this is changing. Incentives exist for integrated companies not to invest in transmission that will relieve congestion to load pockets where they also own generation. In addition, in regions with partial or initial RTO and ISO formation, uncertainty over ultimate control and ownership made investment less attractive.

Transmission investments are long-lived and the lack of adequate and sustained energy price signals that can be contracted upon, made more difficult by declining liquidity in forward markets for power, increased the difficulty of making merchant investment decisions and financing plans once made. If built outside of the rate base, transmission lines generate cash flows based on market price differentials for energy at both ends and these cash flows are more difficult to project than those for generation. Difficulties raising debt financing for market-based transmission projects may have been compounded by financial markets tarring merchant transmission lines with the brush of merchant generation.

[138] Docket Nos. ER02-23-000 and EC03-95-000.

[139] New transmission construction is particularly susceptible to diminishing its own value by relieving the very congestion that led to the price differences it arbitrages. While an issue confronted by other capital investment with scale economies, it is particularly acute for transmission in part because of the relative size of the market it addresses and because participants have found it difficult to capture the arbitrage value suggested by LMP up front by entering contracts before building.

General Investment Conditions

In general, the financial conditions of market participants impeded the ability and willingness to initiate significant levels of new infrastructure investments during the assessment period. While significant levels of new investment in generation did occur during the assessment period, it had been planned and financed during the boom preceding the period when signals and capital were present. Ten of the most active of these companies, which include energy merchants and convergence companies, spent $28.5 billion to finance construction of 60 GW, or roughly 42 percent of new capacity installed from 1998 through 2002, and were rewarded with growing equity markets until the market dropped in 2001.[140] In contrast to periods before deregulation of wholesale power markets, investors and lenders and not end-use customers bore a significant portion of underperforming investments made in deregulated generation assets.

Merchants, convergence companies and traditional utilities borrowed heavily to fund investments in new generation, as well as fund acquisition of existing generation and establish power marketing and trading arms, increasing reliance on debt as a portion of their capital structures. Total debt for the 40 largest power and utility companies,[141] which had been below $150 billion from the 1980s through the end of 1996, rose to $200 billion by the end of 1998 and peaked at above $367 billion in March 2002. Overall debt levels remained at roughly $350 billion in 2002 and 2003, but debt composition changed with continued borrowing by certain participants, debt retirement by others, negotiated maturity extensions and debt defaults. Debt to total capital rose from 54 percent for the 40 largest companies at the end of 1996, to a high of 67 percent at the end of 2001 and remained at approximately 66 percent through June 30, 2003 (figures that would be higher if they reflected off-balance sheet financings for project financed projects).

The large infusion of new generation in many regional markets contributed to low and declining energy prices during the review period. At the same time, generators were squeezed by the increasing costs of natural gas. Prices both signaled less need for new investments and lowered the financial ability for some participants to fund that infrastructure. In the organized markets where capacity markets existed, excess capacity decreased prices. As a significant proportion of new generation was gas fired, lower spark spreads hurt operating margins for many merchants, lowering equity returns and/or threatening debt service. In some regions, bid mitigation negatively affected earnings.

Low operating revenues coupled with heavy debt burden incurred to finance construction and acquisitions threatened the financial condition of most merchant and convergence companies, leading to credit deterioration, project cancellations, exits or cutbacks from trading and marketing by some, and the bankruptcies of others. In general, regulated utilities without large affiliated merchant activities still retained relatively strong finances and remained able to make additional investments. As shown in Figure 41, credit deterioration was marked in the assessment period, continuing the trend established in 2001. At the beginning of 2002, of the 313 utility holding companies and operating subsidiaries rated by Standard & Poor's, 49 percent were rated A or better, 45 percent in the BBB category and 6 percent below investment grade. By year end, 3 percent were rated A or better, 46 percent were BBB rated and 8 percent were non-investment grade (BB+ and lower). During the period, 182 ratings were downgraded, while 15 were upgraded. In the first half of 2003 the trend continued, though its pace slowed somewhat as 83 ratings were downgraded and 8 upgraded. Non-investment grade companies were downgraded to even more speculative grades.[142] Merchants and utility holding companies with significant exposure to merchant activities experienced the largest credit deterioration and it affected their business operations most significantly.

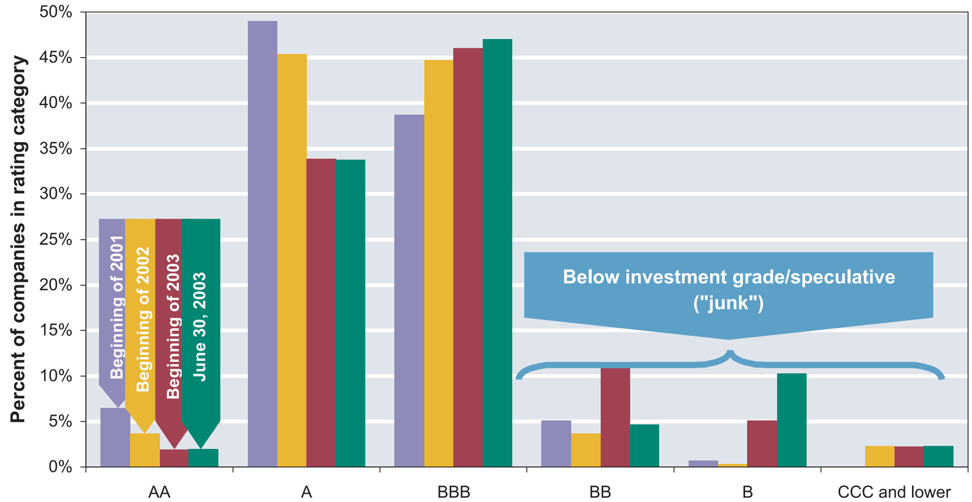
Utility divestiture of generation, ISO and RTO formation and enhanced competition progressed to a greater degree in certain regions of the country than in others, with more generation sold or transferred in the ISO-NE, NYISO, Midwest, ERCOT and CAISO than in the Southeast, the Southwest and the Northwest. Partially because of the plight of the merchant generators and traders, deteriorated credit and equity conditions were more prevalent in regions with operating or forming regional markets. The market structures in the regions without organized markets did not experience that level of restructuring. A large majority of the investment made in these regions was by federal or municipal entities or integrated utilities operating under regulated, cost-based models without prevalent credit and equity issues. However, in certain regions, there was an attempt by unregulated players to make inroads and in the Southwest region, Entergy and Southern subregions of the Southeast, and to a lesser extent in the Northwest, significant generation was built by merchants (much of which did not perform to

140 Deutsche Bank Securities, Factset: Includes AES, Aquila, Calpine, Dynegy, El Paso, Edison Mission Energy, Mirant, NRG, Reliant Resources and Williams. The market capitalization of these 10 companies grew from $49.4 billion at year-end 1998 to $172.3 billion at year-end 2000.

141 Factset: Includes Ameren, AEP, AES, Aquila, Allegheny Energy, Constellation, Cinergy, CMS Energy, Calpine, Dominion Resources, DPL, DTE Energy, Duke Energy, Energy East, Enron, Entergy Corp., ComEd, Edison International, Exelon, FirstEnergy, FPL Energy, GPU, Mirant, Niagara Mohawk, NRG Energy, Northeast Utilities, Orion Power, PG&E Corp., PSE&G Corp., Progress Energy, Pinnacle West, PPL, Centerpoint Energy, Reliant Resources, Scana, Southern Co., TECO Energy, TXU Energy, Wisconsin Energy and Xcel.

142 Standard & Poor's, Utilities and Perspectives, June 26, 2003, and previous. Includes utilities with both electric and gas operations.

Figure 41: Energy company credit ratings deteriorate before and during the assessment period.



Source: based on Standard & Poor's data from Bloomberg L.P. Graphic and analysis by OMOI.

expectations). In regions with organized markets, the lowest ownership of capacity by non-investment grade companies was 22 percent in PJM and the highest was in ERCOT, with 48 percent. Of the regions without organized markets, by contrast, only in the AZ-NM-SNV subregion of the Southwest was more than 10 percent of the capacity owned or energy produced by non-investment grade entities.[143]

From January 2002 until June 2003, merchant and convergence (companies with operations spanning power and gas trading, marketing, transmission and generation) sector market capitalization declined from $77.4 billion to $19.0 billion and two merchants, NRG Energy and National Energy Group, declared bankruptcy. Enron was already operating under bankruptcy. Other merchant and convergence companies restructured their balance sheets, attempted to sell assets, cancelled announced projects, cut back or exited energy trading and sought new sources of capital. Increased risk perceptions by investors in the sector and increased segmentation of the risks of particular participants led to increased capital costs for many. Amid declining credit ratings and stock prices, companies sought to raise cash needed to finish construction of partially completed plants, support remaining trading activities and extend or repay debt maturities. Where possible, participants provided collateral in performing assets to obtain new loans or extensions. Regulated utilities outperformed the merchant sector in equity markets in regions both with and without organized markets.

New sources of capital emerged and the sector attempted to limit the need for new capital. While traditional retail and institutional equity and fixed-income investors lost or took money out of the sector, high yield fund investors, private equity funds and hedge funds emerged as new sources of capital. The sector also attempted to limit the need for new access to capital by selling assets, restructuring or turning over assets to lenders. Lenders in many cases showed a willingness to extend maturities or not enforce lending covenants for troubled plants and waited for improved market conditions. Sales of underperforming assets to new entrants and stronger players occurred less often than many expected. More prevalent were sales of performing assets by troubled merchant corporations to provide liquidity and pay down debt.[144] The paucity of deals for troubled assets was due partly to divergent price expectations of buyers and sellers and because sellers sought to sell assets without long-term contracts while buyers desired contracts. The large number of plants for sale gave those who valued new capacity the option to purchase rather than build that capacity, which was in most cases a quicker and cheaper option.

Lower credit ratings had implications not only for capital costs but also for the liquidity and collateral requirements for trading and marketing in the futures and physical power and gas markets. Heightened collateral requirements and changes in how rating agencies assess the risk of power trading led to higher explicit or implicit equity support needs for these activities. This ultimately resulted in reduced electricity and natural gas trading and the exit

143 Standard & Poor's, Utilities and Perspectives, June 26, 2003 and previous. Platts POWERdat, August 2003.

144 Citigroup Smith Barney, Ray Niles, May 8, 2003. From Jan. 1, 2002 through May 1, 2003, 7,200 MW were sold for $3.5 billion in 17 transactions

of several participants.[145] While liquidity declined, financial players, including investment and commercial banks and hedge funds, entered, returned to or strengthened trading activities to take advantage of the void left by the exit of many participants.

Summary of Electricity Market Performance

Based on the analysis detailed above, we conclude that electric markets performed with varying success, but with greater effectiveness and transparency in those regions with markets operated by ISOs or RTOs. Progress was made during the assessment period in market design and market operation. Nevertheless, there remained regions of the country where the basic conditions and market structure to support efficient market performance were not in place. OMOI will continue to monitor progress in the future on issues of associated market development, risk management, transparency and access by independent generators to regions without organized markets.

[145] Standard & Poor's, *Standard & Poor's Introduces New Price Assumptions for Merchant Power Exposure*, Oct. 30, 2003. Companies announcing scaling back or exiting from power trading in press releases from November 2002 though March 2003 included: Allegheny Energy, Ameren Corp., AEP, Aquila, Calpine, CenterPoint Energy, Cleco, CMS Services Marketing & Trading, Duke Energy, Dynegy Marketing and Trade, El Paso Merchant Energy, Enron, E Prime, IdaCorp, Mirant, National Energy Group, NRG Energy, Reliant Resources, Tractebel North America, UBS Warburg Energy and Williams.

Natural Gas Market Performance

The North American natural gas market is an integrated system of regional markets of production and consumption, connected by an extensive pipeline network and related infrastructure. Physical and financial transactions involve multiple venues, pricing methods, delivery periods and delivery points.

Reported natural gas prices during the assessment period generally behaved consistently with the forces of supply and demand. The market response exhibited characteristics of a well functioning market—it delivered products on time to customers and spurred reasonable levels of investment. Moreover, participants had multiple alternatives for managing risks, including price volatility.

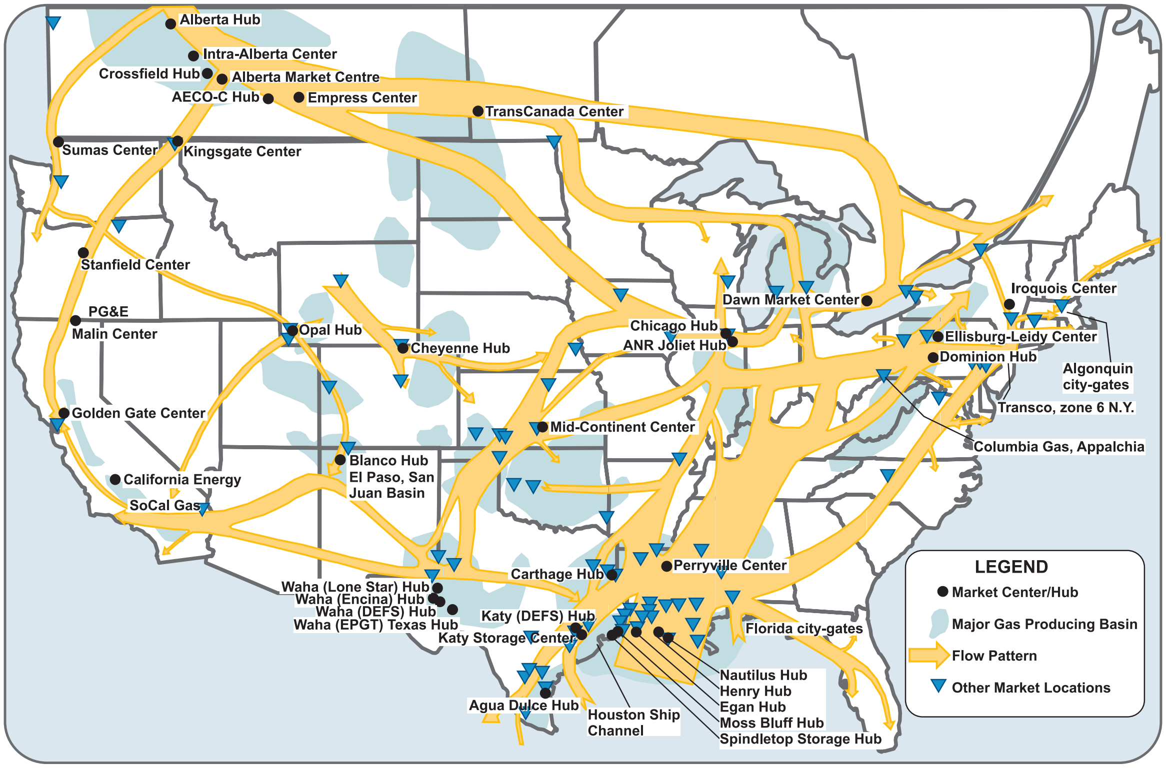
During the assessment period, the market did face challenges. Over the past two years, the natural gas market exhibited increases in prices, greater price volatility, supply tightness, severe swings in storage inventory volumes, credit problems, decreasing volumes of trade and price index credibility issues, among other factors. Market participants had opportunities to use storage and physical, financial and pipeline capacity contracts to manage risks, but liquidity for forward contracts declined. The exit of several major energy merchant companies, the decrease in the activity level of other companies and credit concerns reduced the liquidity for forward contracts. The ability of participants to hedge risks was limited by the decline in liquidity (as evidenced by the number of trades offered to the market) and the creditworthiness of the counterparties. This is important for end-users of natural gas because it influences their ability to manage price volatility effectively.

Because of variations in the types and locations of natural gas transactions, the quality of information about the formation of prices varied. The Henry Hub in Louisiana remained a highly liquid physical market and was the benchmark for many derivative financial products; it was the most transparent point for price formation during the assessment period. In markets that offer limited transparency to market participants and those not involved in transactions, price discovery was frequently based on commercially developed indices assembled through surveys of market participants who agree to report and indices developed on the basis of exchange-conducted transactions. During the assessment period, the adequacy and reliability of price information became an ongoing concern that both the Commission and industry are addressing.

This section explores five aspects of natural gas market performance. They include:

- Market Structure
- Prices and Locational Basis
- Risk Management
- Transparency
- Investment

Figure 42: Regional North American natural gas markets are connected by pipeline and related infrastructure.



Note: "DEFS" is Duke Energy Field Services Co. "EPGT" is EPGT Texas Pipeline Co.

Source: EIA, GasTran Gas Transportation Information System, Natural Gas Market Hubs Database, as of August 2003.

Market Structure

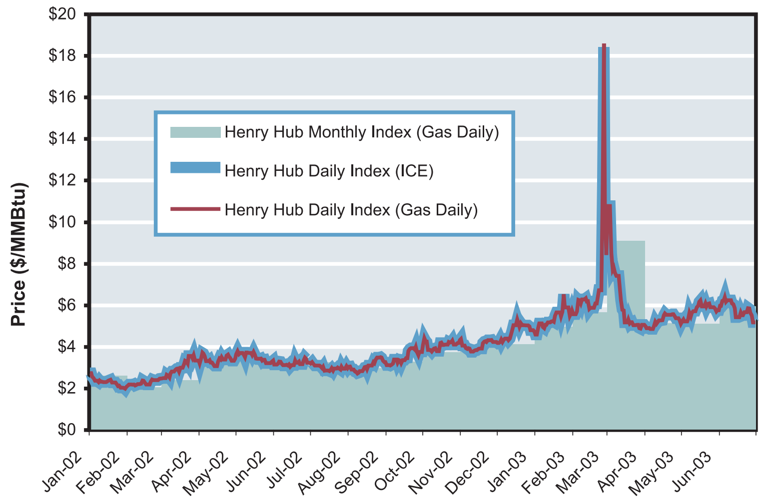
Critical physical characteristics of natural gas determine in large part the structure of the natural gas market. The first is that natural gas is found in geologic basins, which are concentrated in selected locations in the United States and the world. Second, natural gas producing basins are typically far from consuming centers. Finally, natural gas must be enclosed in a vessel, typically a pipeline, to be shipped. The result is that, when used as a fuel, natural gas requires a complex and relatively inflexible infrastructure to gather the gas from the production fields and deliver it to customers. The physical characteristics of natural gas and the requirements that they impose on the supply system drive the structure of the market, as is illustrated in Figure 42.

Upstream, natural gas production is a competitive industry. More than 6,800 companies, including 21 large integrated firms, produce natural gas in the United States. In addition, imports from Canada provide approximately 17 percent of U.S. consumption, and liquefied natural gas (LNG), imported from offshore sources, provides less than 1 percent of the nation's natural gas supplies.

Natural gas typically travels from the production site through gathering pipes to processing facilities. With some exceptions these facilities are competitive and not regulated. Shippers (or their agents) can purchase gas at either upstream receipt points or downstream delivery points (often a market center or hub). A hub or market center can provide customers with access to two or more pipeline systems, transportation between these points, metering and administrative services to facilitate the associated transactions and in some cases storage, balancing, parking and loaning of gas. The most important hub in the United States is the Henry Hub, located at Henry, Louisiana. Henry Hub connects 14 gas pipeline systems, is a successful cash trading marketplace and is the delivery point for the Nymex natural gas futures contract.

From the upstream facilities, most natural gas moves to customers on the interstate pipeline system, a system of over 180,000 miles of large diameter, high-pressure pipelines. Because of economies of scale and scope and barriers to entry, interstate natural gas pipelines are natural monopolies, regulated by the Commission. Pipelines operate as contract carriers, offering a variety of

Figure 43: Monthly natural gas prices peak in late-winter 2002 and remain high through following summer.



Note: For the assessment period, *Gas Daily* and ICE next-day physical prices at Henry Hub averaged within $0.01/MMBtu of each other.

Source: Platts *Gas Daily* and ICE. Analysis and graphic by OMOI.

firm and interruptible transportation services, storage and gas custody management services.

As the gas moves between producing and consuming centers, it is often placed in storage. Storage fills the gap created by seasonal variations in gas demand. In winter, demand exceeds the amount of gas coming out of the ground, and in summer, production exceeds demand. As of the end of 2002, working gas storage capacity in the U.S. lower-48 states was estimated at 3.3–4.0 Tcf.[146] Regionally, approximately one-quarter of storage capacity is located in producing regions and three-quarters is located in consuming regions.[147]

The integrated physical infrastructure provides a flexible system, enabling customers to buy natural gas from numerous producers, marketers and local distribution companies (LDCs). For example, customers can acquire natural gas upstream or deliveries at downstream locations and rely upon natural gas marketers to purchase, contract for transportation and storage, deliver and handle the financing of their gas. Wholesale marketers manage supply chain activities on behalf of their customers using their knowledge of regional markets, physical or financial markets, enhancement of the value of physical assets or price and credit risk. The typical gas customer—especially the residential customer—has gas delivered by one of the 1,294 LDCs in the United States,[148] which take title to the natural gas when it enters the pipeline, transport it to their own distribution systems, and resell it to customers. The LDCs, with some exceptions, are typically the "retail" marketers.

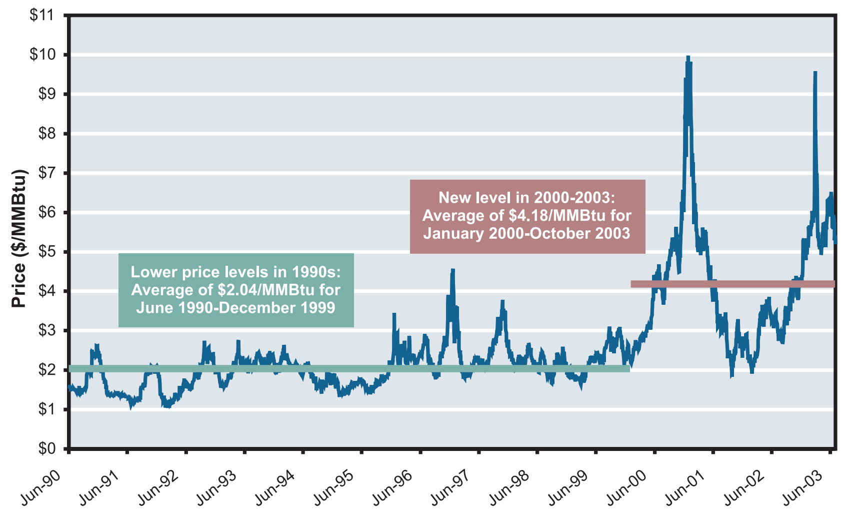
Regulation of the natural gas supply chain seeks to allow competitive forces to prevail where they exist and to affect only those portions of the system where participants have the potential to wield market power. The Commission does not regulate the market price of natural gas commodity bought or sold along a pipeline. The Commission does regulate the interstate pipelines with the objective of assuring that customers have access to competitive gas supply opportunities. Commission regulations establish open access conditions and maximum tariffs for transportation. Most gas storage facilities are owned by pipeline companies or LDCs and therefore are regulated, either by the Commission or by the states. States also regulate (as appropriate) gathering, intrastate pipelines and natural gas sales by LDCs to end-use customers.

[146] EIA, "Natural Gas Storage," presented by William Trapmann at North American Gas Strategies Conference, Oct. 29, 2002. Storage capacity estimates vary due to assumptions, methodology and survey organization, among other factors.

[147] EIA spreadsheet, U.S. Total Natural Gas Storage Capacity by State, last updated on 7/22/03. Data are through 2001. Excel file name: ng_stor_cap_sac_a_s.xls. Regional working gas storage capacity estimates are based on state ratios of total gas storage capacity.

[148] American Gas Association, www.aga.org, Stats & Studies, State Profiles.

Figure 44: Natural gas futures prices reach new levels.



Source: Nymex data from Bloomberg L.P. Analysis and graphic by OMOI.

Prices and Locational Basis

Prices

Natural gas prices reached new levels in the assessment period. As shown in Figure 43, prices were relatively low in early 2002 but began rising in spring 2002 and escalated rapidly in early-2003 as the weather turned more severe, and increased consumption stressed the natural gas supply chain.

From the start of January 2002 through mid-January 2003, the daily Henry Hub price increased over 100 percent, or $3/MMBtu. By late-February, 2003 daily citygate prices spiked as high as $40/MMBtu in New York, reflecting severe weather and well freeze-offs.[149] At Henry Hub, February 2003 prices spiked to near $19/MMBtu. After a decline in Henry Hub prices through March and early April 2003 to $4.86/MMBtu, prices rose again to $6.26/MMBtu in early June 2003. Prices ended the assessment period at $5.18/MMBtu.

The significance of the upturn in natural gas prices was reflected in the new peaks in both spot and forward market prices for Henry Hub and forward indices. Forward markets exhibited a significant upward shift in average price as compared to the 1990s, as shown in Figure 44. From June 1990 through December 1999, the average price for next month futures was $2.04/MMBtu. From January 2000 through October 2003, the average next-month futures price more than doubled, to $4.18/MMBtu.

Consumption

Customers responded to the higher prices as appropriate in an efficient market. Estimates indicate consumption of natural gas for the first half of 2003 was lower than in the first half of 2002. Two sectors, industrial and power generation, reduced natural gas use in the wake of higher prices, while residential customers and commercial facilities increased their consumption largely in response to colder weather, as shown in Figure 45.

The most significant change was in power generation. Monthly generation trends for electric power producers by source are highlighted in Appendix 5. After increasing 6.2 percent between 2001 and 2002, natural gas use in power generation declined 13.0 percent in the first six months of 2003 relative to the same period in 2002. Key factors accounting for the decline include:

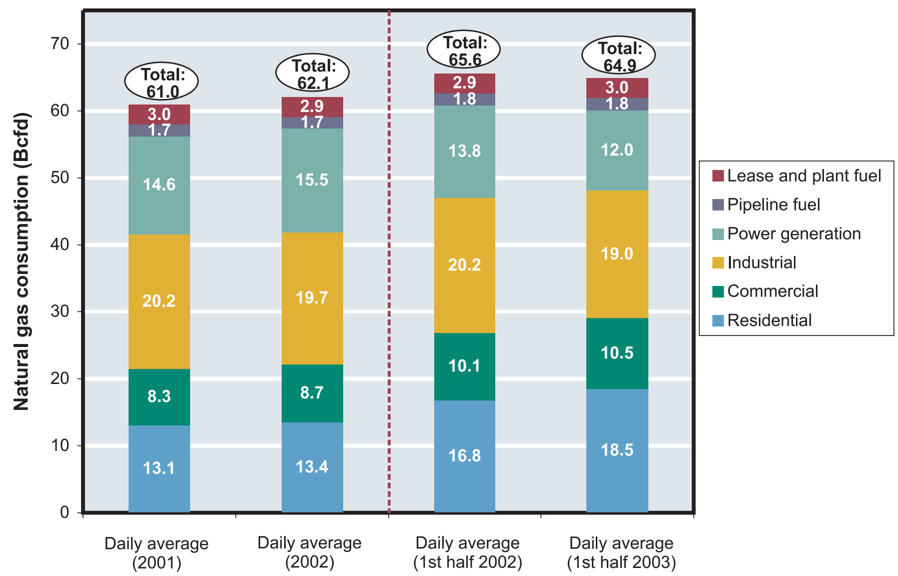
- fuel switching from natural gas to oil,
- improved hydroelectric availability in the West, and
- replacement of less efficient natural gas units with gas combined-cycle plants that can generate the same amount of electricity with about 30 percent less fuel.[150]

Industrial users continued to reduce their natural gas use, which fell from 20.2 Bcfd to 19.7 Bcfd (2.2 percent between

[149] FERC Staff, Report on the Natural Gas Price Spike of February 2003, presented to the Commission on July 23, 2003.

[150] The heat rate on a state-of-the-art gas combined-cycle plant is usually 7,000 Btu/kWh or lower, whereas older steam gas plants may have heat rates in excess of 10,000 Btu/kWh.

Figure 45: Overall consumption declines in first half of 2003, but residential and commercial demand increases.



Note: Natural gas consumption by vehicles represents less than 1 percent and is not shown.

Source: EIA data compiled from EIA forms 759, 857 and 895. Analysis and graphic by OMOI.

2001 and 2002). Industrial sector gas consumption declined another 5.6 percent in the first half of 2003 relative to the same period in 2002. Since 2000, industrial production levels represented by a composite index of six key energy-intensive industries accounting for as much as 70 percent of overall industrial gas demand—food; petroleum; paper products; stone, clay and glass; chemicals and primary metals—have declined by over 6 percent.[151] Some energy-intensive industries have retrenched more than others. Increases in natural gas prices have had pronounced influence on the commercial operations of the chemical and aluminum industries. During the assessment period, eight U.S. manufacturers of nitrogen fertilizer closed their plants permanently.[152] Numerous aluminum facilities are currently idled, and the United States may have become the marginal supplier of aluminum production internationally.[153] Many U.S. chemical manufacturers now have a comparative cost disadvantage because foreign feedstock (naphtha) prices are lower.[154]

The commercial and residential sectors demonstrated substantial increases in consumption over the assessment period, indicating the effect of severe winter weather in 2003. Despite a warm winter, residential customers increased natural gas consumption 2.8 percent from 2001 to 2002; in the much colder first half of 2003, residential natural gas consumption soared, rising more than 10 percent relative to the first half of 2002. Commercial customers also demonstrated strong demand for natural gas, with a 4.2 percent increase in consumption in 2002 relative to 2001 and an increase of 4.6 percent in the first half of 2003 relative to the earlier year.[155]

Supply

Tight supplies were a major factor in the increase in natural gas prices. According to the EIA, domestic production fell 3.2 percent in 2002, which was consistent with a 26 percent drop in the rig count during the same period.[156] For 2003, EIA estimates that production increased, but other analysts disagree, arguing that production fell.[157] Resolution of these divergent estimates is not possible at

[151] Energy Ventures Analysis, Inc., Outlook for Natural Gas Demand for Winter 2003–2004.

[152] General Accounting Office, Natural Gas: Domestic Nitrogen Fertilizer Production Depends on Natural Gas Availability and Price, GAO-03-1148. September 2003.

[153] Nearly 200 MMcfd of Pacific Northwest gas demand related to aluminum smelting may be permanently lost. CERA, “The Demand Wild Card: Pacific Northwest Aluminum,” July 2003.

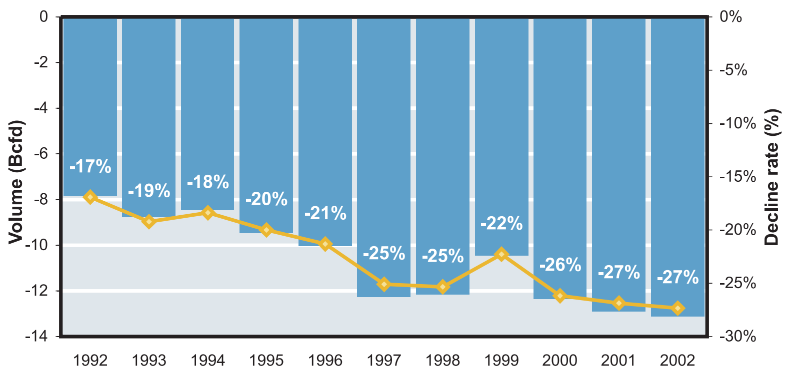
[154] The Federal Reserve Board, The Beige Book, Oct. 15, 2003.

[155] OMOI analysis of EIA data compiled from forms 759, 857 and 895; available through EIA's Natural Gas Navigator, http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_nus_m_d.htm.

[156] EIA data, available through EIA's Natural Gas Navigator, Natural Gas Marketed Production, http://tonto.eia.doe.gov/dnav/ng ng_enp_sum_vgm_a_s.xls. (last updated on 7/22/03); and Baker Hughes, Inc. natural gas rig data, website: www.bakerhughes.com, spreadsheet: U.S. Rotary Rig Count.

[157] Lehman Brothers Equity Research, U.S. Energy and Power, Oil & Gas: E&P (Large Cap) Industry Update, Oct. 31, 2003. Thomas R. Driscoll is the analyst.

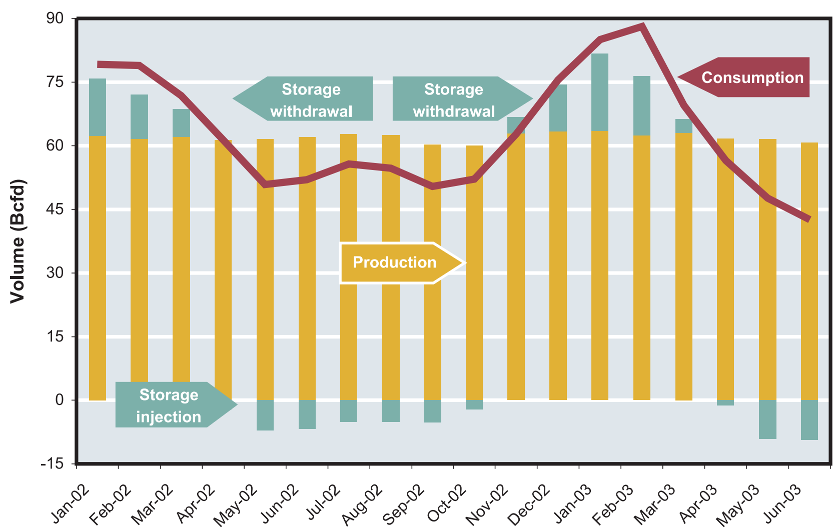
Figure 46: Decline rates increase.



Note: Decline rate of base gas production if no new wells had been drilled, and equivalent production loss.

Source: NPC, *Balancing Natural Gas Policy*, September 2003.

Figure 47: Production versus storage withdrawal gap widens in February 2003.



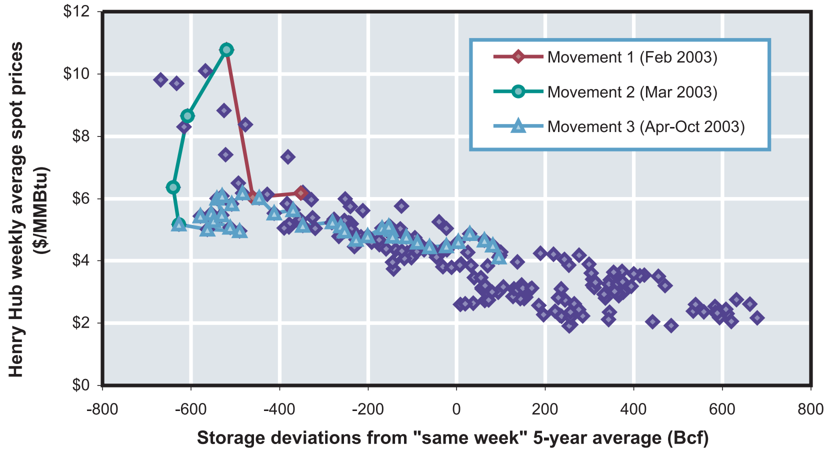
Source: EIA consumption, storage, supply and import/export data from EIA; some supply data provided to EIA by the U.S. Mineral Management Service; import/export data from DOE's "Quarterly Natural Gas Import and Export Sales and Price Report." Analysis and graphic by OMOI.

this time. If an increase occurred, it did not overcome the loss of deliverability in 2002, relative to 2001, with the resulting effect that markets are tight. Other supply stresses during this period included reduced Canadian imports and increased exports to Mexico.

As gas prices increased in 2002, producers responded with additional drilling in an appropriate response to price signals. Nevertheless, drilling did not immediately relieve supply tightness, because of the time required to bring new gas production and discoveries to market and also the accelerating decline rate for existing production, as illustrated in Figure 46.

Figure 47 illustrates how tight supplies, combined with strong winter demand, resulted in a gap that put upward pressure on prices. The gap appears to be larger in February 2003, the month when a natural gas price spike occurred, than it was in February 2002 or any other time in the assessment period. Generally the supplies that fill this gap include a variety of LDC peak shaving resources, pipeline and utility linepack options that are not measured in the available statistics. Other explanations include inaccuracies in documenting volumes moving in and out of storage and lags and mismatches in time periods among data sources.

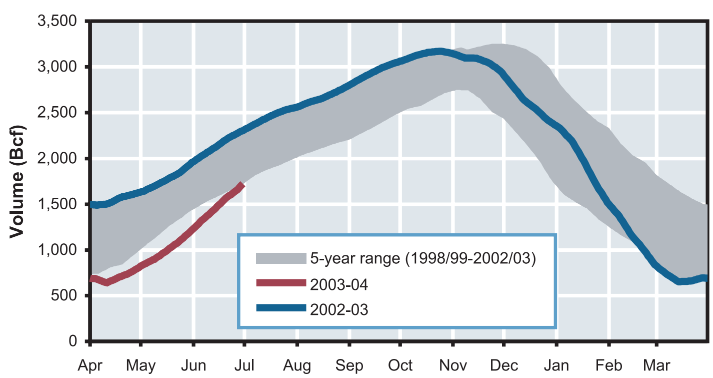
Figure 48: Relationship strong between storage level and price.



Note: Figure includes 199 data points, for the weeks ending 12/31/99–10/31/03.

Source: EIA. Weekly average of Platts *Gas Daily* spot price data. Analysis and graphic by OMOI.

Figure 49: Storage use pushes upper and lower capacity limits.



Source: EIA. Analysis and graphic by OMOI.

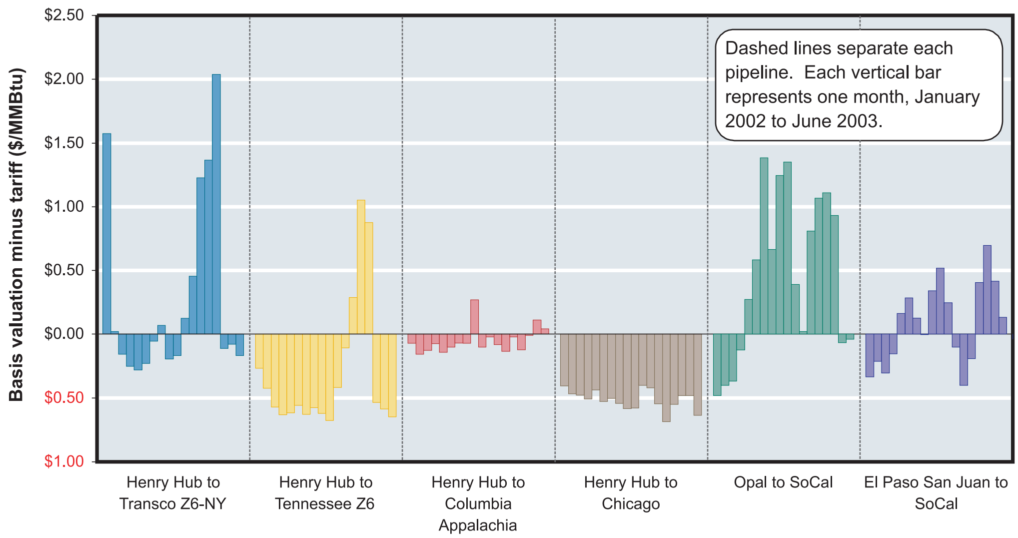
Storage

Tight storage conditions also influenced prices. Figure 48 shows that lower-than-average storage levels are associated with higher prices.

As shown in Figure 49, over the 18-month assessment period, storage conditions shifted from abundant, reaching five-year highs and the upper levels of capacity in April 2002, to tight, reaching five-year lows in April 2003. The April 2002 storage levels were the result of a warmer-than-normal winter during 2001–2002 that reduced natural gas use. Robust injections through the summer and fall translated into five-year high storage levels at by the beginning of the heating season on Nov. 1, 2002. However, an unusual cold snap in late-November and early-December prompted above-average storage withdrawals early in the season. Continuing cold weather in January and February severely reduced working natural gas storage levels. As a result, working natural gas in storage began the 2003 injection season at a five-year low level of 623 Bcf, or 15 percent below the prior low in terms of total supply. As the fill season continued, weekly injections often set records, despite the higher costs of natural gas to fill storage.

From February into summer 2003, uncertainties about whether storage could recover from the steep drawdown helped to support higher natural gas prices. Faced with record low storage levels and the potential for increased natural gas use for power generation if the summer were unseasonably warm, storage users continued to buy and inject gas into storage, despite the record prices.

Figure 50: Pipeline capacity generally adequate for much of the year.



Source: Platts *Gas Daily*, Pipeline Tariffs. Analysis and graphic by OMOI.

Locational Basis

Regional price differences, signals that additional pipeline capacity may be needed when they exceed tariffs by a sufficient amount and for a sufficient amount of time, have been moderate in most regions. For this report, we will refer to the difference between a natural gas price at a market hub, citygate or supply receipt area and a reference point, most often Henry Hub, as "basis" or "locational basis differential."[158]

During periods of low pipeline capacity utilization, the basis differential will reflect the variable costs of transportation and typically be below the 100 percent load factor pipeline tariff rate in an efficient natural gas market. As capacity tightens, the basis differential will reflect regional supply and demand conditions in a market and, depending on the severity of the constraint, the basis may exceed the cost-based tariff rate for transmission capacity. Consistently and sufficiently high basis differentials signal continued constraints and the need for new pipeline capacity.

Functionally meaningful basis relationships are consistent with physical gas flows. For example, there is a key relationship between gas sold or bought in Zone 3 (Station 65) on Transcontinental Gas Pipe Line (Transco) and deliveries into New York City from Transco Zone 6. Because the basis between the two reflects the market's view of the difference in value of natural gas between the two points, a price increase in Zone 3 of 15 cents typically leads to a price increase of equal or greater value at Transco Zone 6-NY. During the period of this report, the basis between those points was as little as 19 cents, but three times during January and February 2003 the basis was more than $10.[159] Basis values were equal to or below tariff rates for most of assessment period, indicating that pipeline capacity was generally adequate.

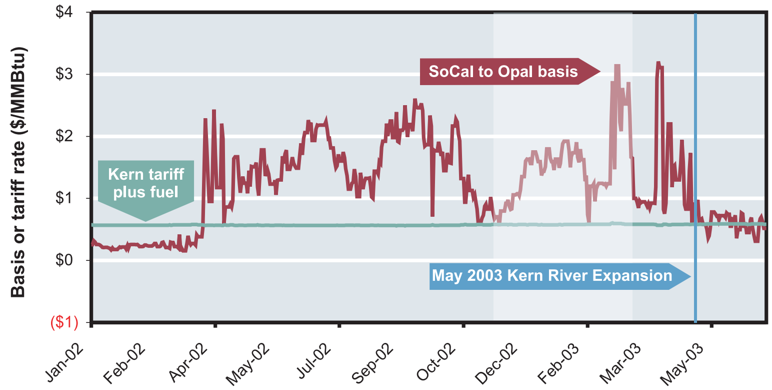
Figure 50 demonstrates the seasonal and market-sensitive nature of pipeline capacity values as imputed from the bundled natural gas markets on a monthly basis. It shows the basis differential, less the tariff rate, plus fuel for several transmission corridors from the East to the West. As shown, basis values have been equal to or below tariff rates for most of the period in study, indicating generally sufficient capacity.

Higher basis differentials occurred in the Rocky Mountain region, especially prior to the Kern River 2003 Expansion Project, the San Juan Basin and occasionally in the Northeast. The Opal to Southern California (SoCal) differential indicated a need for capacity from the Rockies to California beginning in mid-2002. The addition of the Kern River Gas Transmission expansion during the assessment period increased capacity from 845 MMcfd to 1,731 MMcfd on May 1, 2003. Since that time, transient flow conditions have allowed flow to be more than 1,900 MMcfd, and the pipeline has been fully contracted at design capacity. The basis valuations shown in Figure 51 demonstrate the market response to the capacity addition, with the basis differential immediately narrowing to levels consistent with the Kern River tariff for firm transportation.

[158] Basis differential is used as an indicator of the value of additional transportation capacity and is based on the difference in value between the wholesale delivery destination and a benchmarked origin.

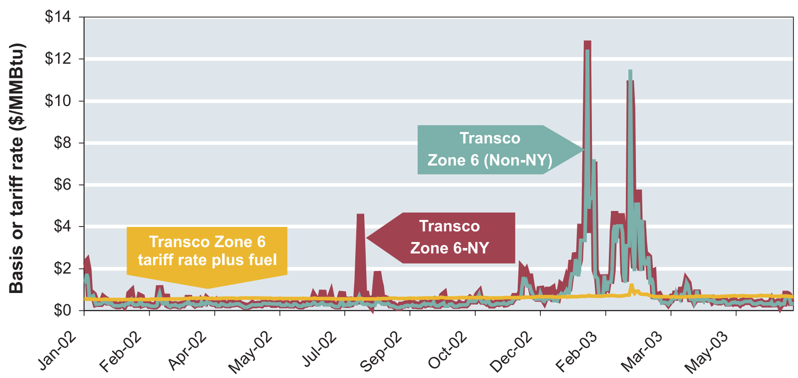
[159] The basis differential calculations are based on daily indices. In the case of Transco Zone 6-NY, the index is based on a smaller volume of transactions than the index for more liquid points.

Figure 51: New infrastructure affects Rocky Mountain basis differentials.



Source: Platts *Gas Daily*, Pipeline Tariffs. Analysis and graphic by OMOI.

Figure 52: Many customers choose to weather short basis blowouts rather than pay for pipeline additions.



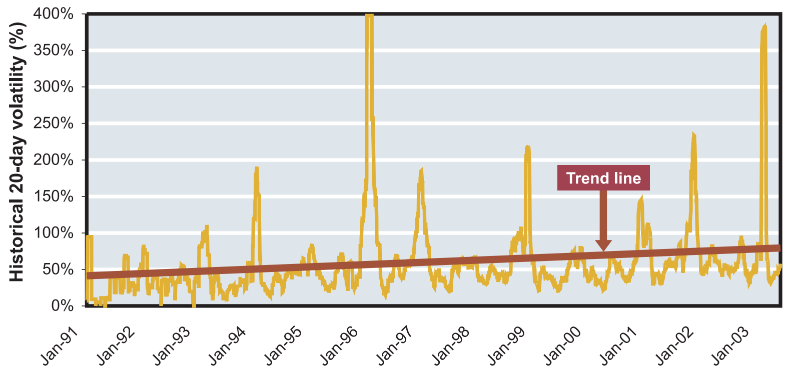
Note: Transco Zone 6 Zone 6-NY and Zone 6-non-NY basis differentials to Henry Hub versus maximum tariff rates plus fuel; lightly shaded bands denote a five-month winter period (November–March).

Sources: Platts *Gas Daily*, Pipeline Tariffs. Analysis and graphic by OMOI.

In the Northeast, the basis, although volatile in the winter, did not exceed tariff rates for extended periods of time. For instance, Transco Zone 6 is a market center covering a six-state area from Virginia to New York City and is characterized by volatility and limited pipeline capacity, especially into New York City. This occasionally causes a large disconnect between transactions of natural gas bound for New York City and natural gas that is destined elsewhere in the Northeast. Historically, in off-peak periods, the basis differentials are normally below the tariff rates. Sometimes, however, basis differentials from the Gulf Coast to Transco Zone 6-NY and Zone 6-non-NY, have exceeded the Transco tariff for relatively brief periods during the winter, with the value significantly higher than the regulated tariff rate at times. Figure 52 demonstrates the Transco Zone 6-NY and Zone 6-non-NY basis differential to Henry Hub versus the tariff rate for Transco firm transportation.

Most often these high basis costs will be borne by generators or LDCs balancing their requirements. Many customers have thus far decided that it is more economic to pay the higher basis costs for a short period of time, rather than subscribe to year-round pipeline additions, either existing or new construction reservation, with the associated, annual demand charges. The reasons for not committing include unwillingness or inability to enter into long-term contracts and the use of alternative means for meeting supply needs. A shipper also may find that it is less costly to pay for gas during short periods of high prices and high volatility than to commit to a long-term contract. Basis differentials that exceed tariffs on a sustained basis indicate that incremental capacity may eventually be needed, but, with efficient pricing signals, the capacity is unlikely to be built until the benefits exceed the costs. The role of basis differentials in analyzing the need for new pipeline construction is discussed in a later Investment subsection.

Figure 53: Henry Hub price volatility increases from the 1990s.



Note: Historical volatility is calculated as the standard deviation of logarithmic returns, log ($price_t$ /$price_{t-1}$), where standard deviation is based on the previous 20 days.

Source: Platts GASdat. Analysis and graphic by OMOI.

Risk Management

Price risk management offers the option of reduced exposure to price volatility, allowing predictable prices. Given the price volatility in the natural gas market, instruments to hedge price risk can offer value to market participants.[160] Price risk management does not guarantee the lowest price possible for the end-user, but it does stabilize the price. Methods to reduce exposure to changing prices include storage, long-term fixed price physical contracts, firm pipeline capacity and financial contracts.

During the assessment period, both the price level and price volatility were higher on average than in the period going back to the early 1990s. In addition to the absolute price level increase in 2002 through 2003, the volatility for next-day physical prices at Henry Hub rose during the assessment period. Figure 53 shows the historical volatility for next-day physical prices along with the next-day prices at Henry Hub from January 1991 through June 2003. The historical volatility is the annualized standard deviation of price changes that actually occurred in the market. Volatility is not a measure of the absolute price level, but a measure of the variation in price, both up and down. Price volatility is important to both natural gas end-users and producers because it signifies the range of possible price outcomes.

From the beginning of 2002 through June 2003, day-to-day physical price volatility at Henry Hub increased to the 70 percent level.[161] The average Henry Hub price for the same period was $4.22/MMBtu. During the 1991 through 1999 time period, the next-day physical price volatility at Henry Hub averaged in the mid-50 percent range and the average price was $2.08/MMBtu. A similar move up in price volatility was evident in the next-month futures prices for 2002–03 as compared to the 1990s. The primary exception between the next-day physical and next-month futures historical volatility was during February 2003, when physical prices saw greater daily changes than did next-month futures prices. The reason for this difference is that the next-day physical prices were responding to the immediate problems of securing enough supply to meet demand, while the futures prices were for the next month's delivery period, where problems in securing supply were expected to be less severe.

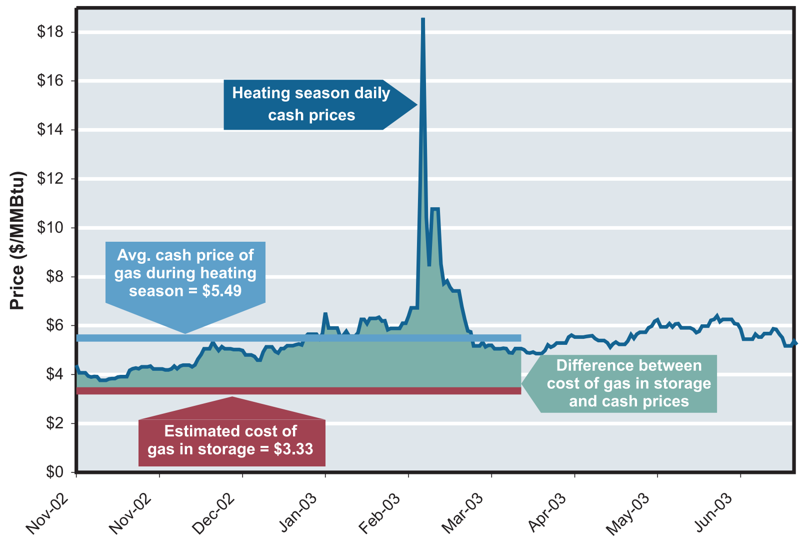
Storage

In using storage, the seasonal spread of prices during the summer and winter is examined to select the best time to purchase gas for storage. Gas injected during the months of April through October is withdrawn and used during November through March. To the extent they have gas stored, market participants have options to avoid higher cash market prices for natural gas during the winter months. Figure 54 shows the estimated cost of gas in storage versus the average cash market price during winter 2002–03, indicating that customers may have benefited when they accessed lower-priced natural gas that had been stored the prior injection season. In future periods, the cost of natural gas drawn from storage may not always be lower than the winter cash market price. Futures can be used to manage the price risk between the injection and withdrawal periods.

160 Price risk is the exposure to the price of the underlying commodity. For example, end-users of natural gas are exposed to rising prices and producers of natural gas are exposed to falling prices.

161 Historical volatility was measured using the next-day Henry Hub prices from Gas Daily for a rolling period of 20 days from January 1991 through June 2003.

Figure 54: Winter 2002–03 cost of gas in storage lower than cash market prices.



Note: The cost of storage and average cash market price is based upon prices at Henry Hub and does not include transportation to other locations. The cost of storage does not include demand charges, injection and withdrawal fees, which vary depending upon the type of storage facility.

Source: Platts *Gas Daily* Henry Hub spot price data for the assessment period; the cost of gas in storage is a volume-weighted average of weekly Henry Hub prices, weighted by weekly EIA injection-withdrawal estimates, for the injection season (April–October 2002). Analysis and graphic by OMOI.

Natural Gas Futures on Nymex and Other Financial Instruments

In addition to storage, the natural gas market has effective financial instruments to hedge price risk. The financial markets for natural gas originated in 1990 with the introduction of Nymex's Henry Hub natural gas futures contract. Since then, the futures contract has grown in use. The natural gas futures contract is now second only to the light, sweet crude oil futures contract in terms of total number of energy futures contracts traded, as evident in Figure 56. At the same time, an OTC market developed for financial products such as swaps and options for price points across the United States and Canada. The futures and OTC markets serve several important functions. First, the markets provide for industry participants to shift their price risk to other parties willing to assume the risk. Second, the financial markets provide price discovery. Price discovery gives industry participants visible prices necessary to execute transactions and make planning decisions. Depending upon the platform and product, prevailing prices of certain financial instruments are more accessible to the public than bilateral transactions done directly between two participants. Market participants primarily used four methods of transacting with natural gas financial instruments:

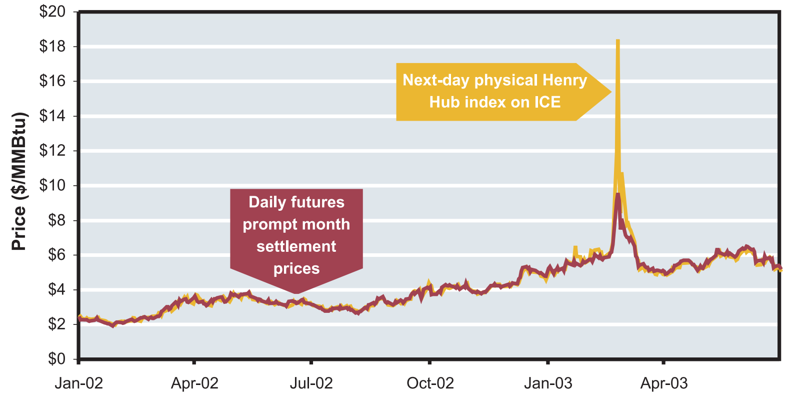
- on Nymex, the futures exchange for the Henry Hub natural gas futures and options contract. Other Nymex products include a set of natural gas futures swaps and basis swaps at various locations,
- on ICE, an electronic exchange for OTC physical and financial products,[162]
- through a voice broker, who matches buyers and sellers in OTC physical and financial transactions, and
- through a direct bilateral transaction between a buyer and a seller.

Generally, during the 18-month assessment period, the Henry Hub physical price converged with the Nymex futures contract expiration price. Financial instruments work as hedges against price exposure in purchasing or selling natural gas if there is a relationship between the financial and physical price. To the extent that physical natural gas and next month futures prices converge, hedges for that month will be efficient. Figure 55 shows the relationship between next-day physical natural gas at Henry Hub and the next month futures settlement prices.[163] While the two

[162] ICE is an internet trading exchange for energy, precious metals, weather and emissions products. Energy trading on ICE began in October 2000. The exchange model for ICE is a many-to-many platform where both buyers and sellers post bids and offers. ICE does not take title to any of the products.

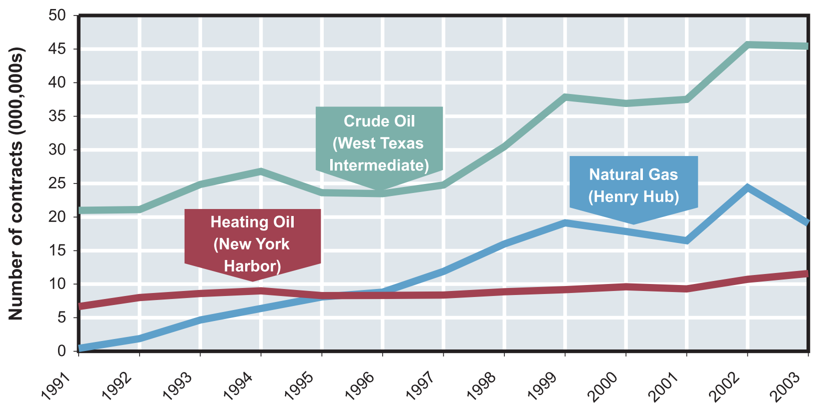
[163] For a discussion of the effects of the February/March 2003 natural gas price spike on Nymex futures see Staff Investigating Team, Federal Energy Regulatory Commission, July 23, 2003, Report on the Natural Gas Price Spike of February 2003, p. 13.

Figure 55: Next-day Henry Hub spot prices move in the same direction as next-month futures prices.



Source: ICE, Bloomberg, L.P. Analysis and graphic by OMOI.

Figure 56: Nymex natural gas futures volumes trend upward.



Source: Nymex. Analysis and graphic by OMOI.

products are different in terms of when they are delivered, they do move together on average. The average difference between the two products was $0.045/MMBtu from January 2002 through June 2003.[164] As the gas futures contract nears expiration (on the third-to-last business day of the month prior to the contract month), the price of the contract and Henry Hub physical gas prices, especially bid week prices for next-month baseload, converge. In other words, if the expiration settlement price and the monthly baseload index for the Henry Hub are the same price, the convergence is “perfect” for hedging purposes.[165] For 2002 through June 2003, the next-month physical index prices from the *Gas Daily* for Henry Hub and the monthly Nymex futures expiration price fell within $0.001/MMBtu of each other on average.[166]

As shown in Figure 56, the natural gas futures volume marked a record year in 2002, with volumes transacted on Nymex for the Henry Hub futures contract and on ICE for the financial swap contracts increasing. The increase was likely due, in part, to the demise of EnronOnline,[167] as participants switched to other trading venues. While still trending upwards, the 2003 Nymex natural gas volumes were less than 2002 volumes.

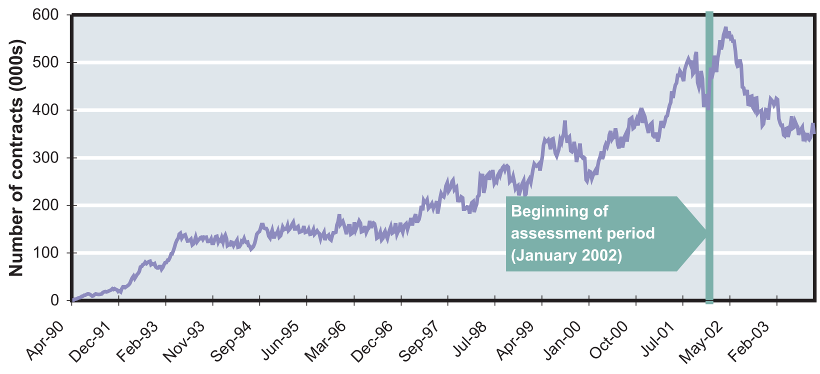
[164] The largest difference between the next-day physical price at Henry Hub and the next-month futures settlement price was $8.837/MMBtu, which occurred on Feb. 26, 2003. On this date, Henry Hub next-day prices rose to $18/MMBtu.

[165] When natural gas futures are used to hedge physical transactions based on the monthly physical market index, the price convergence will result in the participant achieving the price “locked-in” from the hedge. If the futures and physical market prices do not converge, the participant will have either an unplanned gain or loss on the transaction.

[166] The range of differences between the next-month physical price and the next-month futures expiration price was $0.06/MMBtu.

[167] In January 2002, UBS Warburg acquired EnronOnline. The EnronOnline system was renamed under the website UBSWenergy.com. In November 2002, UBS Warburg announced it would shut down the former EnronOnline system.

Figure 57: Nymex open-interest decline points to less forward participation.



Source: CFTC, Commitment of Traders Report. Analysis and graphic by OMOI.

Similarly, the natural gas futures contract open interest declined late in 2002 and through 2003, but remained higher than pre-2000 levels. Open interest is a sign of forward participation in the market. In addition to volume transacted, open interest for the Nymex Henry Hub futures is an indicator of the market's activity level. Open interest is the number of open long or short position (but not the sum of both long and short positions) held at any particular time. It is the total futures position currently held open and not offset by another equal and opposite transaction. Similar to the Nymex volume, open interest grew from 1990 into 2002. Figure 57 shows the weekly total open interest for the Henry Hub futures contract. After peaking in April and May 2002, open interest started to decline in June 2002. As the majority of open interest is held by market participants with positions to be hedged, the decline indicates a possible reduction in their forward trading in 2003.

Credit Risk

During the assessment period, some merchant energy companies reduced their marketing and trading activity and one large merchant energy company declared bankruptcy.[168] As a result of the decreased number of participants in the market and weakened financial conditions of other participants, there was a rise in credit risk, or the risk of a change in the counterparty's credit quality or rating. Directly related to this is the default risk (the risk of the counterparty not performing on the contract), which may have increased during the assessment period.

The rise in credit risk posed several problems for the market, including:

- increased difficulty finding creditworthy counterparties,
- decreased number of counterparties willing to transact long-term structured contracts, and
- increased bid-ask price spreads found in executing purchases and sales, which affects price volatility.

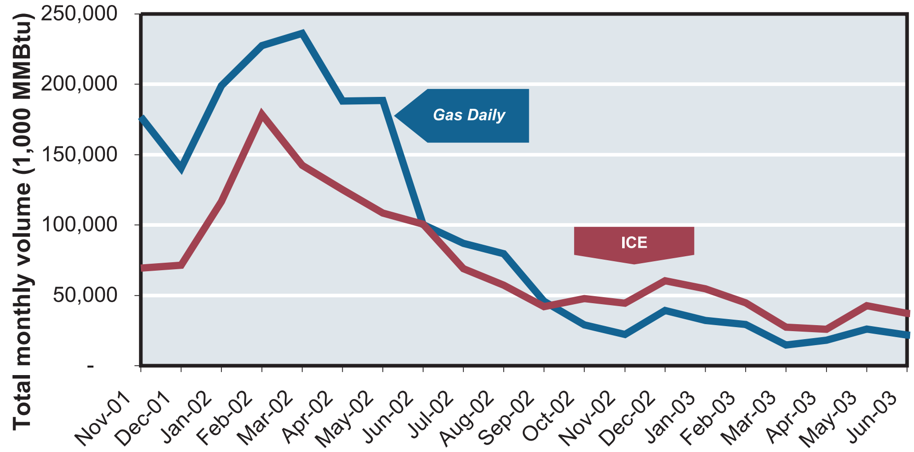
Prior to 2002, there were no central clearinghouses for bilateral or OTC physical and financial transactions. Previously, the prevailing risk in wholesale natural gas purchases and sales was a change in the absolute price level as it affected open (or unhedged) positions such as buying natural gas at an indexed price. Credit risk was managed primarily through relying on the credit quality of the counterparty or setting up contract provisions to limit the financial exposure via margining and/or netting transaction exposures against one another. These types of contract provisions were not widely used, and there were few sophisticated credit management models in place to measure not only current credit exposure, but potential exposure.

Another method to manage credit risk is through a central clearing facility, also known as a clearinghouse. By using a clearing service, the counterparty credit risk in bilateral transactions is transferred to the clearing organization. With any clearinghouse, various items need to be examined such as the ability of the clearinghouse to guarantee performance of the contract in times of a price spike, necessary requirements for members of the clearinghouse and all associated costs of clearing.[169] For example, in buying and

168 NRG Energy, a wholly owned subsidiary of Xcel Energy, filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy code on May 14, 2003; by Dec. 5, 2003 it has successfully completed its Chapter 11 reorganization and emerged from bankruptcy. In addition, within two months after the assessment period, two additional merchant energy companies declared bankruptcy. On July 8, 2003, PG&E's National Energy Group voluntary filed in U.S Bankruptcy Court in Maryland under Chapter 11, in default on $2.9 billion in debt. It was renamed as National Energy & Gas Transmission by Maryland Court, Oct. 3, 2003 as part of reorganization. Mirant sought U.S. Bankruptcy Court protection on July 14, 2003 in northern Texas.

169 The CCRO white paper on Credit Risk Management reviews the attributes of clearinghouses (see www.CCRO.org).

Figure 58: Henry Hub volumes reported to index publishers decline in mid-2002.



Note: ICE data have been modified to make them comparable to *Gas Daily* data. Since *Gas Daily* volumes include both buy and sell sides of transactions and ICE volumes include only the sell side of transactions, ICE volumes were doubled.

Source: Platts *Gas Daily* and ICE. Analysis and graphic by OMOI.

selling futures contracts, Nymex acts as a central clearing facility and guarantees performance of the futures contracts. Costs include the cost of capital for funds posted for margin requirements, which will vary depending on the size of the position, any offsetting positions and the movement of the underlying price.

Nymex and ICE introduced new products starting in spring 2002 for credit clearing.[170] These products were used immediately by market participants. ICE began offering clearing services in March 2002 for natural gas, electricity and crude oil products. The natural gas clearing is done via the London Clearing House.[171] Nymex launched its clearing service in May 2002 for standardized natural gas, electricity, crude oil and refined products. Late in 2002, Nymex offered trading and clearing for futures contracts based on OTC products such as basis swaps at various defined locations. The swaps are financially settled, whereas the Henry Hub futures contracts involve physical settlements. While these products are not different in specifications from products traded in the OTC market, the service allows for electronic trading of the products and Nymex clearing.[172] The clearing products are offered on Nymex's ClearPort system, which started in early 2003 and which had 26 natural gas products at the end of the assessment period. The industry use of the clearing products is evident through the volumes of natural gas cleared on Nymex and ICE. From inception through late-September 2003, Nymex cleared the equivalent of 11.7 quadrillion Btu of natural gas. From inception through early November 2003, ICE cleared the equivalent of 20.6 quadrillion Btu of natural gas.[173]

Other actions taken by the industry to promote credit risk management include the publication of the Committee of Chief Risk Officers' (CCRO) white paper in fall 2002 on credit risk management, which describes best practices including:

- establishment of credit policies,
- measuring credit value-at-risk,
- mitigating credit risk, and
- use of credit provisions within master agreements of organizations like the International Swap Dealers Association (ISDA) and North American Energy Standards Board (NAESB).

The CCRO document discusses credit derivatives and multilateral clearing as means to minimize credit risk.

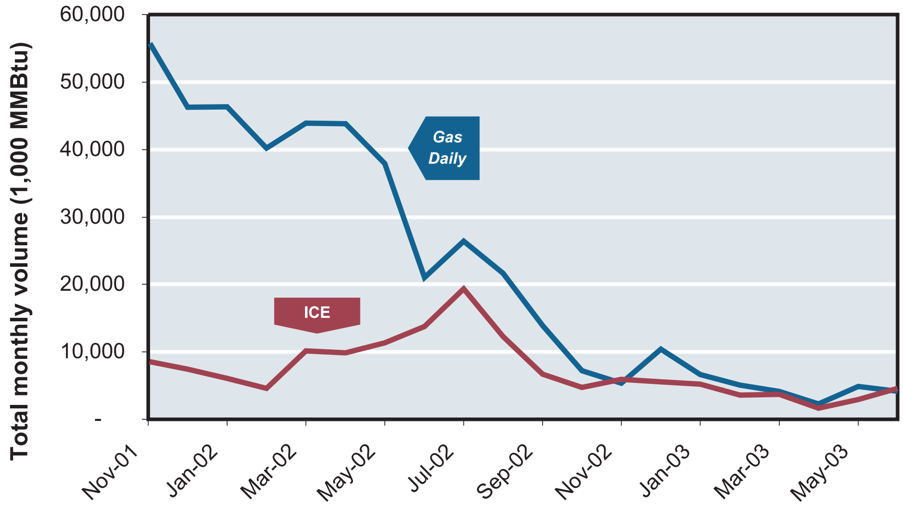
170 Credit clearing is the mechanism for settling mutual claims, the result of which is that the risk that a company might fail to fulfill its contract is pooled among many companies.

171 The London Clearing House and the Nymex Clearing House are registered Derivatives Clearing Organizations with the CFTC.

172 Transactions not executed on Nymex which fit the ClearPort product specifications may be cleared on Nymex. The transactions are transferred to the Nymex Clearing House via an exchange of futures for physical (EFP) or an exchange of futures for swaps (EFS).

173 ICE and Nymex press releases. To better compare cleared volumes, totals include volumes cleared outside the assessment period.

Figure 59: Transco Zone 6-NY volumes reported to index publishers decline in mid-2002.



Note: ICE data have been modified to make them comparable to *Gas Daily* data. Since *Gas Daily* volumes include both buy and sell sides of transactions and ICE volumes include only the sell side of transactions, ICE volumes were doubled.

Source: Platts *Gas Daily* and ICE. Analysis and graphic by OMOI.

Transparency

Physical Market Price Transparency and Indices

Price transparency for natural gas varies by geographical region due to differences in liquidity in local markets. Transparency also varies depending on whether it is for a physical or financial product. Published price indices provide transparency for the physical price of natural gas and benchmarks for contract purposes. An index can be a survey-conducted composite price, established on the basis of systematically processed geographic-specific prices for daily or monthly contracts reported to an index provider. An index can also be a composite calculation, such as a transaction price based on and weighted by transactions on an exchange, such as ICE.

Confidence in survey-conducted indices declined early in the assessment period due to allegations and announcements of misreporting transactions to survey providers. Early in the assessment period, revelations that price indices may have been manipulated helped to erode confidence in the market and in price discovery mechanisms. The industry's reliance on indices and the role of indices in price transparency are keys to understanding the concern generated by these disclosures.[174] Many contracts, both physical and financial, are tied to indices calculated from daily or monthly physical prices. In addition, indices are used to settle swaps, to establish pipeline cash-out figures and to benchmark LDC gas purchase performance. Because indices are integral to the way the industry does business, concerns that the indices might be unreliable ultimately precipitated modifications in the informal processes that supported index development.

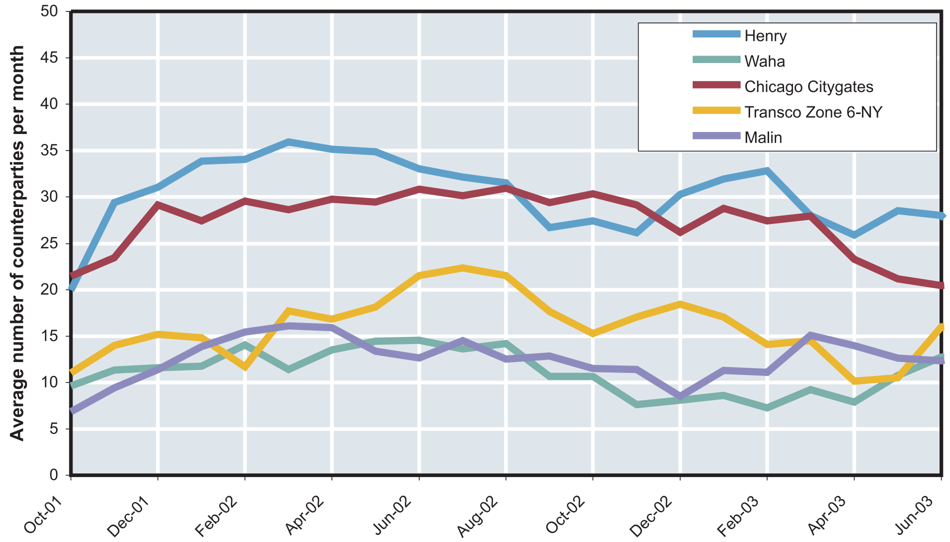
The bankruptcies and cutbacks at large merchant energy companies affected the number of transactions both reported and transacted. In late-2001, Enron Corp. declared bankruptcy.[175] For a time following this announcement, the natural gas market was not affected significantly, because other participants stepped in to fill the void left by Enron. In April 2002, a wave of information on wash trading further unsettled market participants and caused a decline in stock prices for many energy merchant companies.[176] Throughout 2002, some once dominant industry participants closed their trading units or ceased trading speculatively; they shifted to trading strategies based upon assets such as

[174] In an announcement in mid-July 2003, the CFTC named 19 companies under investigation in matters related to price reporting; of those 19, seven—AEP, CMS Energy, Dynegy, Sempra Energy, Xcel, West Coast LLC and Williams—had already admitted that some staff had reported inaccurate prices. Gas Daily, July 17, 2003.

[175] On Dec. 2, 2001, Enron Corp. filed for Chapter 11 bankruptcy.

[176] On May 21, 2002 under FERC Docket No. PA02-2-000, Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, sellers of wholesale electricity and/or ancillary services in the WSCC were sent the request to respond to questions on physical and financial transactions during 2000 and 2001.
Under FERC Docket No. PA02-2-000, Final Report on Price Manipulation in Western Markets, Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, March 2003, wash trades are generally defined as a prearranged pair of trades of the same good between the same parties, involving no economic risk and no net change in beneficial ownership.

Figure 60: The number of counterparties transacting next-day trades varies by location.



Source: ICE. Analysis and graphic by OMOI.

storage and pipeline capacity.[177] Gradually filling the void left by the exit of some of the merchant energy companies, new and existing market participants began marketing and trading. Some of the existing companies include marketing affiliates of producers and LDCs and some of the new market participants are financially oriented, such as hedge funds.

The direct effect of the misreporting to index providers and the decline in market participants is seen in the number of transactions reported to the *Gas Daily* index[178] for next-day physical natural gas products. The effect of the decline in market participants is also seen in the number of transactions in the same products traded on ICE. Figure 58 and Figure 59 show the total monthly volume of next-day physical transactions reported to *Gas Daily* and transacted on ICE for November 2001 through June 2003.[179] Figure 58 shows the total monthly volume of next-day physical products for Henry Hub as an example of a supply point. Figure 59 shows the total monthly volume of next-day physical products at Transco Zone 6-NY as an example of a consuming market area point.

Both the *Gas Daily* and ICE volumes display an uptrend in physical next-day volumes in early-2002 after the Enron bankruptcy announcement, but the short-term increase was followed by a sharp decline in spring 2002 as shown in Figure 58. The initial increase was likely due to the closure of EnronOnline, Enron's electronic trading platform which, prior to 2002, was used heavily in the market for physical and financial trades. With the exit of Enron, market participants executed their trades on ICE and Nymex, and used voice brokers and direct bilateral transactions. The likely reasons for the eventual decrease in volume, both reported and transacted, are multiple:

- Fewer participants were in the market.
- Remaining participants completed fewer transactions.
- Reporting procedures to index publications have changed because of misreporting, including inflated trading volumes.[180]
- The number of participants willing to report transactions to survey-based index publications declined.
- Inflated reporting as a result of wash trades decreased. OMOI believes the practice of engaging in natural gas and electricity "wash trades" to inflate trading activity and revenue declined in response to the effect of

177 Company press releases and energy trade press.

178 Platts *Gas Daily* is one of several survey-based index providers, which include NGI's *Daily Gas Price Index* and BTU's *Daily Gas Wire*.

179 Platts *Gas Daily* index volumes may include both the purchase and sale side of a transaction; there are no data available to verify the extent to which this occurs. ICE volumes are representative of one side, the sales side, of each transaction.

180 On April 30, 2003 under FERC Docket Nos., PA03-1-000, PA03-2-000, PA03-3-000, PA03-4-000, PA03-5-000, PA03-6-000, PA03-7-000, PA03-8-000, PA03-9-000, PA03-10-000, PA03-11-000, American Electric Power Co., Aquila Marketing Service, Coral Energy Resources, LP, CMS Marketing Services & Trading, Dynegy Inc., Duke Energy Trading and Marketing LLC, El Paso Merchant Energy LP, Mirant Americas Energy Marketing LP, Reliant Resources Inc., Sempra Energy Trading Corp., and Williams Energy Marketing & Trading Co. were ordered to show that they corrected their internal processes for reporting trading data to the trade press or that they no longer sell natural gas at wholesale.

wash trading disclosures on companies' stock prices and FERC's investigation into Enron and the California energy crisis of 2000–2001.

The decline in the 2002 next-day volumes is also evident in the transactions on ICE, as shown in Figure 58.[181] For Transco Zone 6-NY, shown in Figure 59, the downtrend appears to have stopped and the volumes began to increase after reaching a low in April 2003. Comparison of Figure 58 and Figure 59 shows that the number of transactions at Henry Hub exceeds transactions reported for Transco Zone 6-NY. For some locations, there are a limited amount of transactions underlying the index price.

The Commission and industry took action to restore confidence in the price formation process. Early in 2003, industry groups developed best practice guidelines and recommended codes of conduct for energy trading.[182] Price index developers urged the industry to increase the level of fixed-price trading and rely less heavily on contracts indexed to survey prices, as well as to report trade data to ensure accurate indices.[183] Many in industry and price index publishers also requested that the Commission take steps to support renewed confidence in price indices.[184]

Further transparency in the physical market developed late in the assessment period. For the monthly price indices, *Gas Daily* and Natural Gas Intelligence started associating each location with a "tier" for information on the reported volume and number of transactions for the bidweek in June 2003, effective for the July 2003 indices.[185] Beyond listing the total transactions per location, in June 2003 ICE started to publish daily the number of counterparties and number of transactions at each location for transactions executed for the next-day physical product as well as to publish the same information for monthly bid week physical transactions. This information gives market participants the ability to examine liquidity factors and market trends at multiple locations.

The number of counterparties transacting at the supply points varied from those at the market area points, as shown in Figure 60. Henry Hub had a large number of counterparties in comparison to other points and experienced a decline in 2002 coinciding with the fall in transacted volumes reported. The number of counterparties began to stabilize and recover slightly at Henry Hub and other points through 2003.

Monthly indices are often less liquid than day-ahead indices. For transactions reported to survey providers, the decision to use index-based monthly (baseload) contracts, instead of fixed-price contracts, affects the volume, reducing the pool of trades used for calculating fixed-price indices and limiting price transparency in the market. The limited liquidity for some monthly contracts is evident on ICE,[186] where the month-ahead fixed-price products at Henry Hub are a small percentage of the total volume transacted for next-day products through the course of a month. From January 2002 through June 2003, the total volume of month-ahead fixed-price products at Henry Hub averaged less than 6 percent of the total volume of next-day fixed-price products. However, the ratio of month-ahead fixed-price product volume to next-day fixed-price product volume is not the same for all pricing points. For example, at Waha (West Texas), the total volume of month-ahead fixed price products averaged approximately 100 percent of the total volume of next-day fixed-price products during the same period. The total volume that industry participants transact for month-ahead products using other methods—by voice brokers or through direct bilateral trades—is not known because there are no reporting requirements for natural gas physical and financial transactions outside of futures transactions.

Forward Price Transparency

Prices in forward months are necessary for participants planning hedges and making investment decisions. During the assessment period, forward price transparency was available through the Nymex Henry Hub futures contract. While physical price discovery relied on day-ahead and month-ahead published indices, most forward price transparency was a function of financial markets. During the assessment period, Nymex offered trading in the Henry Hub contract out for six consecutive years. Forward price transparency at locations other than Henry Hub were available for shorter periods of time.

Forward price transparency improved during the assessment period with the introduction in 2002 of financial OTC swaps on Nymex's ClearPort system. Prior to this introduction, forward contracts at various locations were available via ICE and OTC voice brokers, but the ClearPort swaps made prices publicly visible.

181 Volumes transacted on ICE are potentially a subset of the volume reported to Gas Daily. Given the data available, OMOI does not know the size of the ICE volumes reported by market participants to Gas Daily.

182 In March 2003, the CCRO issued transition guidelines to help increase the amount of data supplied to index developers.

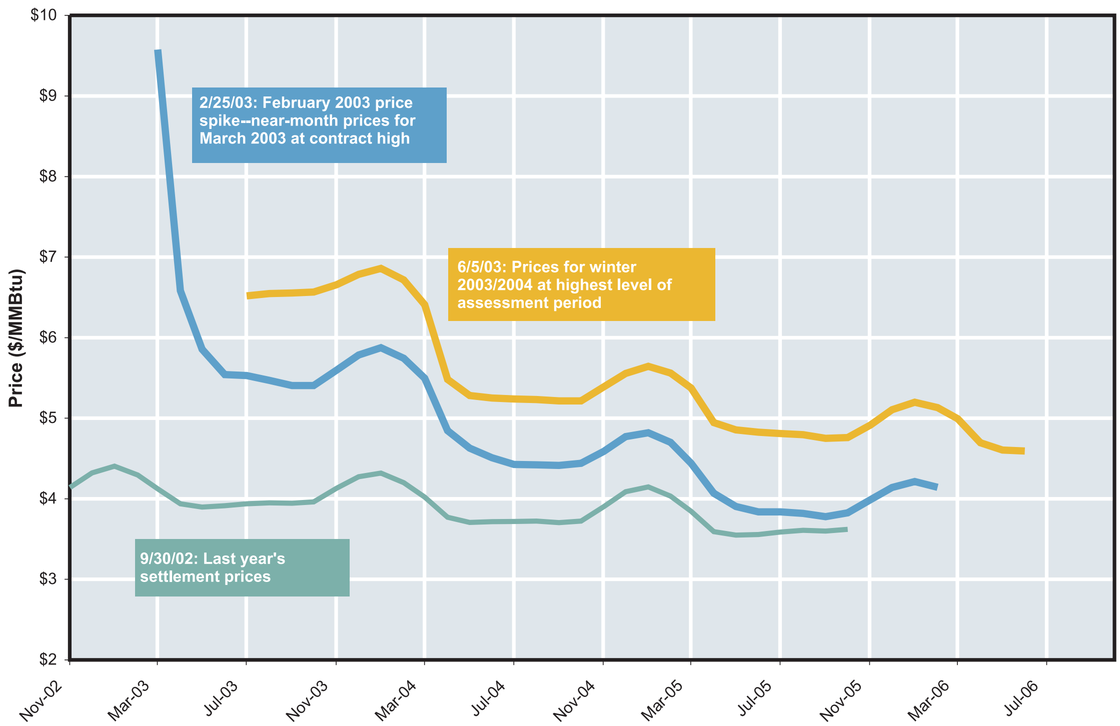
183 Docket No. AD03-7

184 In response to requests for Commission action, the Commission issued the Policy Statement on Natural Gas and Electric Price Indices, July 24, 2003. The Policy Statement presented guidelines for both index developers and price reporters. In addition, the Commission provided assurance to companies that, if they follow the Policy Statement guidelines, they will not be subject to penalties for inadvertent errors. In October 2003, the Commission conducted a survey of 266 energy companies to determine whether, how, and to what extent they report price data to index developers.

185 For example, "tier 1" in Gas Daily is for locations with volumes of at least 100,000 MMBtu/d and at least 10 trades.

186 Unlike the day-ahead natural gas product, only ICE published the specific volumes, number of transactions and number of counterparties for month-ahead physical natural gas products per delivery point for the months of the assessment period

Figure 61: In 2003, forward price expectations shift upward.



Source: Platts *Gas Daily* for Nymex forward curve. Analysis and graphic by OMOI.

Investment

Forward Price Expectations and Production

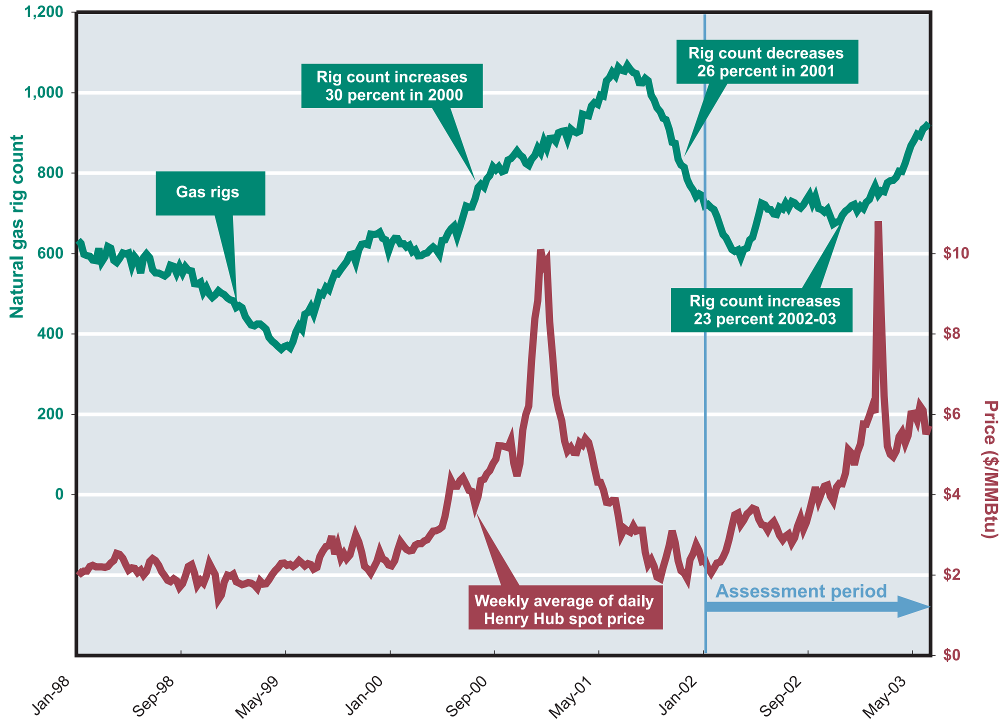
Forward price expectations increased in 2003, sending signals to investors that higher natural gas prices might be sustainable and additional investment might be justified. Figure 61 displays the forward 36 month futures settlement prices on given days during the assessment period. In September 2002, the forward curve was centered at about the $4.00/MMBtu price level. By February 2003, the forward curve had shifted up. Prices were at their highest level for the first several months (March and April 2003) on the curve due to prolonged cold weather, low storage levels and pipeline constraints. The short-term supply and demand factors from February 2003 subsided and were replaced by longer-term concerns about the supply of natural gas and refilling storage for the 2003–04 heating season, reflected in price increases in early June 2003. The futures forward curves and their implied volatility are important because they influence the decision-making of industry participants to drill for natural gas, employ physical hedges like natural gas storage injections, engage in forward financial hedging transactions or sponsor infrastructure projects (e.g., LNG regasification terminals and related storage facilities).

Despite higher gas prices since early-2003, a limited new supply response resulted. Increases in gas-directed drilling by producers in North American did not match peak 2001 rig counts (see Figure 62) and drilling did not substantially relieve tightness in the overall North American supply and demand balance. Significant investments in upstream activity began to be made; companies dedicated about 900 gas-directed rigs to drilling at the end of the assessment period in response to expectations of higher natural gas prices (shown in Figure 62). Several factors, however, may account for why recent high gas prices have not stimulated more gas-directed drilling, including the following:

- Companies have dedicated a portion of incremental revenues from high gas prices to strengthen balance sheets instead of deploying more rigs.[187]
- Companies may have delayed upstream capital commitments due to uncertainty about the sustainability of current price levels and extreme price volatility.
- Earnings associated with developing mature geologic plays in the United States may be less favorable to "super-major" producers than making investments abroad.

[187] CERA, "Can We Drill Our Way Out of the Supply Shortage," Decision Brief, October 2003 and follow-up teleconference call with CERA in October 2003.

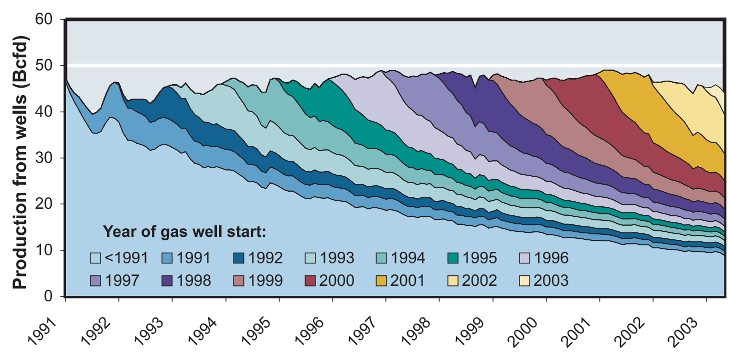
Figure 62: 2003 producer drilling response to high prices moderate.



Note: Prices not adjusted for inflation.

Source: Platts GASdat, Platts *Gas Daily* and Baker-Hughes. Analysis and graphic by OMOI.

Figure 63: More drilling needed to maintain production.



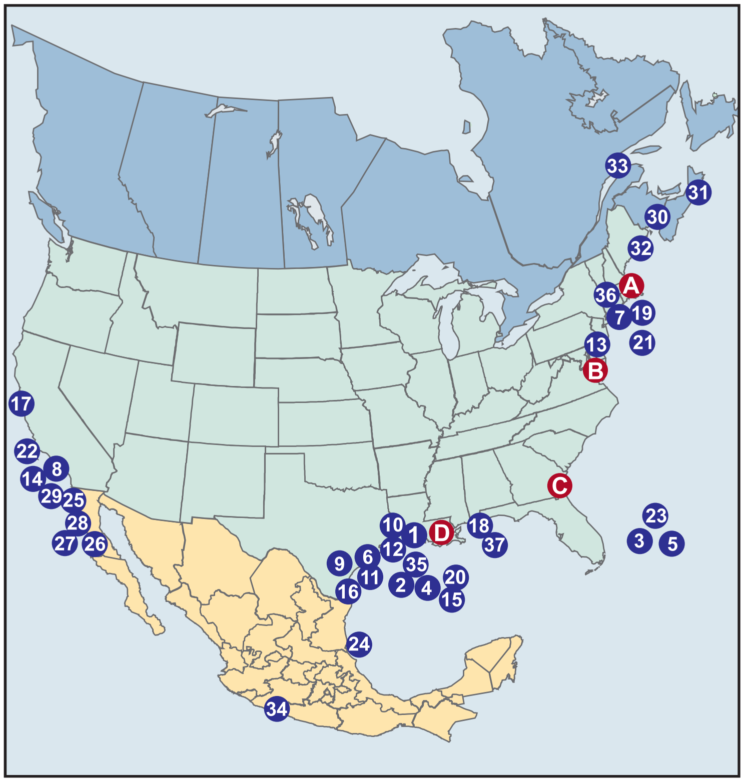
Note: Daily wet gas production from gas wells, by year of production start, total U.S.

Source: NPC, "Balancing Natural Gas Policy," September 2003.

- Restrictions on access to natural gas resources located on public lands may have foreclosed investment opportunities.[188]

[188] NPC, "Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy," September 2003.

Figure 64: Map and output capacities of existing and proposed LNG terminals.



Existing Terminals with Expansions

A. Everett, MA	1.0 Bcfd	Tractebel
B. Cove Point, MD	1.0 Bcfd	Dominion
C. Elba Island, GA	1.2 Bcfd	El Paso
D. Lake Charles, LA	1.2 Bcfd	Southern Union

Approved Terminals

1. Hackberry, LA	1.5 Bcfd	Sempra Energy
2. Port Pelican	1.6 Bcfd	ChevronTexaco
3. Bahamas	0.8 Bcfd	AES Ocean Express*
4. Gulf of Mexico	0.5 Bcfd	El Paso Global

Proposed Terminals – FERC

5. Bahamas	0.8 Bcfd	Calypso Tractebel
6. Freeport, TX	1.5 Bcfd	Cheniere/Freeport LNG Dev.
7. Fall River, MA	0.8 Bcfd	Weaver's Cove Energy
8. Long Beach, CA	0.7 Bcfd	SES/Mitsubishi
9. Corpus Christi, TX	2.6 Bcfd	Cheniere LNG Partners
10. Sabine, LA	2.6 Bcfd	Cheniere LNG
11. Corpus Christi, TX	1.0 Bcfd	Vista Del Sol/ExxonMobil
12. Sabine, TX	1.0 Bcfd	Golden Pass/ExxonMobil
13. Logan Township, NJ	1.2 Bcfd	Crown Landing LNG – BP

Proposed Terminals – Coast Guard

14. California Offshore	1.5 Bcfd	Cabrillo Port – BHP Billiton
15. Louisiana Offshore	1.0 Bcfd	Gulf Landing – Shell

Planned Terminals

16. Brownsville, TX	N/A	Cheniere LNG Partners
17. Humboldt Bay, CA	0.5 Bcfd	Calpine
18. Mobile Bay, AL	1.0 Bcfd	ExxonMobil
19. Somerset, MA	0.7 Bcfd	Somerset LNG
20. Louisiana Offshore	1.0 Bcfd	McMoRan Exp.
21. Belmar, NJ Offshore	N/A	El Paso Global
22. So. California Offshore	0.5 Bcfd	Crystal Energy
23. Bahamas	0.5 Bcfd	Seafarer - El Paso/FPL
24. Altamira, Tamulipas	1.1 Bcfd	Shell
25. Baja California, MX	1.0 Bcfd	Sempra & Shell
26. Baja California	0.6 Bcfd	Conoco-Phillips
27. Baja Calif. Offshore	1.4 Bcfd	ChevronTexaco
28. Baja California	0.6 Bcfd	Marathon
29. California – Offshore	0.5 Bcfd	ChevronTexaco
30. St. John, NB	0.8 Bcfd	Irving Oil & Chevron Canada
31. Point Tupper, NS	0.8 Bcfd	Access Northeast Energy
32. Harpswell, ME	0.5 Bcfd	Fairwinds LNG – CP & TCPL
33. St. Lawrence, QC	N/A	TCPL and/or Gaz Met
34. Lázaro Cárdenas, MX	0.5 Bcfd	Tractebel
35. Gulf of Mexico	1.0 Bcfd	ExxonMobil
36. Providence, RI	0.5 Bcfd	Keyspan & BG LNG
37. Mobile Bay, AL	1.0 Bcfd	Cheniere LNG Partners

Note: *U.S. pipeline approved; LNG terminal pending in Bahamas

Source: FERC. Graphic by OMOI.

Table 21: Storage capacity control shares by category of users.

Category of storage capacity user	Share of storage capacity controlled
Local distribution companies	73%
Pipelines	8%
Others (marketers, generators, etc.)	19%

Source: International Gas Consulting, "The Evolution of Underground Natural Gas Storage: Changes in Utilization Patterns," submitted to the American Gas Association, August 2001.

Decline Rates of Production

While drilling activity appears to have begun to accelerate at the end of the assessment period, leading to increased production, recoveries per natural gas completion have diminished. New production has tended to have a higher initial rate due to improved technology, thereby increasing cash flow. However, higher initial production has tended to result in increased production decline rates, especially when coupled with smaller recoveries per natural gas well completion due to declining reservoir quality. This creates the need for more drilling to maintain production, as shown in Figure 63. In other words, each additional well increases production for a shorter period of time and a higher rig count is required to maintain production.

The reliance on aggressive drilling to maintain production has led to concerns that supply growth in traditional areas, mainly in the Rockies and Gulf of Mexico shelf, will only serve to offset accelerating decline rates and that large-scale resources such as LNG and Arctic natural gas will be required to meet future demand.

LNG Investment

Natural gas market fundamentals have helped renew interest in LNG as a source of North American supply during the assessment period. Higher natural gas prices increased imports of LNG at existing U.S. import terminals and companies proposed the development of more than 30 LNG receipt terminals in North America, which appear to offer profitable opportunities[189] for growth.[190] Improvements in technology and international competition drove costs of importation to $2.50–$4.00/MMBtu for greenfield projects.[191] Figure 64 shows the location and capacity of proposed new LNG import terminals.

The potential to implement the proposed investments will depend on many factors. The number of projects actually realized will be less than those announced. First, investors and lenders must be convinced that higher natural gas prices are sustainable, be able to manage risk through a derivative contract or find a creditworthy counterparty willing to enter into a long-term contract. Second, project customers must be creditworthy and willing to commit to long-term contracts. While long-term contracts are also necessary for pipeline investments, the $2 billion–$5 billion investment required for a complete LNG train magnifies the challenge of securing sufficient contract commitments.

Siting and permitting factors may slow LNG development. Certification and assessments conducted by multiple federal authorities, including FERC, EPA, DOE, the U.S. Coast Guard and the State Department and state and local authorities, can be a multi-year process. To expedite the process, the Commission is coordinating with the U.S. Coast Guard and the Department of Transportation through an inter-agency working group designed to provide seamless review of project siting, safety and security. The NPC is seeking certification permitting periods of one year or less.[192] Locally, substantial work will be needed to address security and environmental concerns of multiple jurisdictions and communities.

Storage Capacity Investment

Historically, as detailed in Table 21, most working gas in storage is controlled by LDCs.

Investment in new storage capacity was slow during the assessment period. Capacity additions to storage have leveled off in the past few years. Total underground storage capacity increased 1.4 percent (116 Bcf) in 2001 from 2000. The increase from 2001 to 2002 was 0.3 percent (23 Bcf). The Commission certificated about 53 Bcf of new storage capacity and nearly 3 Bcfd of deliverability during the assessment period.

Recent storage additions, including the Lodi and Wild Goose facilities in California, illustrate that market partici-

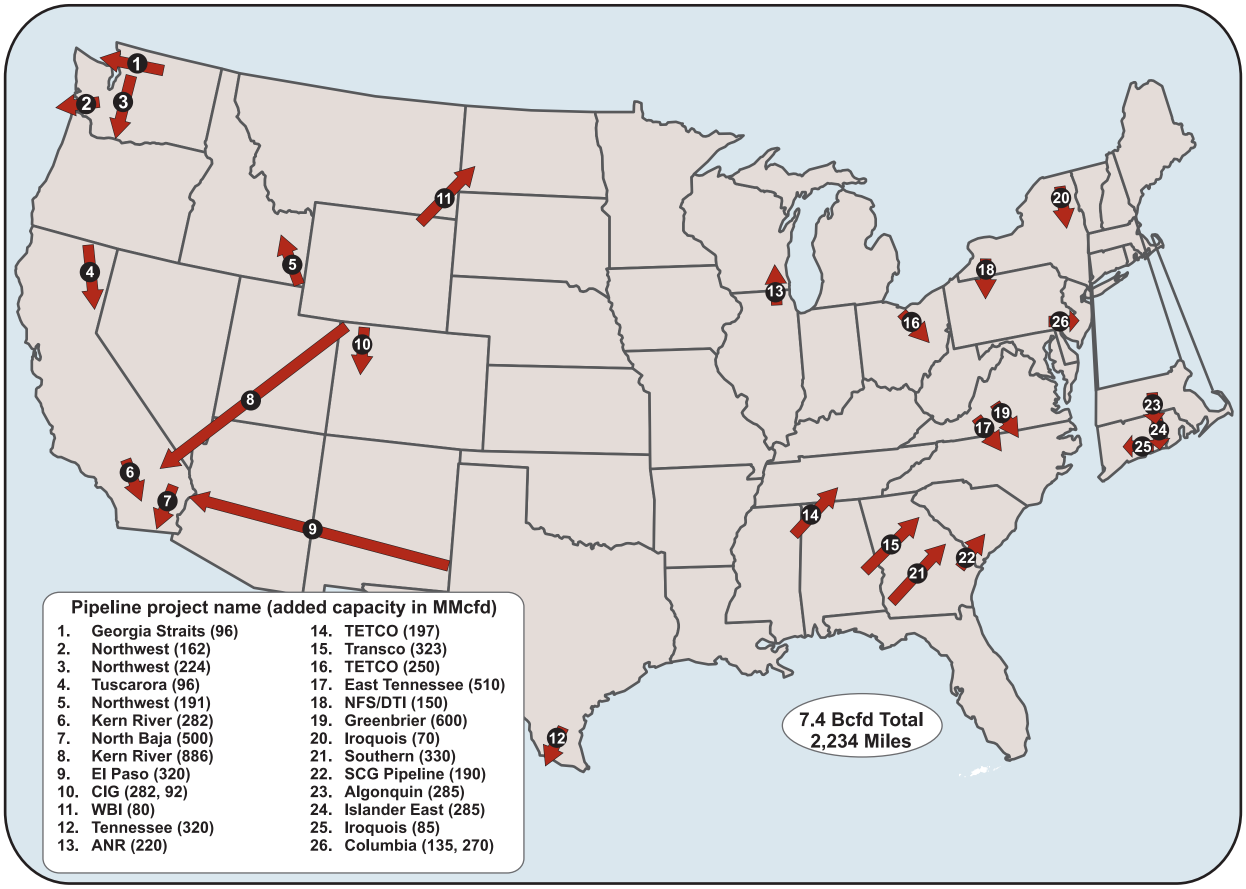
189 Ibid, p. 3.

190 Marie N. Fagan, CERA, "Can We Drill Our Way Out of the Supply Shortage," North American Natural Gas, p. 1, October 2003.

191 Scott, Madden & Associates, Energy Industry Update: Highlights of Significant Trends and Emerging Trends in the Energy Industry, 2003, p. 18.

192 NPC, "Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy," Volume I, Summary of Findings and Recommendations, September 2003, p. 64.

Figure 65: FERC certifications signal new pipeline investments.



Note: Map includes major pipeline projects (70 MMcfd or greater) certificated from Jan. 1, 2002 to June 30, 2003.

Source: FERC. Graphic by OMOI.

pants continued to find value in storage investments. Lodi and Wild Goose are owned by independent storage developers who are typically aggressive users of storage facilities, using multi-cycle, high-deliverability facilities to execute gas pricing arbitrage strategies and hub-to-hub trading activities.[193] Nevertheless, the slow rate of recent storage capacity additions may reflect the many challenges to storage investment, especially nontraditional, high-deliverability storage. These investment hurdles include finding, acquiring and developing a site with suitable geologic characteristics, establishing binding, long-term firm contracts for capacity services, managing the regulatory process and securing financing and counter-party credit.

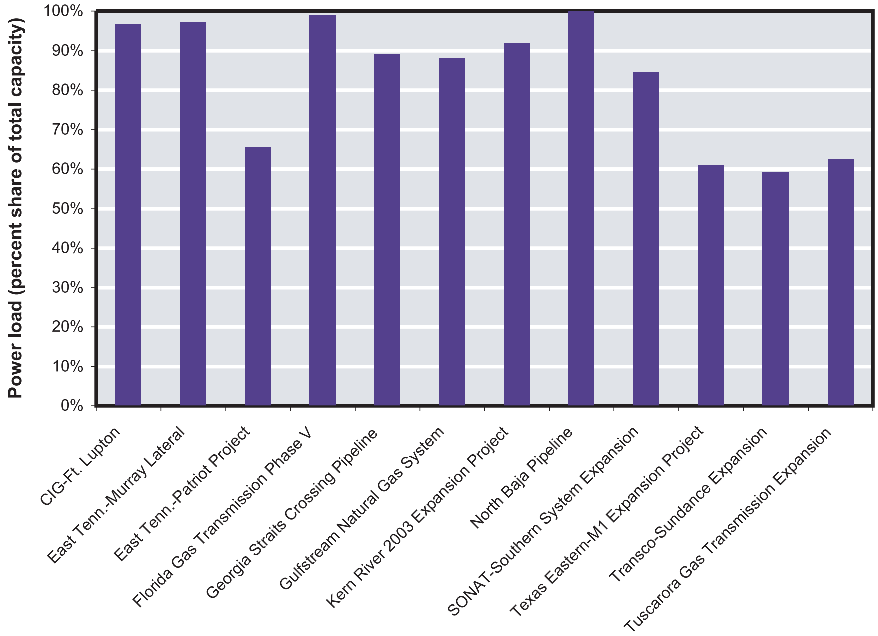
A regulatory issue for storage developers was illustrated in the recent Red Lake Storage application to construct and operate facilities in Mohave County, Ariz. and the request to charge market-based rates for the facilities.[194] The Commission denied the request for market-based rates because of a lack of comparable services in the geographic area and, hence, the potential for market power. This demonstrates a paradox in that a developer was not able to get market-based rate approval in a region because it was lacking in storage alternatives. The result is that in the areas most needing storage, denying market-based rates may potentially hinder development. Another regulatory concern is that LDCs hesitate to make the long-term commitments to secure natural gas supplies (and therefore support infrastructure investments such as storage) when retail unbundling creates uncertainty about their natural gas requirements.

The ability to secure long-term capacity contracts for storage was further limited by the credit problems of some

[193] International Gas Consulting, "The Evolution of Underground Natural Gas Storage: Changes in Utilization Patterns," submitted to the American Gas Association, page 27-28, August 2001.

[194] 103 FERC 61277, (Order Denying rehearing of FERC's Jan. 30, 2003 Order & Terminating proceedings regarding Red Lake Gas Storage, LP under docket CP02-420 et al).

Figure 66: New pipeline firm subscribers mostly power generation shippers.



Source: FERC, interstate natural gas pipeline applications for Certificates of Public Convenience and Necessity. Graphic and further analysis by OMOI.

of the customers, especially power generators. Valuing multi-cycle, high-deliverability storage is more difficult than assigning quantitative value to pipeline and generation assets. Given its higher cost, the economics of high-deliverability storage are dependent upon deriving trading benefits from volatility in addition to the traditional seasonal arbitrage. The advantages of trading around volatility or real option value have been difficult to quantify, especially with the collapse in the wholesale trading sector and corresponding reduced liquidity.

Substitutes for storage may have been a deterrent to increased investment. For example, development of new pipeline capacity infrastructure partially reduces the need for natural gas storage capacity, as does remarketed pipeline capacity bundled with supply and marketed as a peaking service. Market participants could also choose from an assortment of financial product offerings to hedge price risk without using physical instruments like storage.

Pipeline Investment

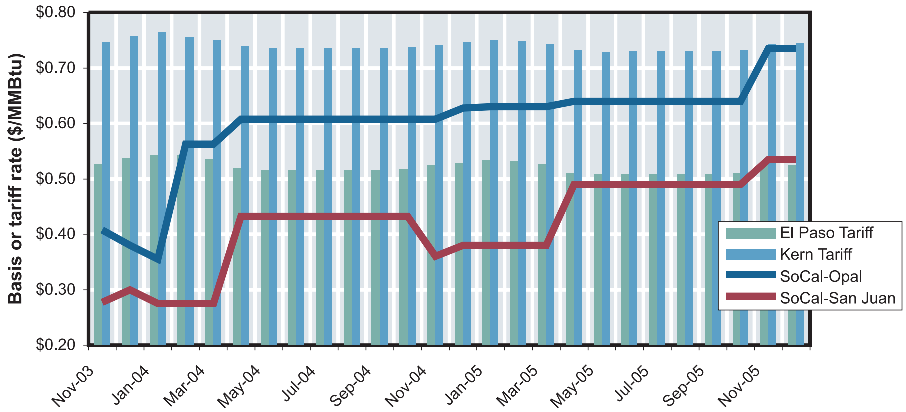
Substantial natural gas pipeline infrastructure was certificated during the assessment period, primarily to meet the needs of power generators. As shown in Figure 65, pipeline companies' investment plans are demonstrated by the 2,234 miles of pipeline (capacity of 7.4 Bcfd with an estimated cost of $4.6 billion) certificated by the Commission during the assessment period. Though this represents a significant level of new investment, it is a decline from 2001, when 3,044 miles of pipeline (9.5 Bcfd with an estimated cost of $5 billion) were certificated.

Several major pipelines that expanded service or came on line as greenfield systems during the assessment period had power generation "anchor" shippers. For example, power generation shippers accounted for nearly 86 percent (or 3.6 Bcfd out of 4.2 Bcfd) of capacity subscribed on a firm basis in a sample of pipeline certification applications approved by FERC since 2001 (identified in Figure 66).[195]

Nevertheless, certificated projects will only go forward if they secure the support of buyers, can be justified by market signals, can be financed and receive federal, state and local regulatory approvals. Before market participants contractually commit to a project, forward market basis values or swaps along key pipeline corridors need to signal that added capacity is needed and likely to be profitable. For instance, even with the Kern River capacity expansion, financial basis differentials in the Rockies continue to justify new pipeline construction within the next two years, as shown in Figure 67. Similarly, other western locations, such as the San Juan Basin, demonstrate basis differentials that would justify investment. The following chart shows the settlement values of the basis differentials for SoCal to both San Juan and Opal as compared to the Kern and

[195] OMOI has not attempted to estimate interruptible transportation usage on pipeline systems that have recently been expanded or built.

Figure 67: New Rockies investment still justified by basis differentials.



Source: Nymex ClearPort, pipeline tariffs, October 2003. Analysis and graphic by OMOI.

El Paso tariff rates for firm transportation. The convergence of the basis and tariff values for SoCal-Kern/Opal and SoCal-El Paso (San Juan) by the end of 2005 tends to support investment in new pipeline construction.

Another indicator of the forward market's role in signaling the need for infrastructure development can be seen in basis trading. The projected basis differential between Henry Hub and Transco Zone 6-NY, seen in Nymex's ClearPort activity for October 2003 settlements, indicates that the average market value of pipeline capacity from the Gulf Coast is comparable to the tariff rate plus fuel for Transco, the low cost carrier from the Gulf Coast (see Figure 68). This differential indicates some firm market valuation, but does not fully support new construction, which would be more costly than the existing firm transportation on Transco.

Despite considerable investment in new capacity during the assessment period, the pace of new investments slowed in comparison to prior periods, as evidenced by levels of certificated pipelines. In addition, this slowdown is also seen in delayed or cancelled projects, such as Independence and the related Supply Link. Approximately 6.1 Bcfd of major pipeline expansion projects have been delayed and cancelled since 2001. Reduced expectations for incremental projects to serve power generation, the slowing of the economy, a lack of long-term contractual support by financially distressed marketers, environmental concerns and competition from other recently completed projects all were likely contributors to the slower pace of new additions.

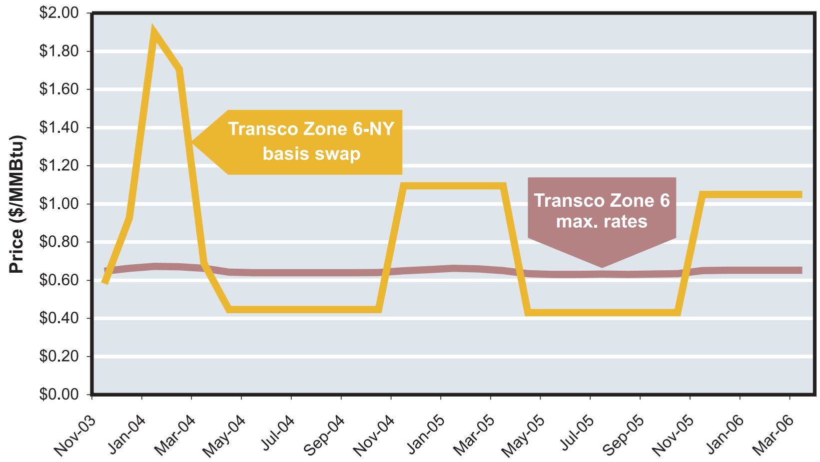
Market factors made it more difficult for shippers to contract for pipeline capacity. Gas-fired generators, faced with difficulties in executing long-term purchased power agreements and low average spark spreads for off-peak and peak periods, were unable to generate the cash flows needed to contract for the long term, firm natural gas transportation rights needed to anchor new investment in pipelines. The counterparty credit exposure to pipelines from capacity buyers who were under financial stress and had poor credit ratings continued to evolve during the assessment period. While traditional natural gas distribution customers typically have strong credit, the weakened status of marketing and generation companies raised concerns. Many wholesale marketers and merchant power producers no longer had the credit to make long-term financial commitments. During the assessment period, only six of the 23 merchant companies that Standard and Poor's rates had stable outlooks, and the rating agency does not foresee much improvement for the companies.[196]

The decline in shipper credit ratings led pipelines to strengthen credit terms.[197] During the assessment period, the Commission's natural gas pipeline credit policy provided a standard of security to the pipelines, for non-creditworthy customers, equal to three months demand charges. This is comparable to the time required to shut-in a non-paying customer, thus minimizing any pipeline exposure to uncollectible receivables. The credit requirements are up to 12 months pre-payment of demand charges for new pipelines, generally to satisfy lenders' requirements for financing new construction.

196 Standard & Poor's, "Refinancing Needs and Poor Credit Still Challenges the Energy Merchant Sector," www.riskcenter.com, Oct. 27, 2003.

197 Including Docket Nos. GT02-35-00, GT02-38-00, RP03-7-000, RP03-64-000, RP03-70-000, RP03-162-000 and RP02-363-003.

Figure 68: Projected Henry Hub to Transco Zone 6-NY basis does not support new construction.



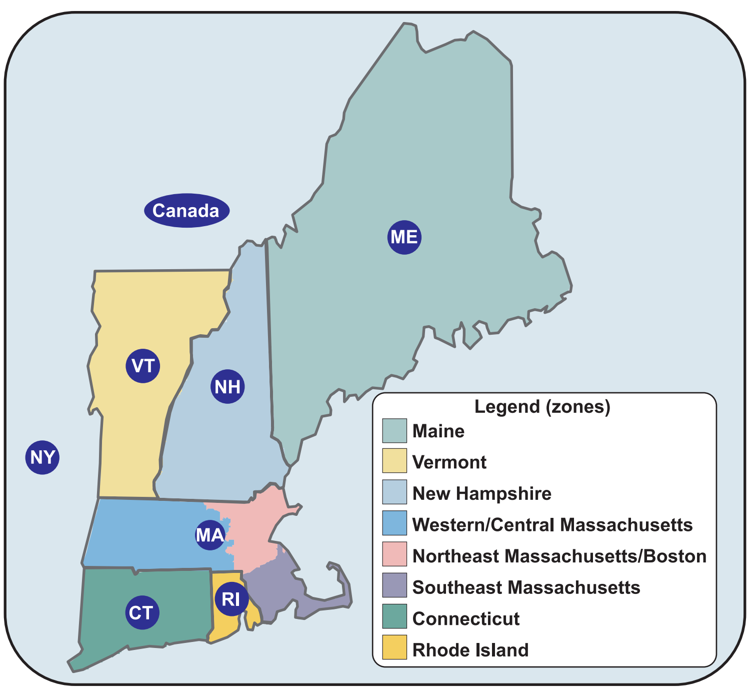
Source: Nymex ClearPort, October 2003. Analysis and graphic by OMOI.

Summary of Natural Gas Market Performance

Based on the analysis detailed above, we conclude that natural gas markets performed relatively well in that they continued to deliver product to customers despite supply tightness. In addition, investment levels appeared reasonable given market signals and conditions. Nevertheless, the increase in price and volatility levels observed in the assessment period strained some buyers and, if sustained, could have longer-term adverse economic effects. Further progress in the future on issues of price transparency, liquidity and forward market development needs to continue.

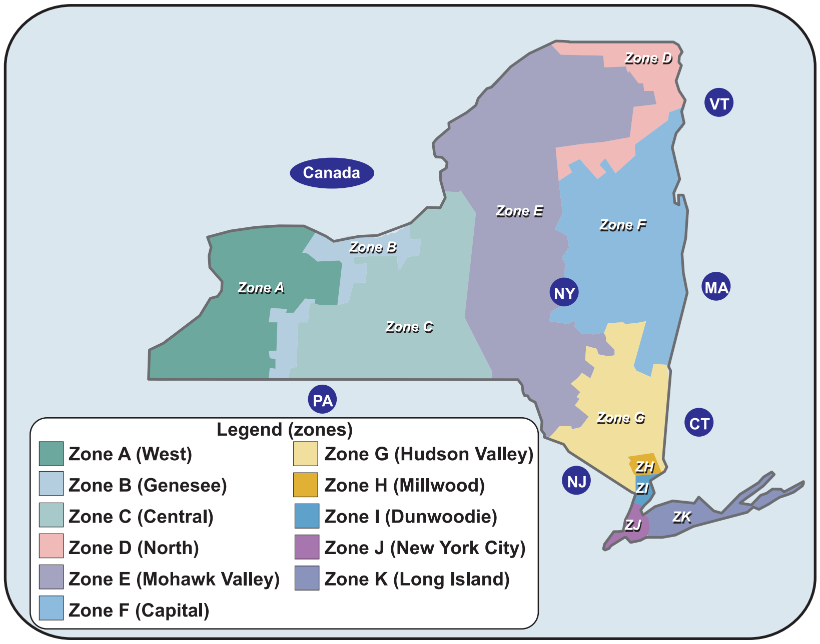
Appendix 1: Regional Maps

Figure 69: Map of ISO-NE.



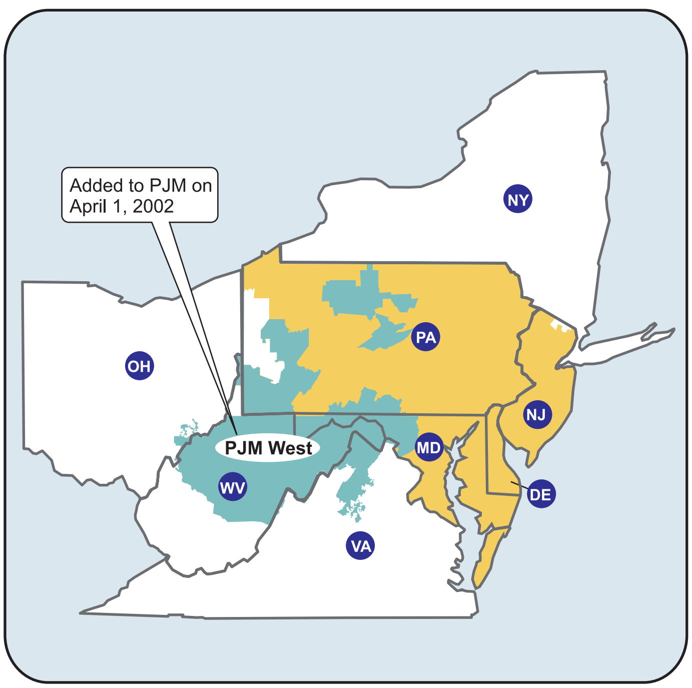
Source: Platts POWERmap. Graphic by OMOI.

Figure 70: Map of NYISO.



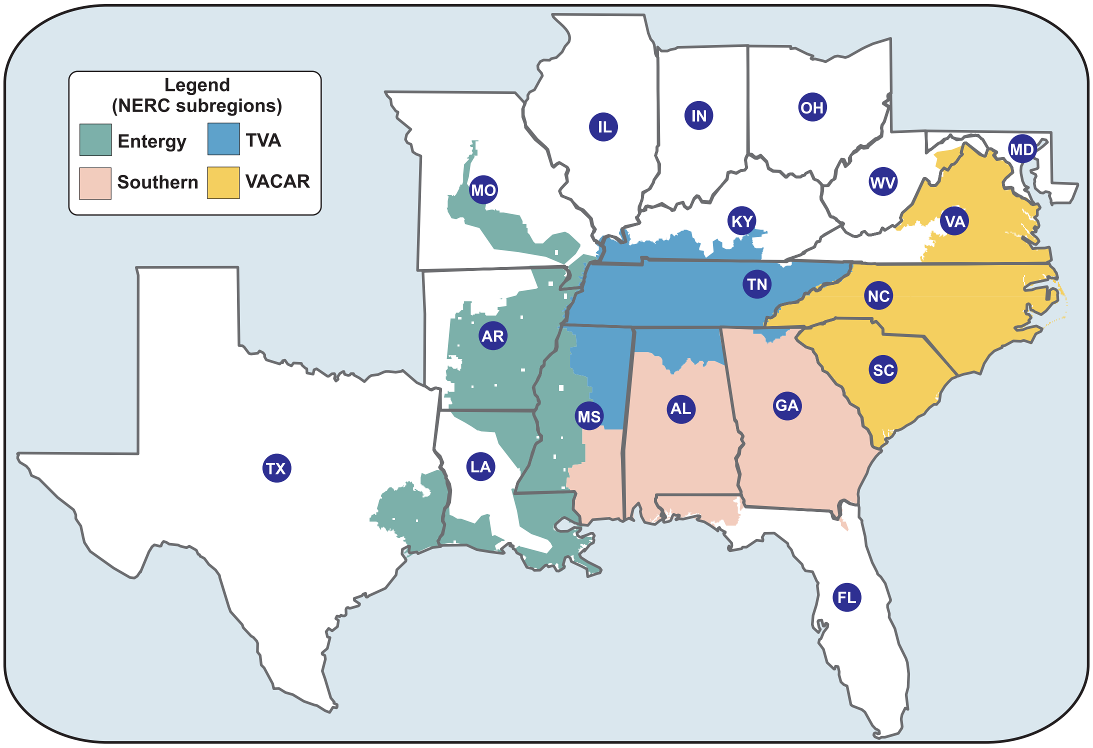
Source: Platts POWERmap. Graphic by OMOI.

Figure 71: Map of PJM.



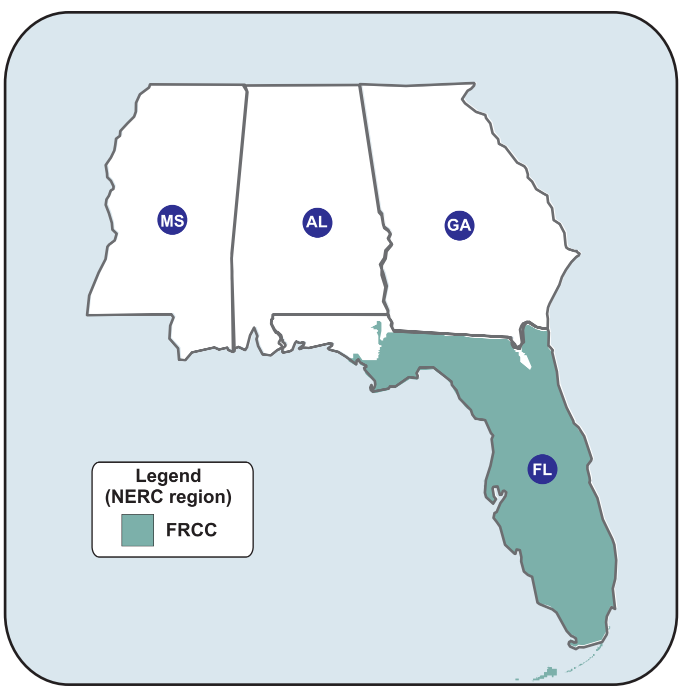
Source: Platts POWERmap. Graphic by OMOI.

Figure 72: Map of the Southeast.



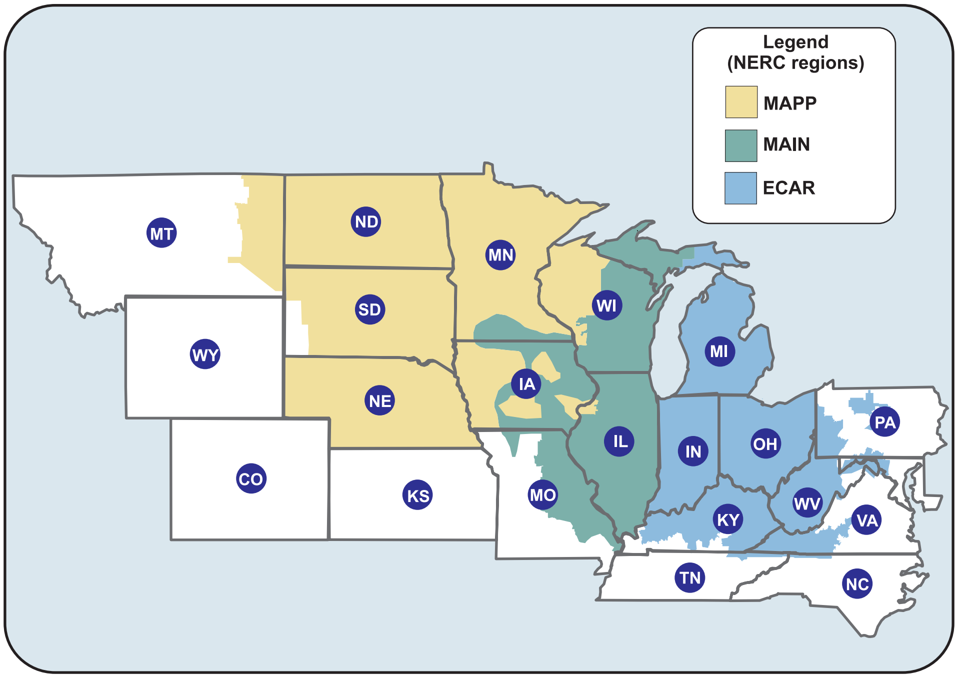
Source: Platts POWERmap. Graphic by OMOI.

Figure 73: Map of Florida.



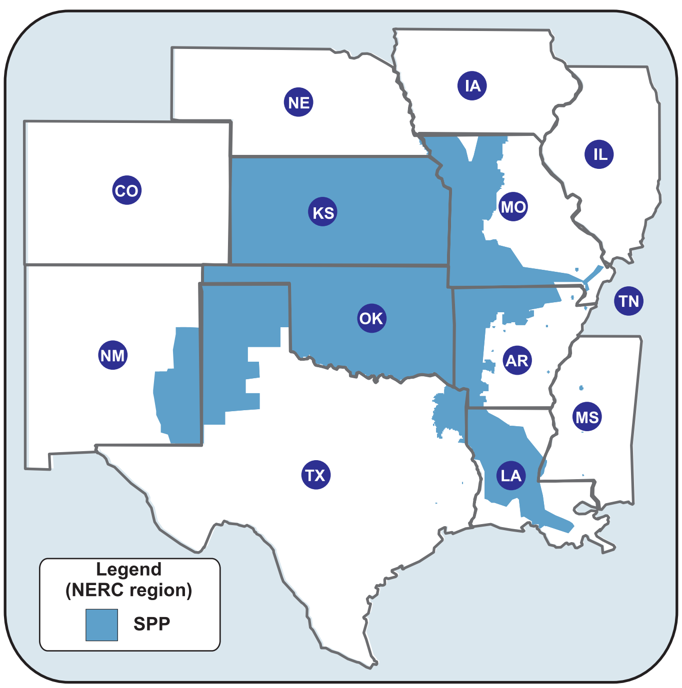
Source: Platts POWERmap. Graphic by OMOI.

Figure 74: Map of the Midwest.



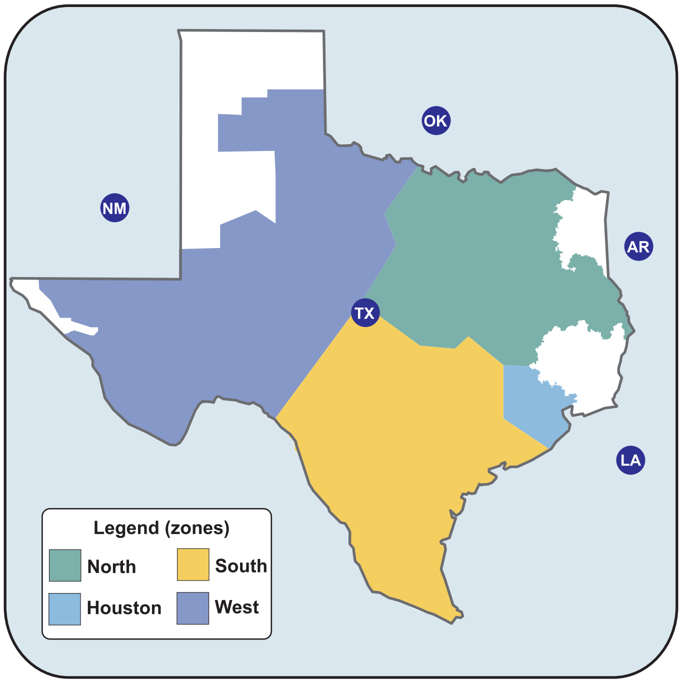
Source: Platts POWERmap. Graphic by OMOI.

Figure 75: Map of South Central.



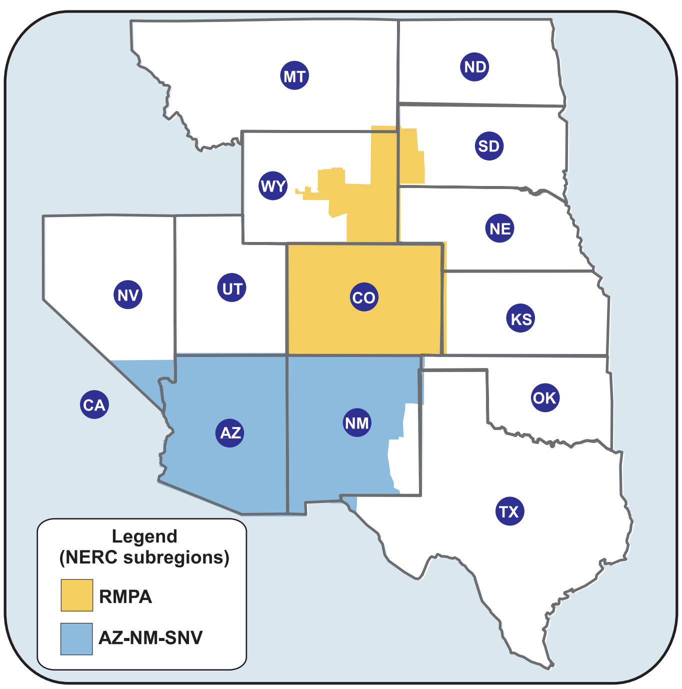
Source: Platts POWERmap. Graphic by OMOI.

Figure 76: Map of ERCOT.



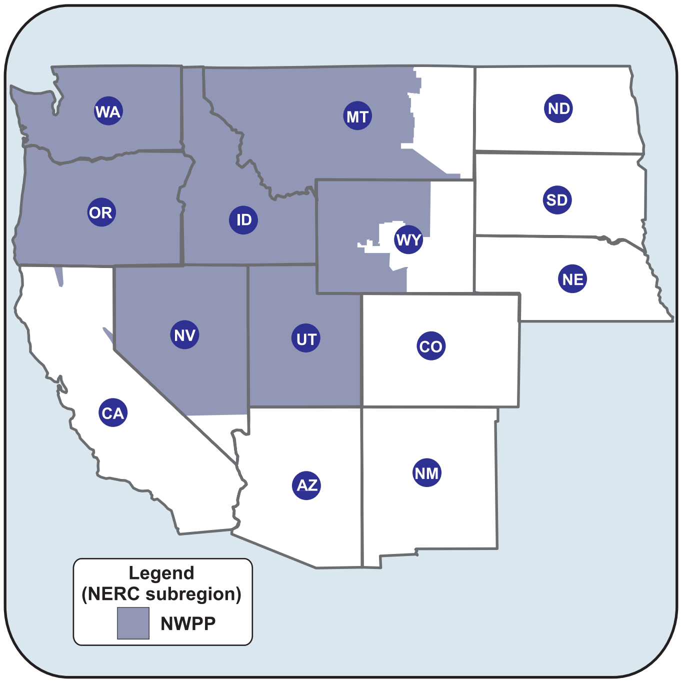
Source: Platts POWERmap. Graphic by OMOI.

Figure 77: Map of the Southwest.



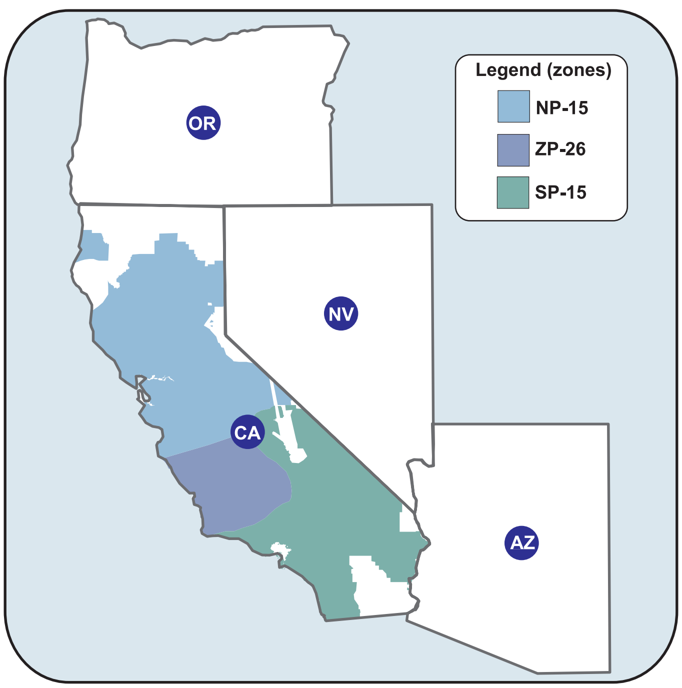
Source: Platts POWERmap. Graphic by OMOI.

Figure 78: Map of the Northwest.



Source: Platts POWERmap. Graphic by OMOI.

Figure 79: Map of CAISO.



Source: Platts POWERmap. Graphic by OMOI.

Appendix 2: Generating Capacity Additions

Table 22: Generating capacity additions and reserve margins.

Region	Capacity additions (MW)	Regional capacity percent increase	Regional increase as a percent of total U.S. additions	2002 reserve margin
ISO-NE	4,159	14.4%	4.9%	17%
NYISO	316	0.9%	0.4%	17%
PJM	7,458	8.8%	8.8%	13%
ERCOT	8,874	10.1%	10.4%	31%
CAISO	5,726	10.5%	6.7%	33%
Southeast	25,728	14.1%	30.3%	15%
Florida	4,466	10.4%	5.3%	20%
Midwest	14,471	7.8%	17.0%	28%
South Central	3,749	8.5%	4.4%	21%
Southwest	7,103	22.7%	8.4%	13%
Northwest	2,918	4.5%	3.4%	40%
Total	**84,967**	**10.1%**	**100.0%**	

Source: New capacity data derived from Energy Information Administration, Form EIA-860, "Annual Electric Generator Report." Regional Baseline capacity for percentage increase calculation as of Dec. 31, 2001. Reserve margin data from FERC; NERC ES&D Database; NERC 2002 Summer Assessment; NERC 2003 Summer Assessment, Summary of Estimated Loads and Resources; Western Electricity Coordinating Council, July 2003; ISO-NE website; PJM website; NYISO Load & Capacity Outlook, March 2002 and observed peak demand July 29, 2002. Appendix 3: Generation Ownership Concentration in Regional Electricity Markets

Appendix 3:

Generation Ownership Concentration in Regional Electricity Markets

Figure 80–Figure 96: Note: Installed capacity is the measured capacity or the capacity demonstrated to have been available during the hour of highest output of a generating unit. For purposes of this analysis, the working definition of a peaking unit is a natural gas or oil-fired unit with a heat rate greater than 10,000 Btu/kWh or a combustion turbine or internal combustion unit smaller than 50 MW in size with no reliable heat rate information reported. MWh produced is the net generation of an electric generating unit, or the amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries. Electricity required for pumping at pumped-storage plants is regarded as electricity for station service and is deducted from gross generation. Source: Platts POWERdat, Modeled Production Costs-Ownership-Based dataset for calendar year 2002. Analysis and graphics by OMOI.

A. Regions with organized markets

Figure 80: Generation ownership concentration in ISO-NE.

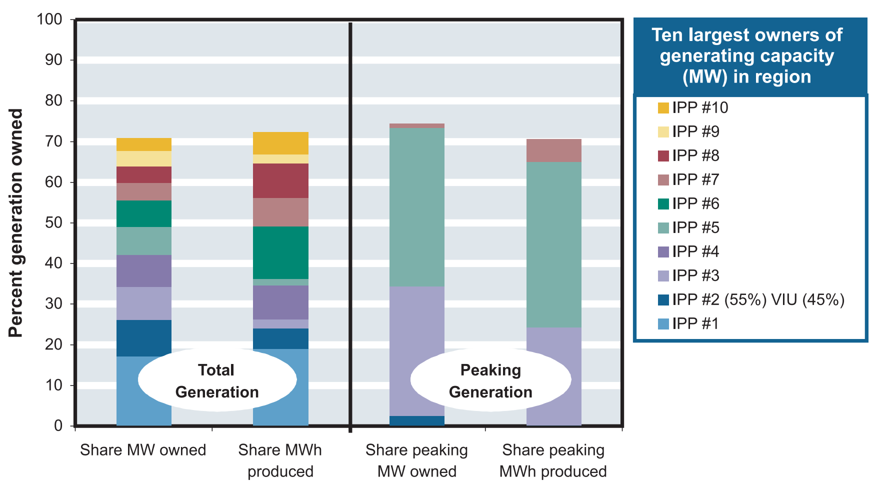


Figure 81: Generation ownership concentration in NYISO.

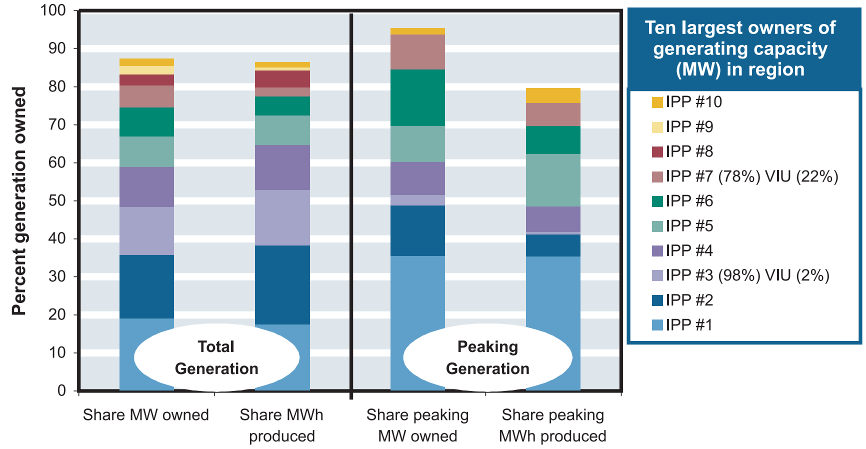


Figure 82: Generation ownership concentration in PJM.

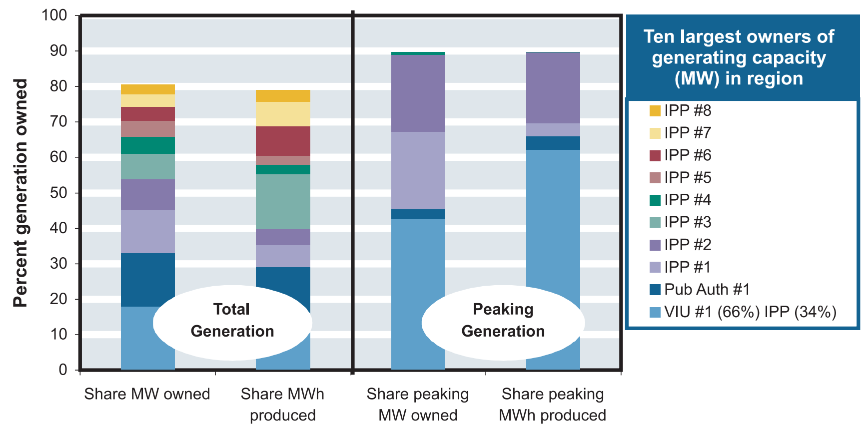


Figure 83: Generation ownership concentration in ERCOT.

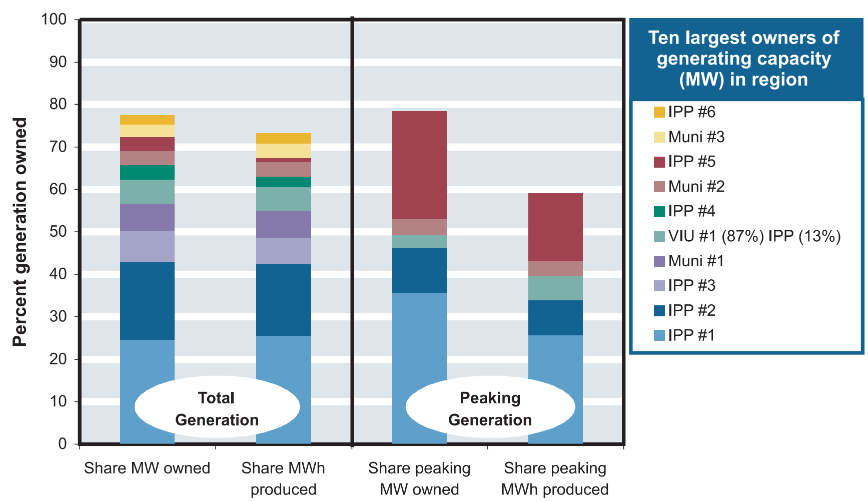
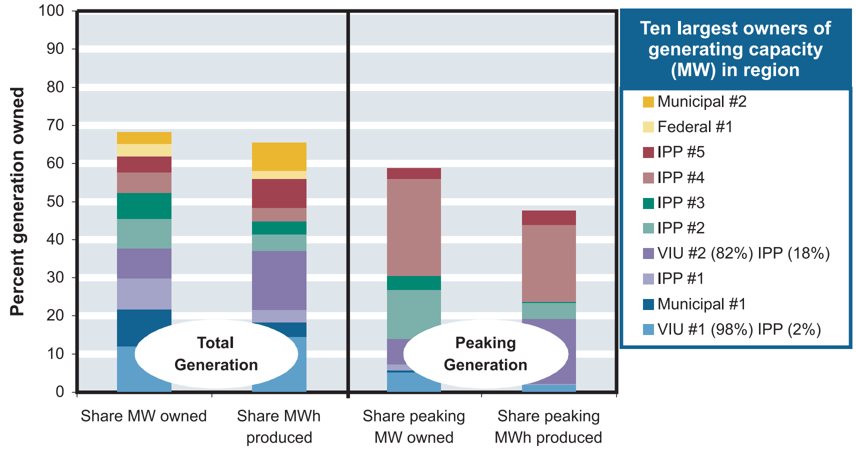


Figure 84: Generation ownership concentration in CAISO.



B. Regions without organized markets

Figure 85: Generation ownership concentration in the Southeast (Southern).

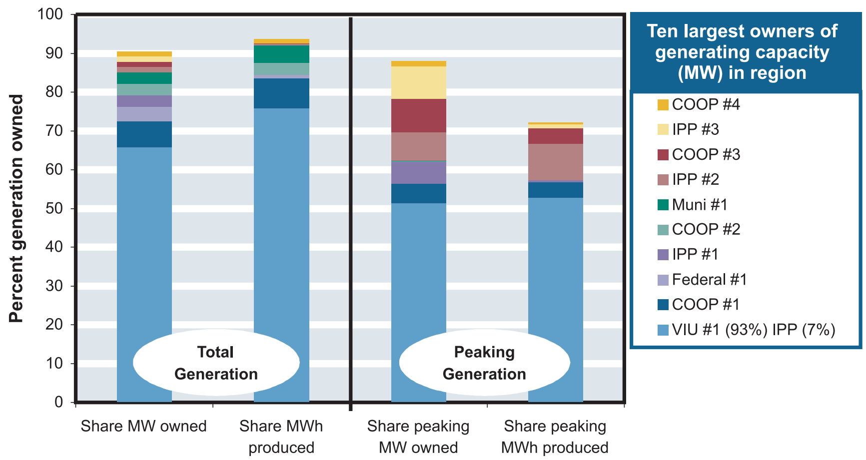


Figure 86: Generation ownership concentration in the Southeast (Entergy).

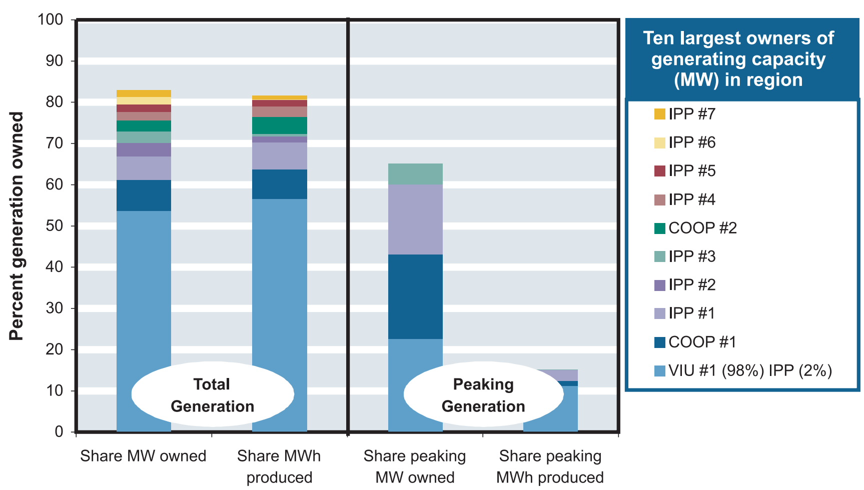


Figure 87: Generation ownership concentration in the Southeast (VACAR).

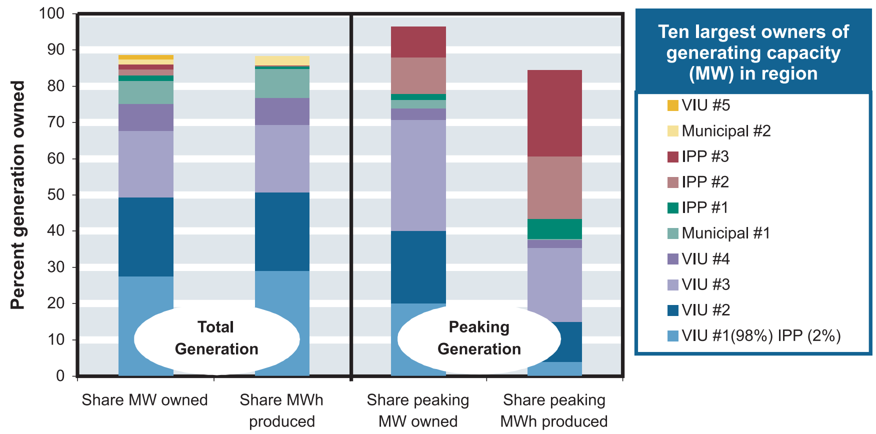


Figure 88: Generation ownership concentration in the Southeast (TVA).

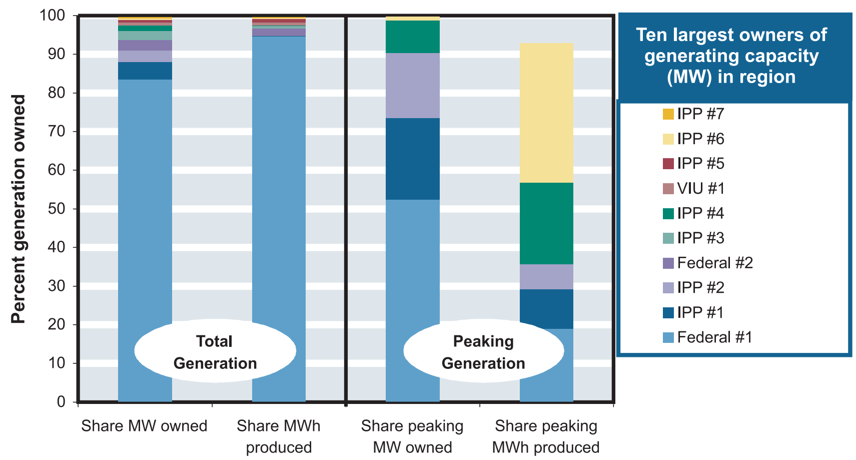


Figure 89: Generation ownership concentration in Florida (FRCC).

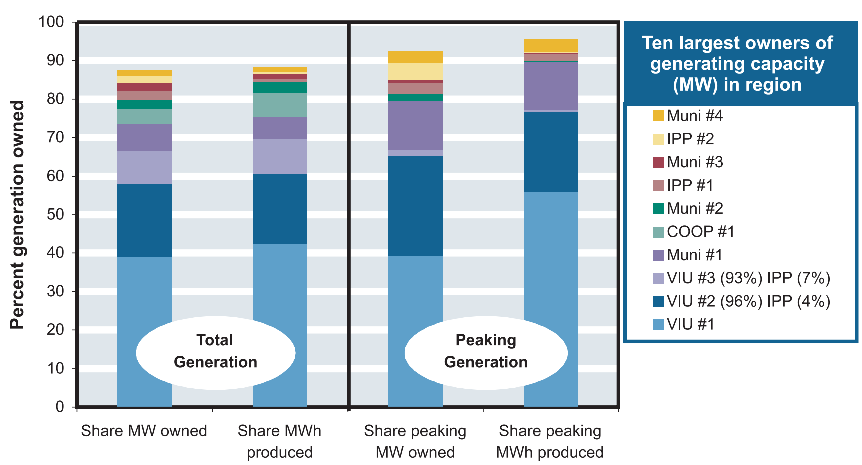


Figure 90: Generation ownership concentration in the Midwest (ECAR).

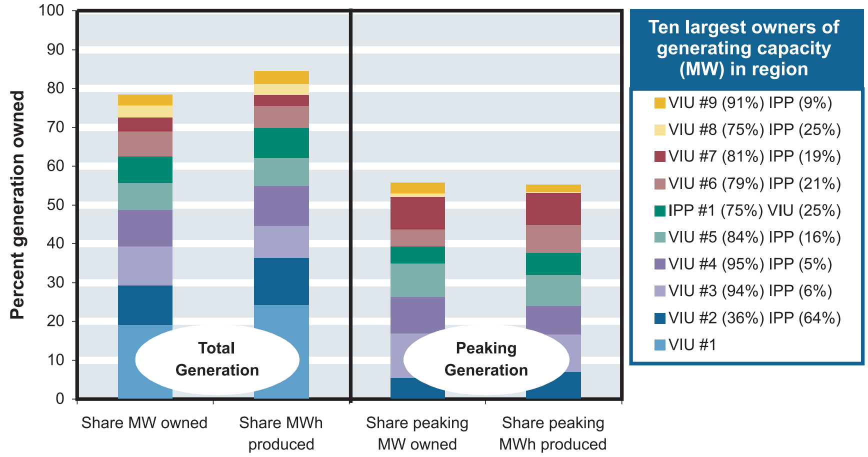


Figure 91: Generation ownership concentration in the Midwest (MAIN).

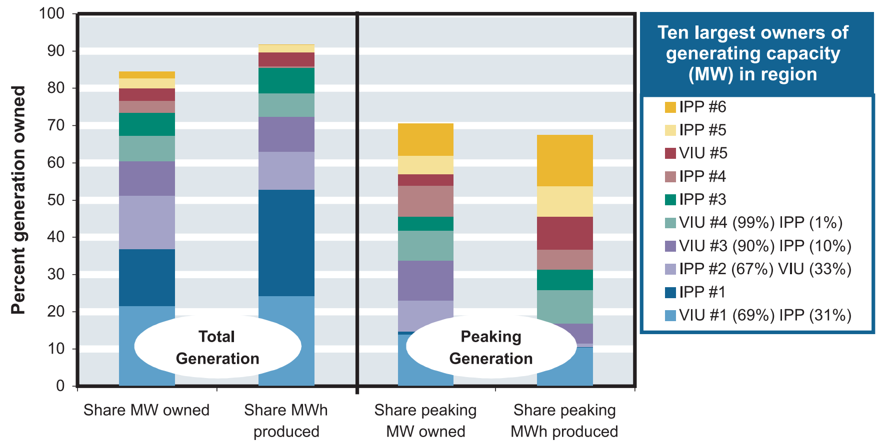


Figure 92: Generation ownership concentration in the Midwest (MAPP).

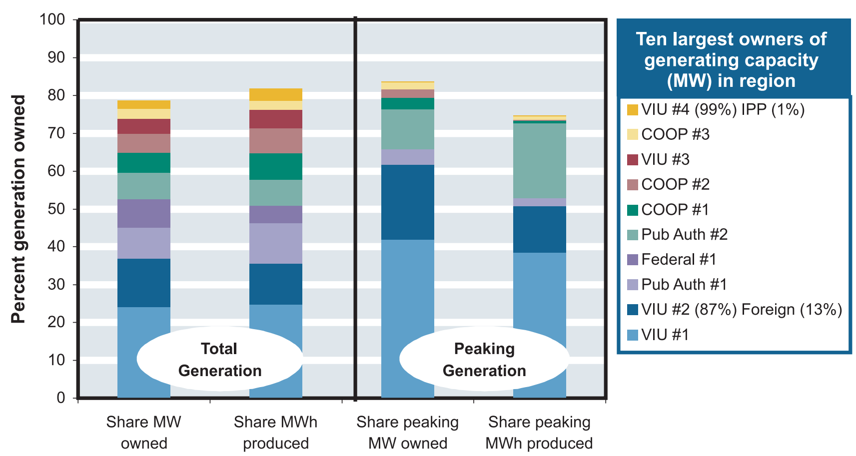


Figure 93: Generation ownership concentration in South Central (SPP).

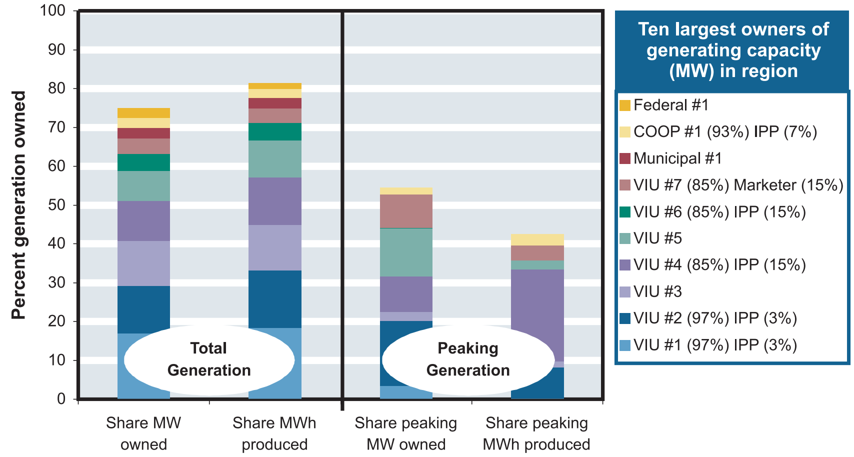


Figure 94: Generation ownership concentration in the Southwest (RMPA).

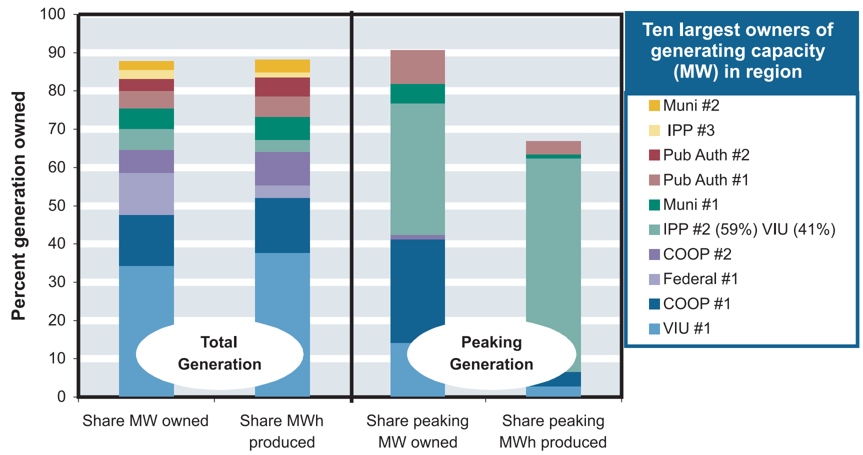


Figure 95: Generation ownership concentration in the Southwest (AZ-NM-SNV).

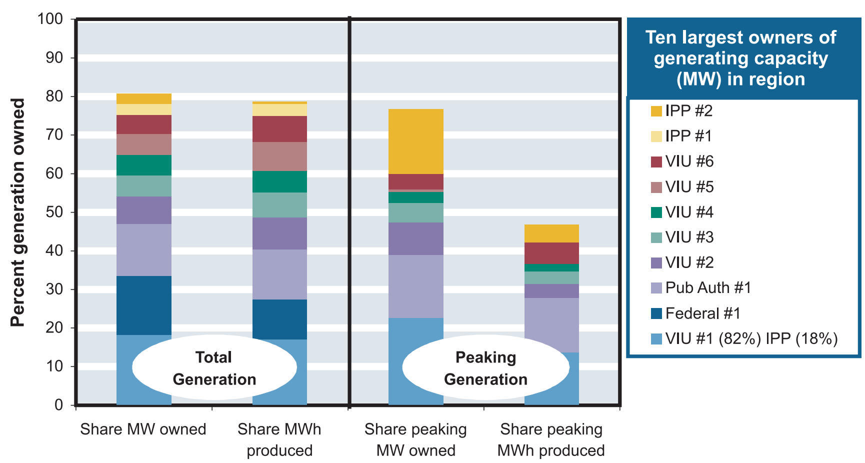
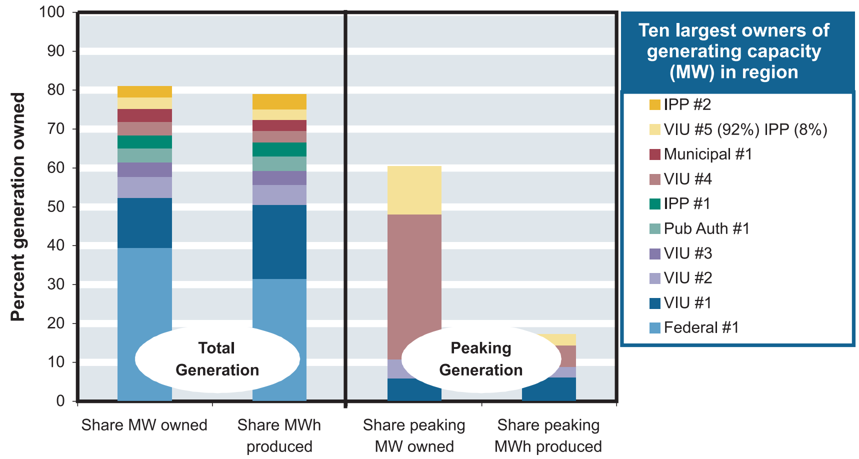


Figure 96: Generation ownership concentration in the Northwest (NWPP).



Appendix 4: Description of Natural Gas Markets and Products

The North American natural gas market is an integrated system of geographic markets that provides physical, financial and transportation products.

Physical products are defined by the geographic point of origin or the delivery points, typically market centers and hubs on the transportation system, where gas volumes are metered and other services are provided. The most well known geographic point for defining a product is the Henry Hub, the longest operating physical hub in the United States. Physical products are also delineated by the term of delivery—daily (spot), monthly, mid-term (*e.g.*, for the next winter or summer season).

Pipeline products enable a purchaser of physical gas to transport the product to the desired destination. ***Firm transportation***, the primary market service under which gas moves to market, provides for guaranteed delivery of gas in all events short of *force majeure*. Customers that can switch quickly to alternative fuels such as fuel oil (*e.g.*, commercial, industrial and power generators) usually opt for ***interruptible gas transportation***, which is subject to peremptory flow suspensions to make way for gas flowing under firm contracts.

Firm transportation customers can resell their capacity to other shippers, in the *secondary market*. The most common secondary market transactions are capacity release, transactions that enable firm shippers to let others use their capacity rights for a fee. The secondary market allows primary capacity holders to recoup at least some of the investment they have in capacity contracts and thereby offset the cost of reserving year-round capacity that they may not fully use. And it allows participants who have not made firm commitments to obtain capacity, sometimes at discounts or at least without long-term obligations. If the seller bundles the transportation service with physical product, the transaction may be considered "**gray market**," *i.e.*, the transportation cost is not transparent in a bundled transaction.

Financial derivative products complement the physical products by enhancing market flexibility, providing participants opportunities to manage risks associated with the ownership of the physical commodity and to participate in the market for speculative purposes. Natural gas financial products include futures, options and swaps. Financial derivative products, like physical products, are defined by geographic delivery location, usually Henry Hub, prices tied to that location and term (balance of the month, next month, a series of months or yearly).

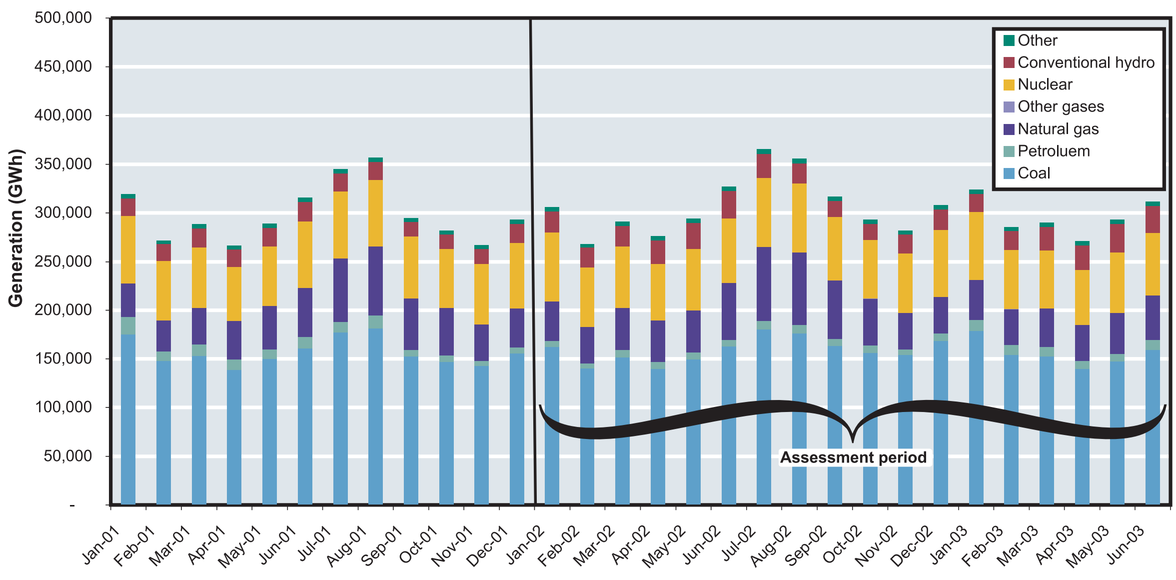
Financial products, most notably the New York Mercantile Exchange (Nymex) futures contract, provides a source of price discovery to the market. The Nymex contract trades forward futures for six consecutive years and provides a benchmark price within many physical and financial contracts. For instance, Nymex natural gas futures contracts and over-the-counter (OTC) basis swaps allow for the hedging of both commodity price risk and also basis or the imputed value of pipeline capacity. Other financial instruments such as options allow guaranteed prices even for uncertain volume requirements.

In addition to futures, options and swaps on Nymex, which is a regulated exchange, there is an OTC market for natural gas financial products. Activity on the OTC market is executed primarily through IntercontinentalExchange (ICE, an internet trading platform), voice brokers and direct bilateral transactions.

Appendix 5:

Electric Power Fuel Consumption Trends

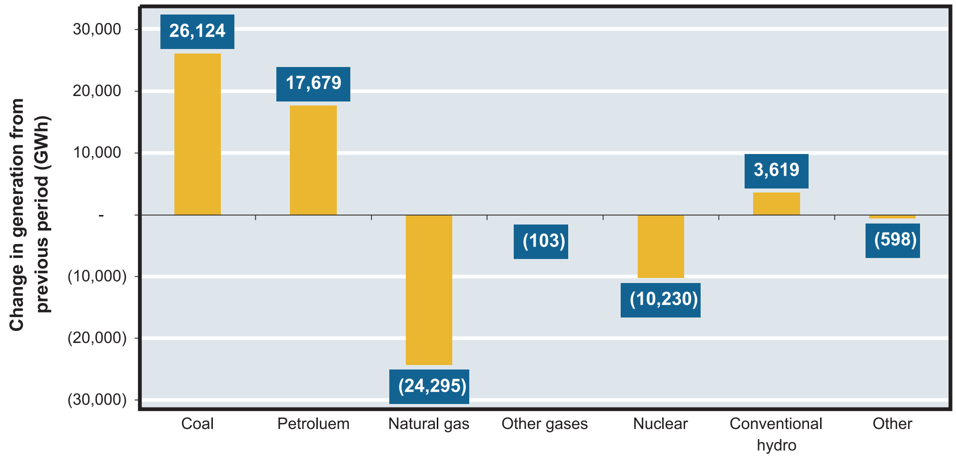
Figure 97: Overall electricity generation variable but continues to rise.



Note: Excludes pumped storage hydro.

Source: Monthly Energy Review, Table 7.2b, EIA, November 2003. Analysis and graphic by OMOI.

Figure 98: Recent increases in coal and petroleum fuel use offset declines in gas use.

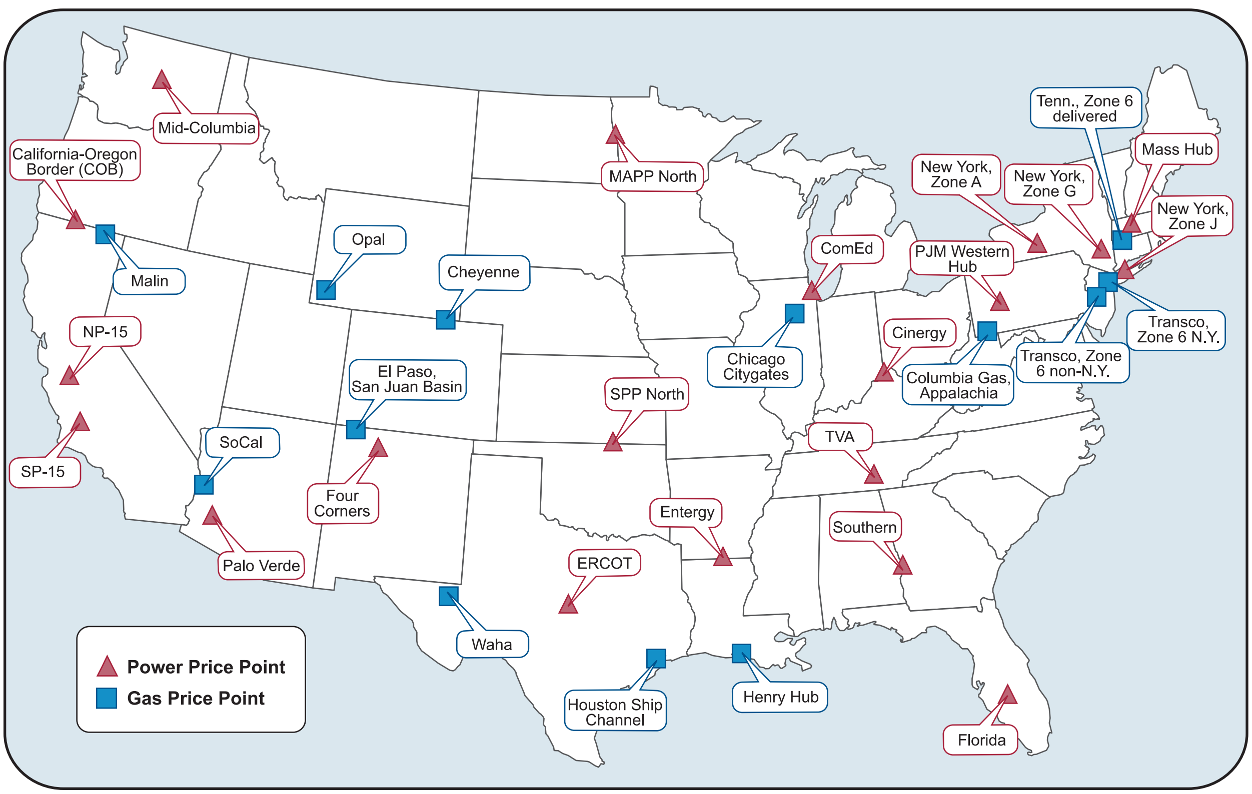


Notes: Comparison of January 2002–June 2002 and January 2003–June 2003. Excludes pumped storage hydro.
Source: Derived from Monthly Energy Review, Table 7.2b, EIA, November 2003. Analysis and graphic by OMOI.

As shown in Figure 97, overall electricity generation increased about 0.7 percent between the first six months of 2002 and the first six months of 2003 even though the composition of fuels consumed changed substantially. A 2.9 percent increase in coal generation (26,124 million kWh) and a 45 percent increase in petroleum generation (17,769 million kWh) offset percentage decreases in generation sourced by natural gas (9 percent or 24,295 million kWh) and nuclear (2.7 percent or 10,230 million kWh) as shown in Figure 98. Fuel switching from oil to gas explains part of the decline in gas-fired generation during the first half of 2003 compared to 2002 and increased generation by coal units and other fundamental factors (especially cooler weather) also explain the relative decline.

Appendix 6: Gas and Electric Price Points

Figure 99: Approximate locations of gas and electric price points.



Source: Platts POWERmap. Analysis and graphic by OMOI.

Appendix 7: List of Acronyms and Abbreviations

AEP	American Electric Power
AMP	Automated mitigation procedures
ARR	Auction revenue rights
ATC	Available transfer capability
AZ-NM-SNV	Arizona-New Mexico-Southern Nevada (NERC subregion)
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
Btu	British thermal unit
CAISO	California ISO
CA-MX	California-Mexico (NERC subregion)
CC	Combined cycle
CCRO	Committee of Chief Risk Officers
CERA	Cambridge Energy Research Associates
CERS	California Energy Resources Scheduling
CFTC	Commodity Futures Trading Commission
COB	California-Oregon Border
COOP	Cooperative
CT	Combustion turbine
DA	Day-ahead
DCA	Designated congestion area
DEC	Decremental (energy)
DOE	Department of Energy
DPL	Delmarva Peninsula
ECAR	East Central Area Reliability Coordination Agreement (NERC region)
EFP	Exchange of futures for physical
EFS	Exchange of futures for swaps
EIA	Energy Information Administration
EQR	Electric Quarterly Report
ERCOT	Electric Reliability Council of Texas (NERC region)
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council (NERC region)
FTR	Financial transmission right
GISB	Gas Industry Standards Board
GW	Gigawatt (one billion watts)
GWh	Gigawatt-hour (one billion watt-hours)
ICAP	Installed capacity
ICE	IntercontinentalExchange
INC	Incremental (energy)
INP	Indian Point (nuclear plant in NYISO)
IPP	Independent power producer

ISDA	International Swap Dealers Association
ISO	Independent system operator
ISO-NE	ISO New England
JOA	Joint operating agreement
kWh	Kilowatt-hour (one thousand watt-hours)
LBMP	Locational-based marginal price
LDC	Local distribution company
LIPA	Long Island Power Authority
LMP	Locational marginal price
LNG	Liquefied natural gas
LSE	Load serving entity
MAAC	Mid-Atlantic Area Council (NERC region, geographically within PJM)
MAIN	Mid-America Interconnected Network (NERC region)
MAPP	Mid-Continent Area Power Pool (NERC region)
MISO	Midwest Independent Transmission System Operator
MMBtu	Million British thermal units
MMG	Market Monitoring Group (in ISO-NE)
MMU	Market monitoring unit
MW	Megawatt (one million watts)
MWh	Megawatt-hour (one million watt-hours)
NAESB	North American Energy Standards Board
NEMA	Northeast Massachusetts
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NGX	Natural Gas Exchange (in Canada)
NP-15	North of Path 15 (in CAISO)
NPC	National Petroleum Council
NPCC	Northeast Power Coordinating Council (NERC region, geographically includes ISO-NE and NYISO)
NWPP	Northwest Power Pool (NERC subregion)
NY	New York
NYC	New York City
NYISO	New York Independent System Operator
Nymex	New York Mercantile Exchange
NYPP	New York Power Pool
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and maintenance
OMOI	Office of Market Oversight and Investigations (FERC)
OOM	Out of market
OOS	Out of sequence
OTC	Over the counter
PG&E	Pacific Gas & Electric
PJM	PJM Interconnection
PUSH	Peaking Unit Safe Harbor
PX	Power Exchange (formerly in CAISO)
RMPA	Rocky Mountain Power Area (NERC subregion)
RMR	Reliability must run
RSI	Residual supply index
RT	Real-time
RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission organization
RTS	Real-time scheduling
SCE	Southern California Edison
SERC	Southeastern Electric Reliability Council (NERC region, includes Entergy, Southern, TVA and VACAR)
SoCal	Southern California
SP-15	South of Path 15 (in CAISO)
SPP	Southwest Power Pool (NERC region)
SWCT	Southwest Connecticut
TLR	Transmission loading relief
Transco	Transcontinental Gas Pipe Line
TVA	Tennessee Valley Authority (NERC subregion)
VACAR	Virginia-Carolinas area (NERC subregion)
VAP	Dominion-Virginia Power
VIU	Vertically integrated utility
VRD	Virtual regional dispatch
WECC	Western Electricity Coordinating Council (NERC Region)
WUMS	Wisconsin-Upper Michigan subregion
ZP-26	Zone at Path 26 (in CAISO)

Appendix 8: GLOSSARY

12-month strip: Prices for the next 12 months of consecutive natural gas futures trading contracts, usually starting with the nearest, or prompt, month.

Ancillary services: Those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. Ancillary services supplied with generation include: load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services and energy imbalance services.

Arbitrage: The simultaneous purchase of a commodity/derivative in one market and the sale of the same, or similar, commodity/derivative in another market in order to exploit price differentials.

Assessment period: The time period between Jan. 1, 2002 and June 30, 2003 for the purposes of this report.

Auction Revenue Right: An ARR entitles its holder to receive a share of revenues from the auction of a corresponding financial transmission right (FTR).

Automatic generation control: The automatic regulation of the power output of electric generators within a prescribed range in response to a change in system frequency, or tie-line loading, to maintain system frequency or scheduled interchange with other areas within predetermined limits.

Automated mitigation control: A procedure under which the bids of individual suppliers would be capped under certain pre-determined conditions. As implemented in New York, this procedure is triggered when the locational marginal price exceeds $150/MWh. Individual bids are then subject to a conduct test and an impact test. The conduct test is failed if the bid exceeds a threshold based on a predetermined "reference bid." The impact test is failed if the change in the market-clearing price, using reference bids in place of actual bids, exceeds a certain threshold.

Balancing: The requirement imposed by electricity grids or natural gas pipelines that supply and demand be equal over a certain time period.

Baseload: The minimum amount of electric power delivered or required over a given period of time at a steady rate. The minimum continuous load or demand in a power system over a given period of time.

Baseline: In electric markets, baseline refers to an agreed-upon level of electricity consumption from which deviations are measured. Baselines are usually based on a customer's historical usage. The variation in usage from the baseline may be billed at a different rate.

Basis: The price difference between a natural gas price point (e.g., a market hub, citygate or supply receipt area) and a reference point, most often Henry Hub. Financial basis refers to the difference between the futures expiration price and the monthly cash price index at Henry Hub or at another geographical point.

Bid-ask differential: The difference in price between what a buyer offers to pay for a commodity and what a seller offers to accept for a commodity.

Bilateral physical electricity transaction: A direct contract between an electric power producer and either a user or broker outside of a centralized power pool or power exchange.

Bus: A conductor or group of conductors that serve as a common connection for two or more electric circuits within a station.

Capacity margin: The amount of capacity above planned peak system demand available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen demand.

Capacity markets: Markets designed to allow companies with an obligation to deliver electricity to customers to competitively procure contracts with power plant owners to have their units up and running and able to produce additional energy.

Clearing: The registration and settlement of a trade that includes provisions for margin requirement and performance guarantee.

Combined-cycle generators: Power generating units that increase the efficiency of electric generation by capturing and reusing waste heat; the latest units achieve heat rates near 6,000 Btu/kWh with more than 50 percent fuel-to-electricity conversion efficiency.

Congestion: A characteristic of the transmission system produced by a constraint on the optimum economic operation of the power system, such that the marginal price of energy to serve the next increment of load, exclusive of losses, at different locations on the transmission system is unequal.

Congestion costs: Charges assessed and redistributed due to electrical transmission network constraints.

Control area: An electric power system or combination of electric power systems to which a common automatic control scheme is applied in order to: (1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load in the electric power system(s); (2) maintain, within the limits of Good Utility Practice, scheduled interchange with other Control Areas; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Cooling degree days: A measure of cooling energy demand determined by how far a location's temperature averaged above 65 degrees Fahrenheit.

Credit clearing: A mechanism for settling mutual claims, the result of which is that the risk that a company might fail to fulfill its contract is pooled among many companies.

Credit rating: A statistical technique wherein several financial characteristics are combined to form a single score to represent a customer's creditworthiness.

Credit risk: The risk that an issuer of debt securities or a borrower may default on his obligations, or that the payment may not be made on a negotiable instrument.

Critical notices: Pipeline issuances that provide information on conditions that affect natural gas scheduling or adversely affect scheduled gas flow.

Curtailable load: Electricity deliveries that are subject to interruption by the grid operator.

Day-ahead markets: Forward markets for electricity or natural gas to be supplied the following day.

Debt financing: Providing the necessary capital by selling bonds, bills or notes to individuals or institutions.

Demand elasticity: The demand response, or lack thereof, of customers as a result of a change in price.

Demand responsiveness/demand response: A situation that occurs when customers respond to an increase in price, or a grid operator's call for emergency relief, by lowering demand for a good or service and respond to a decrease in price by increasing demand for a good or service.

Dispatch declines: The 16 categories for which a generator may decline a dispatch instruction in CAISO's automated dispatch system, e.g., safety, unit derating or environmental constraints. If an automated dispatch instruction is not responded to within two minutes, it is considered declined.

Dual-fueled (or dual-fired) unit: A generating unit that can produce electricity using two or more fuels.

In some of these units, only the primary fuel can be used continuously; the alternate fuel(s) can be used only as a start-up fuel or in emergencies.

Economic withholding: An exercise of market power intended to raise the market price above competitive levels by pricing offer blocks high enough to effectively “withhold” or reduce the quantity of supply that is offered at “competitive” prices.

Electronic trading platform: An electronic system that allows brokerages and individual traders to trade directly between themselves without having to go through a middleman.

Equity financing: Providing the necessary capital by selling common stock or preferred stock to investors.

Exchange: A marketplace in which shares, options and futures on stocks, bonds, commodities and indices are traded.

Financial liquidity: An entity’s ability to obtain funds to meet its cash flow obligations, with consideration for the speed with which such funds can be obtained.

Financial transmission right: A contract that entitles the holder to receive compensation (or pay) for certain transmission charges that arise when the grid is congested and differences in locational prices result from the redispatch of generators to relieve that congestion.

Firm transportation: Contracted energy deliveries that are guaranteed not to be interrupted.

Forward price curve: The chronological set of prices determined by a market for a good that will be delivered in the future.

Fuel-adjustment clause: A provision of a power sales agreement or rate schedule that allows for the electricity price to be changed based on changes in the price of the fuel used to generate the power.

Futures market: A market in which contracts for future delivery of a commodity are bought or sold.

Heating degree days: A measure of heating energy demand determined by how far a location’s temperature averaged below 65 degrees Fahrenheit.

Hedging: A risk management tool used to protect the value of an investment or contractual commitment from the risk of loss due to price fluctuations.

Hirschman-Herfindahl Index (HHI): Often used to evaluate mergers, the HHI is a commonly accepted measure of market concentration. It is calculated by squaring the market share of each firm competing in a market, and then summing the resulting numbers.

Hub: A geographical location where multiple participants trade services.

Independent market monitor: A party that monitors market operations for compliance with market rules and identifies flaws in market rules or other issues affecting market efficiency and market power abuses.

Independent system operator (ISO): An organization that has been granted the authority to operate, in a nondiscriminatory manner, the transmission assets of the participating transmission owners in a fixed geographic area. ISOs often run organized markets for spot electricity.

Injection season: The April 1 through Oct. 31 period, during which gas is injected into natural gas storage reservoirs in preparation for withdrawal and use during the winter heating season.

Interruptible or nonfirm transportation: Transmission service that is reserved and scheduled on an as-available basis and is subject to curtailment or interruption.

Intertie: The point of physical interconnection between adjacent transmission systems.

Load: Often synonymously used with demand, load is the total amount of power carried by an electric system at a point in time.

Load pocket: An area isolated by the limits of the transmission network to get power into the area; demand within the load pocket exceeds internal generation, so imports are needed or reliability will fail.

Load-serving entity (LSE): Any entity, including a load aggregator or power marketer, that serves end-users within a control area and has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the control area.

Locational marginal price: The market-clearing price for electricity at the location the energy is delivered or received.

Long position: The market position of a futures contract buyer whose purchase obligates him to accept delivery unless he liquidates his contract with an offsetting sale.

Loop flow: The fact that electricity flows on transmission lines in accord with the physical laws of electricity and not on the route contracted for by the seller. In some areas, system configuration is such that electricity flows in large cross-regional loops, as around the Great Lakes area of southern Canada.

Losses: Energy (kilowatt-hours) and power (kilowatts) lost in the operation of an electric system. Losses occur principally as waste heat in electrical conductors and apparatus such as transformers.

Margin requirement: The amount of money required to hold a contract and cover changes in the value of the contract.

Marginal electric generating unit: The last unit turned on in an area to serve load. In organized wholesale markets, the price of the marginal source of electricity usually sets the price for all generation within the market.

Mark-to-market: The process whereby the book value or collateral value of a security is adjusted to reflect current market value.

Market capitalization: A measure of company size that is computed as current market price per share of stock times the total number of shares outstanding.

Market liquidity: The ease, or lack thereof, with which a buyer can buy or a seller can sell at a prevailing price in a marketplace.

Market monitoring unit: An independent and objective overseer of organized power markets. The MMU evaluates and reports on the operation of the markets, including transmission congestion costs and the potential for a market participant to exercise undue market power.

Market participant: A market buyer or a market seller, or both, that meets reasonable creditworthiness standards established by the market operator.

Market power: A measure that can include, but is not limited to, the ability of a firm to raise its price or withhold its output with the effect of raising market prices above competitive levels for a sustained period of time.

Merchant generator: A generating plant built "on spec," with no energy sales contracts in place. Merchant plants compete in the deregulated market on their ability to generate low cost power and support the local grid system.

Mitigation: A process by which a market operator can deter market behavior that may interfere with the competitive and efficient operation of the markets when market participant conduct falls outside certain prescribed guidelines.

Native load: Wholesale and retail customers that the transmission provider has an obligation to serve.

Open access: 1) A term becoming generally applied to the evolving access to the transmission system for all generators and wholesale customers. (2) The use of utility's transmission and distribution facilities on a common-carrier basis at cost-based rates.

Over the counter (OTC): Named for what was once an informally organized market, the OTC is today a well organized market place although with little or no regulatory oversight in comparison to an exchange or customized derivatives traded outside of an organized exchange.

Peaking capacity: Generating equipment normally operated only during the hours of highest daily, weekly, or seasonal loads; this equipment is usually designed to meet the portion of load that is above base load.

Pivotal supplier: A power supplier whose capacity must be used to meet peak demand and whose capacity exceeds the market's supply margin.

Project financing: A form of asset-based financing in which a firm finances a discrete set of assets (the project) on a stand-alone basis.

Ramp rate: The rate at which you can increase load on a power plant. The ramp rate for a hydroelectric facility may be dependent on how rapidly water surface elevation on the river changes.

Real-time market: An electric market that determines the economic dispatch and establishes a market-clearing price for settlements for one-hour periods or less during the day of delivery.

Real-time pricing: A system that provides signals to customers on the value of consuming energy at the time of consumption.

Reference price: The settlement price of a derivatives contract, based on a particular location and commodity, or an estimated electricity price, based on a forecast of market conditions.

Regional transmission organization (RTO): An organization with some similar roles to an independent system operator (ISO) but covering a larger geographical scale and involved in both operation and planning of the transmission system. RTOs often run organized markets for spot electricity.

Reliability must run (RMR): A unit identified by the ISO as necessary for operational or reliability reasons and must run, regardless of economic considerations.

Reserve margin: The percentage of installed capacity exceeding the expected or actual peak demand during a specified period.

Residual Supply Index (RSI): Residual supply is the amount of generation capacity remaining in the market, after subtracting the capacity of the largest supplier. If RSI exceeds 100 percent, this indicates that the alternative suppliers have sufficient capacity to meet demand without the largest supplier, who is thus presumed to have relatively little influence on the market-clearing price for a given hour. However, if the RSI is below 100 percent, this indicates that the largest supplier's capacity is needed to meet market demand and the supplier is considered pivotal in determining the market-clearing price for that hour.

Retail unbundling: Disaggregating electric utility service into its basic functions and offering each component separately for sale with separate rates for each component. For example, generation, transmission and distribution could be unbundled and offered as discrete services.

Ring-fencing: Techniques used to isolate the credit risk of a subsidiary within a corporation from the risk of its affiliated companies.

Risk management: The process of analyzing exposure to risk and determining how to best handle such exposure.

Seams: Barriers and inefficiencies resulting from equipment limitations and differences in market rules and designs, operating and scheduling protocols and other control-area practices that inhibit or preclude the ability to transact capacity and energy between regions.

Short position: The market position of a futures contract seller whose sale obligates him to deliver the commodity unless he liquidates his contract by an offsetting purchase.

Single settlement system: A market structure that provides only a real-time market.

Spark spread: The cost difference of converting natural gas into electricity. It can also be the difference between gas and electricity futures prices. Marketers use the spark spread as an indicator of arbitrage opportunities.

Spot market: The natural gas market for contractual commitments that are short term (usually a month or less) and that begin in the near future (often the next day, or within days). In electricity, spot markets are markets for day-ahead and real-time electricity, sometimes run by an independent system operator or regional transmission organization.

Spread trading: Buying one instrument/commodity and selling another, with a view to profiting from the change in the gap between the two markets.

Swaps: An exchange of streams of payments over time according to specified terms. An example of a natural gas fixed-for-floating swap is to swap a fixed price for natural gas against a specified index price at a defined geographical point over a specified time period.

Time-of-use pricing: A rate design imposing higher charges to customers during periods of the day when higher demand and higher cost of production is experienced.

Tolling agreement: An agreement whereby a party moves fuel to a power generator and receives kilowatt hours (kWh) in return for pre-established fees.

Transaction costs: Costs incurred when buying or selling assets, such as commissions and the spread.

Transmission loading relief (TLR): A situation called when electricity flows exceed permitted levels; a TLR is called to preserve the reliability of the electric transmission system. A TLR interrupts specific transmission flows or transactions and may curtail service to specific customers or future transmission schedules.

Transparency: A measure of the extent to which a market's current trade and quote information is readily available to the public.

Two-settlement system: A system under which the price for electricity on any given day is established both on a day-ahead and a real time basis. Day-ahead prices are based on forecasted energy demand and transmission and generation availability. Real-time prices reflect not only the day-ahead anticipated events and unit schedules, but also what actually occurs in real time, such as generation or transmission outages, and changes in forecasted load.

Uplift: Uplift generally refers to costs allocated to all market participants in a given region or market and not charged directly to the participant that caused the cost to be incurred. Some categories of charges that may be allocated to uplift are ancillary services and out-of-merit dispatch costs.

Usage charge: A broad term which refers to charges levied on power suppliers or their customers for the use of the transmission or distribution wires.

Virtual bidding: A practice that allows participants to hedge against the risk that real-time and day-ahead prices will differ, or to speculate on the difference.

Voice broker: A trading intermediary matching buyers and sellers using the approach of telephone confirmation, versus an electronic trading platform.

Volatility: A measure of the price fluctuation of a commodity or financial instrument that takes place over a certain period of time.

Volumetric risk: The effect on revenue of fluctuations in demand for a product or service.

Wash trade: A prearranged pair of trades of the same good between the same parties, involving no economic risk and no net change in beneficial ownership.

Wholesale electricity markets: The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Winter heating season: The Nov. 1 through March 31 period, during which most natural gas use for space heating takes place.

Zonal price: A pricing mechanism for a specific zone within a control area.

Appendix 9:

List of Figures and Tables

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