

FEDERAL ENERGY REGULATORY COMMISSION

2006 STATE OF THE MARKETS REPORT

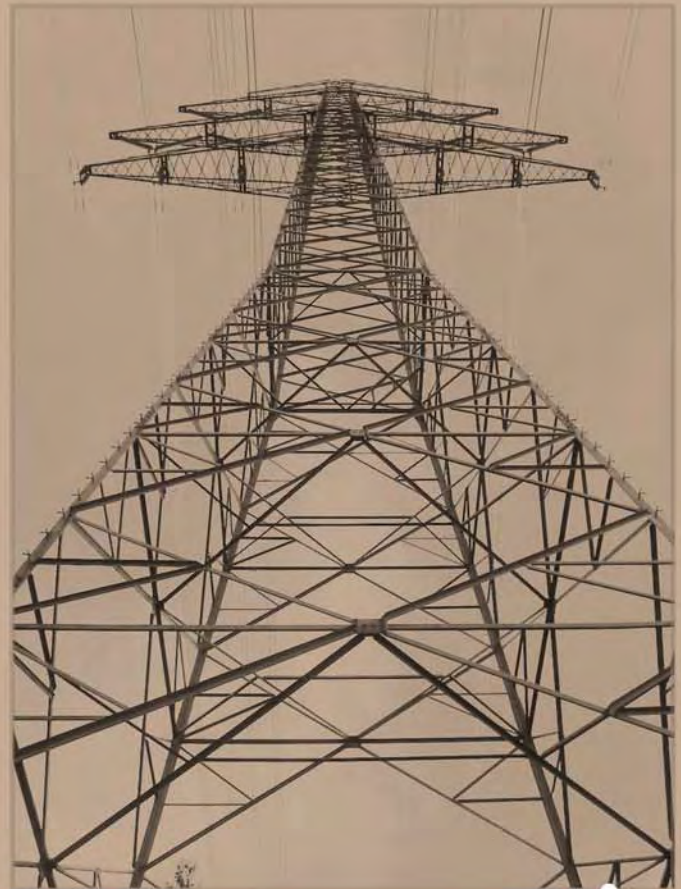
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First Street, N.E.
Washington, D.C.



2006 State of the Markets Report

EXECUTIVE SUMMARY

In 2005 and 2006, electric and natural gas markets in the United States proved sufficiently robust to successfully meet various supply- and demand-related challenges with no major failures of service.

While these markets continued to produce evidence of long-term developmental trends, the most striking forces affecting these markets since late 2005 were short-term:

- Hurricanes Katrina and Rita severely disrupted natural gas supplies in fall 2005, with resulting high prices.
- Generally mild weather – including the warmest U.S. January on record – resulted in a temporary glut of natural gas in the latter half of 2006, just one year after the hurricanes.
- Significant heat waves drove new peak electric loads in summer 2006, with brief increases in price.
- Two large hedge funds active in energy speculation failed as natural gas prices sagged from immediate post-hurricane levels.

The longer term trends over this period tended to elaborate on the trends identified previously by the Commission’s market oversight staff:¹

- Market responses to several incidents showed the continuing need for investment in domestic infrastructure in some regions.
- Electric generation increased its reliance on natural gas, with important implications for both industries.
- Supply and demand for liquefied natural gas (LNG) continued its global expansion, with important effects on U.S. energy markets.
- Futures and financial markets for energy commodities continued their rapid growth and integrated more tightly with cash physical markets, accompanied by increased concerns about possible effects of speculation.

Continued evolution of these energy markets in the face of short-term supply and demand disruptions provided challenges to market oversight efforts, and shows no prospect of slowing.

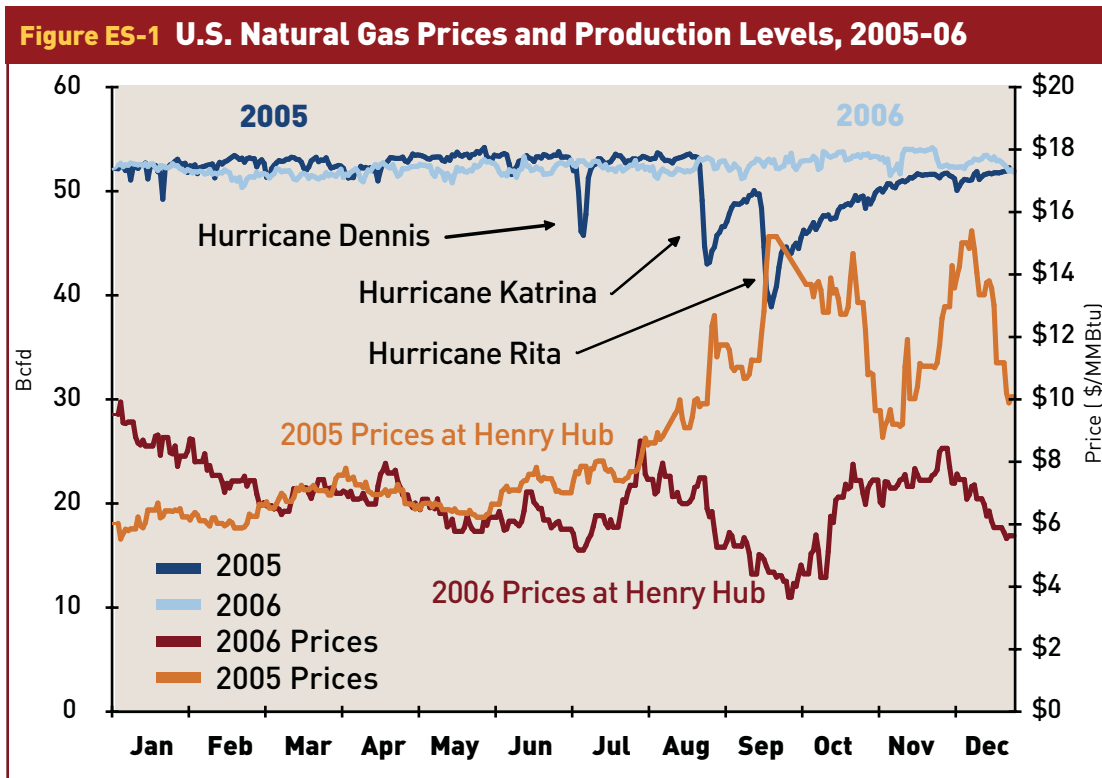
1. Comprehensive access to Commission staff work on market oversight is *available at*: www.ferc.gov/oversight.

SHORT-TERM ISSUES

Natural Gas: Extreme Weather Ends in Supply Abundance

Late in 2005, hurricanes Katrina and Rita inflicted unprecedented natural gas supply disruptions on the United States (see Figure ES-1). At the worst point, immediately after Hurricane Rita, domestic U.S. production dropped by more than 20 percent. At the time, however, U.S. natural gas storage was relatively full and injections continued in the face of disruptions to demand as well as supply.

The sharp price increases that resulted from the hurricanes were most severe in the eastern United States, which is more directly connected to the damaged Gulf Coast production facilities than other areas of the country. When the winter turned out to be unusually mild, the initially high storage inventories remained higher than historical averages into summer 2006, pushing prices down throughout the year. By fall 2006, storage had reached near-record levels, and LNG cargoes waited offshore in anticipation of higher winter prices, an unprecedented form of “offshore storage” that dissipated only in December.²



Derived from Platts and Bentek Energy Supply/Demand Balance data.

2. The U.S. Waterborne LNG Report, 2006 issues: Sept. 6; Oct. 5, 18, and 31; Nov. 10, 16, and 29; Dec. 7, 14, and 20.

Electric Power: Heat Waves, Record Loads, Significant Demand Response

The U.S. electric power industry faced a series of severe heat waves that affected almost every region during summer 2006. Most regions set peak load records, in some cases as much as 10% above previous records (see Table ES-1). The electric industry met these record loads with no major wholesale outages.

Table ES-1
New RTO Record Loads Set, 2006

Peak Loads				
RTO	Pre-06 (GW)	2006 (GW)	Increase %	2006 Peak Date
CAISO	45.4	50.3	10.7%	July 24
ERCOT	60.3	62.3	3.3%	August 17
SPP	40.5	42.2	4.2%	July 19
MISO	112.2	116.3	3.7%	July 31
PJM	133.8	144.6	8.1%	August 2
NYISO	32.1	33.9	5.6%	August 2
ISO-NE	26.9	28.1	4.5%	August 2

Derived from RTO data, using hourly integrated peak loads.

Reductions in demand for power from the grid by customers because of the stress of the heat waves seem to have proved important in preventing blackouts, particularly in areas that perennially face the threat of capacity shortages, including Connecticut and Long Island. These varied programs and efforts, known as demand response, tend to be poorly coordinated with short-term price signals from electricity markets but provided important relief to several electricity

systems during the stresses of the summer 2006 heat waves.

The larger weather pattern in 2006 was warmer than normal, and despite the new peaks, overall U.S. generation output fell a slight 0.1 percent in 2006.³

Financial Markets: Speculative Activity and Energy Markets

Continuing growth in financial trading of energy commodities in 2006 raised concerns about the possible effects of speculation on physical energy prices.

Speculation is the buying or selling of an interest in a commodity in the hope of profiting from future changes in the value of that commodity. Speculation is a necessary part of active markets, as is participation by buyers and sellers of the physical commodity. Robust markets rely on a variety of perspectives about current and future market conditions to reach workably competitive levels.

Several reports argued that speculators increased North American natural gas prices in 2006.⁴ In addition, the drop in natural gas prices in mid-2006 led to the collapse of two major speculators. The most notable of these was Amaranth Advisors LLC, which collapsed in September, apparently losing the most money ever by a hedge fund.⁵ A smaller fund, MotherRock L.P., failed at the end of July, wiping itself out as well as losing an additional \$60-\$100 million for its broker.⁶

3. Derived from Edison Electric Institute (EEI), Weekly Electric Output data.

4. Mark N. Cooper, for the Midwest Attorneys General Natural Gas Working Group (Illinois, Iowa, Missouri, Wisconsin), *The Role of Supply, Demand, and Financial Commodity Markets in the Natural Gas Price Spiral*, March 2006; U.S. Senate Permanent Subcommittee on Investigations, Committee on Homeland Security and Governmental Affairs, *The Role of Market Speculation in Rising Oil and Gas Prices: A Need to Put the Cop Back on the Beat*, (Washington, D.C., June 27, 2006); Robert J. Shapiro and Nam D. Pham, *An Analysis of Spot and Futures Prices for Natural Gas: The Roles of Economic Fundamentals, Market Structure, Speculation, and Manipulation*, August 2006. Work conducted by Sonecon LLC and supported by a grant from the National Legal and Policy Center.

5. "A Hedge Fund's Loss Rattles Nerves," Sept. 19, 2006, "Hedge Fund Shifts To Salvage Mode; Amaranth Trying to Shed Gas Portfolio," Sept. 20, 2006, by Gretchen Morgenson and Jenny Anderson, *The New York Times*; "Blue Flameout: How Giant Bets on Natural Gas Sank Brash Hedge-Fund Trader," Ann Davis, Sept. 19, 2006, *The Wall Street Journal*; "Amaranth - How to Lose \$5.0 Billion without Even Trying," By Cal Payne, Sept. 25, 2006, *IssueAlert@UtiliPoint.com*.

6. "MotherRock Cries Uncle," *thetstreet.com*, Aug. 3, 2006; "Energy Hedge Fund Closes Shop," *CNNMoney.com*, Aug. 4, 2006.

LONG-TERM ISSUES

Infrastructure: a Continuing Need for Investment

Natural gas and electric power markets signal infrastructure needs by raising prices where the balance of supply and demand is tight. The difference in prices between these locations and others is known as *congestion*. Examples of how transportation infrastructure can affect congestion include:

- **Coal.** Two train derailments in southern Wyoming reduced shipments of Powder River Basin coal in May 2005, drove down electric generator stockpiles, and changed the generation supply mix in some places.
- **Natural Gas and Hurricane Damage.** When hurricanes Katrina and Rita damaged gas production and transportation in the Gulf of Mexico, gas prices increased in the East, which attracted more gas from Texas, filled pipelines heading east, and led to persistently large East/West price differences.
- **Access to Gas Supplies in the Rocky Mountains.** As a result of tight pipeline capacity to export natural gas from western Wyoming, five times in the fall of 2006 relatively minor changes in pipeline infrastructure led to significant price changes.
- **Electric Prices in New York City and on Long Island.** Several new power plants in New York City reduced traditional transmission constraints into the city, dropping prices relative to still-constrained Long Island.

Natural gas and electric power markets remain

sensitive to infrastructure shortages, underscoring the importance of investment in transportation and transmission infrastructure before serious problems can arise.

Growing Reliance on Natural Gas for Electric Generation

Though U.S. electric power generation dropped slightly in 2006, power generators used 19.2 Bcf of natural gas per day through November 2006, up 6.2 percent from 2005.⁷ Gas use on the peak day in 2006 was estimated to be 31 percent greater than on the peak day in 2005, peaking at roughly 42 Bcf on August 2 (see Figure ES-2).⁸

Natural gas use in electric generation increased for several reasons. Much more natural gas generating capacity was added over the past few years, even as plants using other fuels retired. In addition, natural gas traded at prices lower than competing fuel oil products in some markets, resulting in a shift in fuel use to natural gas.

Electric power prices are increasingly influenced by natural gas prices. Though natural gas accounts for only about 20 percent of the power generated in the country,⁹ it is often the fuel used by the plants that are the first to be turned off or on and consequently the ones that set the price for power in a region.

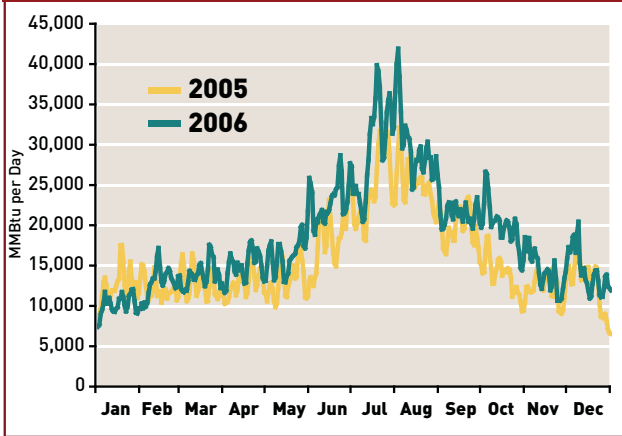
For natural gas, electric generation load has largely substituted for traditional industrial load that was lost as natural gas prices rose at the beginning of the decade. Generation load tends to be inflexible, resulting in additional volatility in natural gas prices.

7. EIA, *Monthly Flash Estimates of Electric Power Data*, "Table 5.1 Trends in Fossil Fuel Consumption For Electric Generation, Total (All Sectors)," Jan. 19, 2007.

8. According to Bentek Energy LLC's *U.S. Power – Gas Burn Report*. The peak day in 2005 was Aug. 3.

9. EIA, *Electric Power Annual 2005* and *Electric Power Monthly*, January 2007.

Figure ES-2 Estimated Natural Gas Delivered to U.S. Power Plants, 2005-06



Derived from Platts and Bentek Energy Supply/Demand Balance data.

Evolving Global LNG Market

Because of short-term market drivers, LNG imports into the United States actually declined in both 2005 and 2006.¹⁰ Over the long term, however, imports are expected to grow as natural gas production in North America becomes increasingly difficult and

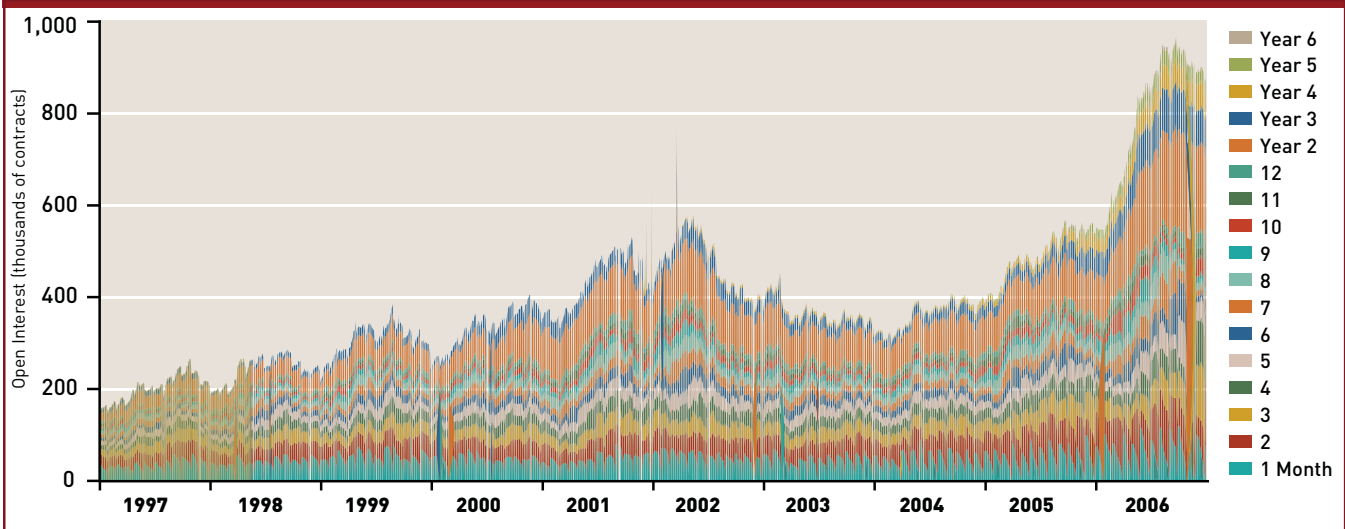
expensive. LNG import projects continue to move forward in the Gulf of Mexico as well as on the East and West coasts and in Mexico and Canada.

In prior years, we observed a growing North Atlantic spot market for LNG that could flow either to North America or to Europe. In 2006, the LNG market in the Atlantic and Mediterranean basins expanded to send tankers as far away as Asia.

Futures and Financial Markets Continue to Grow in Size and Influence

Futures and financial trading in energy commodities including natural gas and electricity continued to increase in 2005 and 2006.¹¹ Indicators from transparent parts of these energy markets show that participants developed new products to trade, traded greater volumes, and showed a greater willingness to hold on to sales or purchase commitments (measured as *open interest*, see Figure ES-3). Futures and financial trading was particularly apparent in natural gas, but trading in electricity increased as well.

Figure ES-3 Natural Gas Open Interest Growth, 1997-2006



Derived from Nymex data.

10. EIA, *U.S. Natural Gas Imports by Country*, and *The U.S. Waterborne LNG Report*.

11. Nymex futures is a physical market in that the commitments traded provide for physical delivery and are occasionally used for that purpose. More generally, however, traders sell (or buy) their futures commitments before settlement, allowing for participants without physical interests to participate. Consequently, we will treat futures and financial markets together because of their interactions with cash physical markets, notwithstanding the very real differences between futures and financial trading.

Futures and financially traded natural gas markets interact with other commodity trading. For example, some interest in trading natural gas comes from speculators, and some from those, like pension funds, that have little interest in energy in its own right but want changing value for natural gas (and other basic commodities) as part of a balanced portfolio that includes many other investments.

Futures and financial trading also interacts with various physical natural gas markets. Observers tend to think of futures and financial energy commodity trading as *derivative* of an underlying physical market, with futures and financial trading reflecting both speculation and short-term physical supply and demand conditions.

Over time, some successful futures markets have become robust and transparent enough that their prices are used directly to set cash physical prices. For example, monthly indices used in much of the eastern half of the United States have become directly dependent on the final monthly settlement price of futures contracts traded on the New York Mercantile Exchange (Nymex) to set their prices. Publishers of these indices use *physical basis* transactions to calculate some or all of their price indices. In effect, the flow of information regarding these physical prices now comes directly from futures trading.

HOW TO USE THIS REPORT

In the past, Commission staff produced three comprehensive *State of the Markets Reports* in document form, usually significantly after the period in question. With this report, we are changing the form of the *State of the Markets Report* to take advantage of the speed and flexibility of the Commission's new Market Oversight pages on its Web site.

These pages are available at www.ferc.gov/oversight.

Instead of providing significant amounts of regional data within the report itself, the annual *State of the Markets Report* will now consist of a summary of significant national electric and natural gas market developments over the previous year. Regional detail will be provided, and updated more regularly, within the Web pages themselves.

We hope that the Market Oversight section of the Commission Web site will engage stakeholders in a meaningful review of energy market activity by sharing much of the information we use to assess that activity. Over the course of the year, with the addition of information as it becomes available, we expect that the site will become increasingly comprehensive and useful.



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Section 1 **INTRODUCTION**

Natural gas and electric power markets in the United States responded effectively to major supply and demand difficulties in 2005 and 2006. Still, both markets face a challenging future in responding to increasingly integrated global energy markets.

RESPONDING TO CHALLENGES

In 2005, United States natural gas supplies faced unprecedented disruption from hurricanes Katrina and Rita. These severe supply disruptions led to sharp price increases that were most severe in the eastern United States. Nonetheless, the natural gas industry entered the winter of 2005-06 with strong storage inventories. When the winter turned out unusually mild, natural gas inventories remained high into 2006. High inventories through the year kept downward pressure on gas prices. Section 2, *Natural Gas Markets 2005-06*, describes key developments in natural gas markets during the year.

During summer 2006, the U.S. electric power industry faced a series of short, severe heat waves that affected almost every region. Most regions set peak load records, some as much as 10% above previous record loads. Nonetheless, the bulk power system overall suffered no major reliability problems, though some local distribution systems saw severe problems (especially in New York City as well as in and around St. Louis). Regional transmission organizations (RTOs)¹ continue to be the most important market institutions in the regions where they operate. Section 3, *Electric Markets 2005-06*, describes key developments in electric markets during 2005 and 2006.

MARKET INTEGRATION

In 2005 and 2006, U.S. physical energy markets became more integrated, both among themselves and with global energy markets. Although we often consider energy markets as distinct (e.g., electricity and natural gas), they increasingly influence one another. Greater integration among physical energy markets offers significant benefits to market participants and policy makers alike, but also presents a challenge. Key areas of integration in 2006 included the following:

Transportation Infrastructure and Commodity Markets

Even relatively small, isolated transportation network outages will have effects on local commodity pricing. In fact, one of the important characteristics of markets for natural gas and electric power is that they inherently signal tight infrastructure conditions with large price movements because of the short-term price inelasticity of demand for these products. This signaling of local market stress provides the logic behind locational pricing in RTOs. Section 4, *Infrastructure Outages and Their Effects on Energy Markets*, describes several examples of the effects of transportation infrastructure outages in 2005 and 2006:

- **Coal.** Two train derailments in southern Wyoming reduced shipments of Powder River Basin coal, starting in May 2005. Over time, the resulting limitations reduced coal stockpiles for many generators, changed the generation mix used in some parts of the country and spurred changes in business strategy for some generators.
- **Post-Hurricane Natural Gas Flows.** Hurricanes Katrina and Rita severely damaged the most important natural gas supply basin to the eastern United States, centered in the Gulf of Mexico. As a result, rising gas prices in the East attracted more gas from Texas, loading pipelines heading east from Texas and leading to persistent large price differences between trading points in the eastern and western parts of the United States.
- **Western Wyoming Natural Gas.** Western Wyoming produces much more natural gas than it consumes, and pipeline capacity to export supplies is tight. Five times in fall 2006, relatively minor changes in infrastructure availability led to significant price changes.
- **Changing Electric Price Patterns Between New York City and Long Island.** With the addition of several new power plants in New York City, traditional transmission constraints into the city diminished somewhat and the constraints into Long Island became comparatively more important. Regional real-time prices in the New York Independent System Operator (NYISO) area reflected these changes.

1. For simplicity, this paper will refer to existing centrally managed real-time, day-ahead, and ancillary electricity markets as "RTOs" – short for "Regional Transmission Organizations." In fact, we will include under that designation similar markets run by "Independent System Operators" as well.

Interdependence Among Energy Markets

Section 5, *Increasing Interdependence Among Energy Markets*, shows that the interaction of markets for various fuels and other energy inputs created unexpected results in 2005 and 2006:

- **Integration of Natural Gas and Electric Markets.** Some natural gas and electric markets operate over short time frames (often within the day) and with tight engineering tolerances. Natural gas is frequently the marginal (or, last unit chosen) fuel for power, especially when markets are under stress. A series of incidents show that the two markets must complement each other closely to maintain efficient market operations and reliability.
- **Natural Gas and Oil.** World oil prices continue to provide a floor for U.S. natural gas prices. Even so, gas prices fell during 2006 below competing residual fuel oil prices in key downstream markets for most of the year. As a result, electric generators and large industrial customers with fuel-switching capability, primarily located in Florida, New York, and New England, switched to natural gas.
- **LNG.** The global liquefied natural gas (LNG) market continued to mature in 2005 and 2006. Over the long term, the United States will rely more heavily on LNG imports. Investment in new capacity continues, reflecting the belief of most market participants that imports will increase in the future. Over the short term, competition for LNG supplies increased not only with Europe but also with Asia. Imports declined slightly for the past two years because of hurricane-related infrastructure outages in 2005 and relatively low U.S. prices in 2006.

Demand Response

Demand response helped the electric industry respond to the heat waves of 2006 even though most demand-response programs had little or no connection to the mechanics of electricity markets. These programs lowered peak loads, especially in constrained regions like Long Island and southwest Connecticut. Section 6, *Demand Response in Summer 2006*, reports on the experience with these programs in different regions.

Physical and Financial Markets

Financial market activity increased, especially for natural gas. Both electric and natural gas financial products saw increases in trading. Open interest (how many futures contracts remain unsettled each day) for the natural gas futures contract traded on the New York Mercantile Exchange (Nymex) increased sharply in 2006. This increase appears to have resulted from a continuing influx of both passive (e.g., pension funds) and active financial investment (e.g., hedge funds). Both types of market speculation appear to have influenced prices through 2005 and 2006.

In certain cases, prices from financial markets directly set important physical prices. For example, monthly physical basis deals directly link some indexed physical natural gas prices to the closing price for futures trading (especially in the Northeast). In those cases, financial prices no longer appear to be *derivative* of the physical prices, but actually help to set them. Section 7, *Growing Influence of Financial Energy Markets*, describes the interaction between physical and financial markets in 2005 and 2006.



Section 2

NATURAL GAS MARKETS: 2005-06

The most important factor in natural gas markets during 2005 and 2006 was the destruction wrought by hurricanes Katrina and Rita. Immediately after the storms, U.S. domestic production fell dramatically and prices rose as a result. Through 2006, however, supplies have been relatively abundant and prices lower.

What happened? The unusually mild winter of 2005-06 led to high gas storage inventories in early 2006. Storage levels remained high throughout the year, despite lower imports and higher natural gas use in electric generation during the summer.

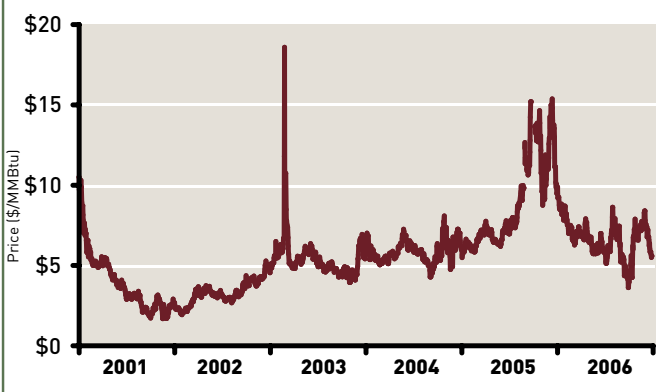
NATURAL GAS IN 2005

Prices

Natural gas prices were rising during summer 2005, even before hurricanes Katrina and Rita, continuing a trend that began in late 2001 (see Figure 1)². The increased prices were a response to many forces, including increasing crude oil prices (driven by world economic growth), a general decline in North American natural gas production since the early 1990s, and rising demand for gas-fired power generation.

Fig 1

Henry Hub Natural Gas Daily Spot Prices, 2001-06



Derived from Platts data.

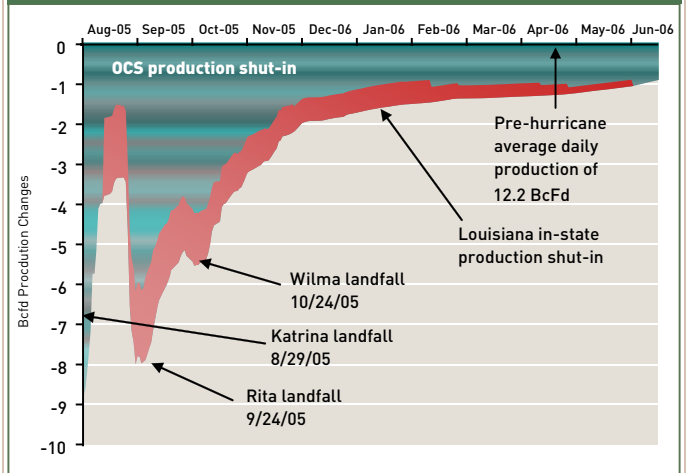
Hurricanes

The hurricanes damaged or destroyed significant natural gas supply infrastructure in the Gulf of Mexico in August and September 2005, including onshore processing plants and other facilities, as well as offshore platforms and pipelines. The resulting production drop, 85 percent of Gulf of Mexico production, was historically remarkable – almost 14 times as much lost production from hurricane-related damage as the average of the 10 years before 2005 (see Figure 2). Significant amounts of production remained offline well into 2006; at least 750 MMcf³ of offshore Gulf production may never

return. Total deliveries from interstate natural gas pipelines in Louisiana dropped by almost half for October 2005, and significant volumes remained offline through the winter.

Fig 2

Natural Gas Production Lost due to Hurricane Infrastructure Damage, 2005



Derived from MMS, Hurricane Katrina/Hurricane Rita Evaluation and Production Shut-In Statistics Report.

Prices rose significantly in all regions after the hurricanes, but especially in areas east of the Texas-Louisiana border, including the entire East Coast (see Figure 3). Prices showed hurricane-related effects throughout the rest of 2005.

In addition, the hurricanes disrupted natural gas markets in several ways, especially in Louisiana. From September 27 through October 7, 2005, the IntercontinentalExchange (ICE) reported no next-day Henry Hub prices because flooding halted physical deliveries there. To manage requirements in the face of the facilities outage at Henry Hub, several market participants changed commercial arrangements, using more costly routing of gas to secure supplies from alternate receipt points. Lack of real-time information about supply chain availability made decision-making uncertain and may have increased risk premiums.

2. Unless otherwise noted, all price data are in nominal U.S. dollars.

3. Staff phone call with Robert W. Esser, Cambridge Energy Research Associates (CERA), Jan. 3, 2007.

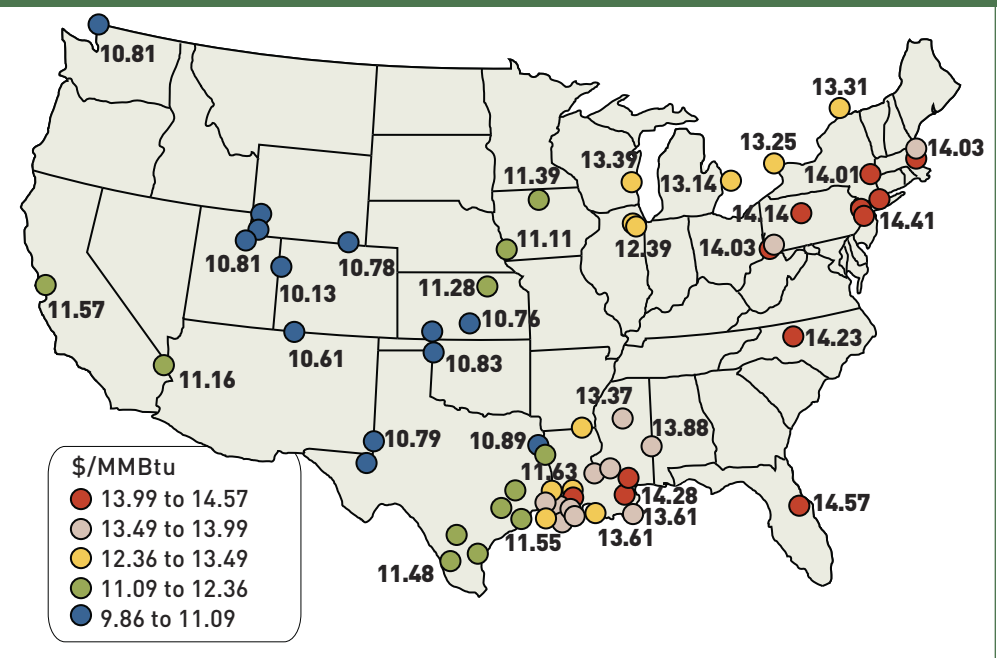
NATURAL GAS IN 2006

The natural gas market recovered rapidly from the hurricanes, largely because the winter of 2005-06 was the fifth warmest U.S. winter on record and included the warmest January.⁴ Prices fell through much of 2006, rising some during the heat of the summer and again in the early winter. As has been typical for several years, prices were higher in the East than the West, though the East-West price difference was much smaller than immediately after the hurricanes (see Figure 4).

Overall, natural gas prices remained higher in 2006 than in any year except 2005, primarily because world oil prices (which were high in 2006) appear to have prevented natural gas prices from falling further (see Section 5, *Increasing Interdependence of Energy Markets*). This pattern of prices across energy markets produced unusual supply and demand conditions during the year: high storage and a near glut of gas in fall 2006 along with high levels of drilling in the United States, increased electric generation load, and lower imports.

Fig 3

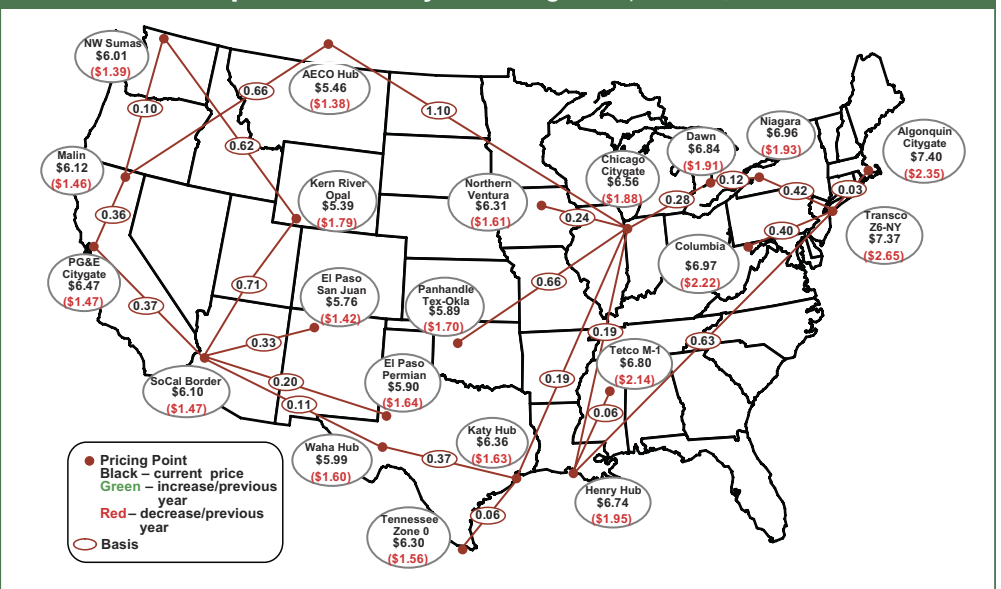
Average Post-Hurricane Natural Gas Prices, October 8-14, 2005



Source: Derived from Platts data, using Platts PowerMap.

Fig 4

U.S. Natural Gas Spot Prices at Major Trading Hubs, 2006 (\$/MMBtu)



Source: Derived from Platts data.

4. National Oceanic & Atmospheric Administration (NOAA), *U.S. National Overview: January [2007] and Winter 2006*, available at: <http://www.ncdc.noaa.gov/oa/climate/research/2006/feb/national.html>.

High Storage

Faced with relatively low demand throughout the winter of 2005-06, natural gas market participants drew down storage inventories far less than has been typical over the last decade. As a result, at the beginning of the 2006 injection season (April 1), storage inventories were 38 percent above the previous five-year average (see Figure 5). Storage levels remained high throughout the summer and by October 31, the end of the traditional injection season, gas storage stood at 3,452 Bcf, only 20 Bcf short of the record high of 3,472 Bcf set at the end of November 1990.

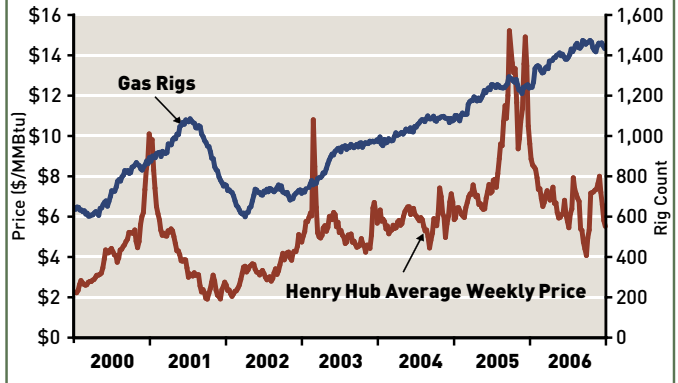
Drilling and Production

In response to rising prices before the hurricanes, drilling for new supplies of natural gas increased (see Figure 6). Drilling activity remained high throughout 2006 in the United States, even as prices receded. Though 2006 saw more Canadian drilling than 2005, and both had more drilling than previous years, Canadian gas drilling has begun to decline in recent months (see Figure 7).

Production in the United States for the first six months of 2006 fell 1.3% from the first half of 2005 because of lingering

Fig 6

Increased U.S. Drilling Due to Historically High Natural Gas Prices

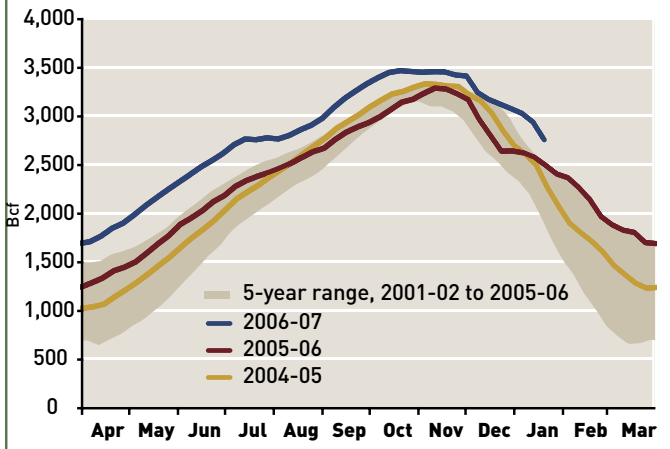


Source: Derived from Platts data and Baker Hughes North American Rotary Rig Count data.

outages from the hurricanes. Nonetheless, increased drilling in the United States over the past few years appeared to affect markets (see Figure 8) as increased production made up more than half of the continuing hurricane-related outages. That is, even with the effect of the hurricanes, new production more than offset the effects of normal depletion, reversing a long-term trend, at least temporarily. Energy Information Administration (EIA) data for the first 11 months of 2006 show a 1.9% increase in gas production over the comparable 2005 period.⁵

Fig 5

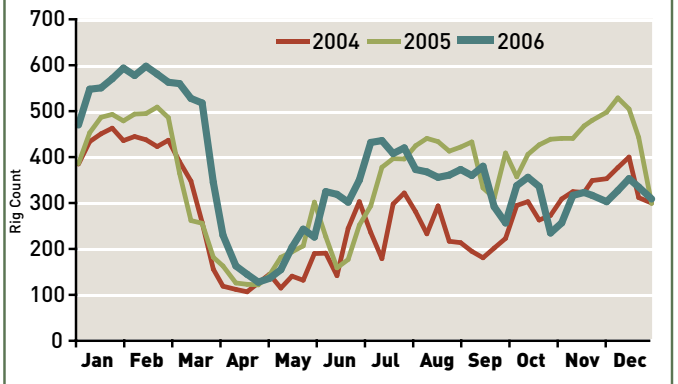
U.S. Natural Gas Storage Inventories



Source: Derived from EIA Weekly Natural Gas Storage Report data.

Fig 7

Recent Decline in Canadian Drilling

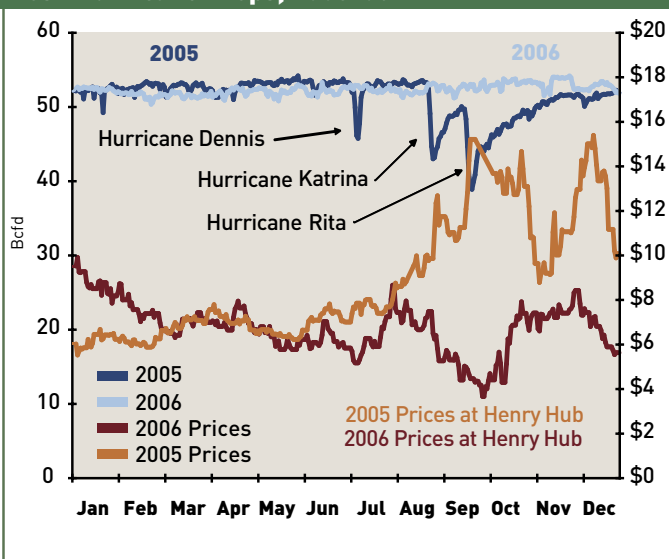


Source: Derived from Baker Hughes North American Rotary Rig Count data.

5. EIA, "Table 2. Supply and Disposition of Dry Natural Gas in the United States, 2001-2006," *Natural Gas Monthly*, Jan. 30, 2007, available at: http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_monthly/ngm.html.

Fig 8

U.S. Natural Gas Production Recovers After Post-Hurricane Drops, 2005-06



Source: Derived from Platts and Bentek Energy Supply/Demand Balance data.

Increased Electric Generation Load

Global oil prices remained at historically high levels through 2006. Natural gas prices generally stayed above historical levels as well, but they fell below prices for residual fuel oil – also used to fuel power generation – for most of the year in key markets. As a direct result, switching to natural gas use from oil for electric generation increased regionally, especially in New York, New England, and Florida. Section 5, *Increasing Interdependence of Energy Markets*, discusses this trend in more detail. EIA reported that generators used 857 Bcf of natural gas in the United States in July 2006, the highest monthly volume for the past five years.⁶

Lower Imports

Despite the increased use of natural gas for electric generation, the United States imported less natural gas both from Canada and from overseas as LNG (see Table 1).⁷ Reductions in imports from Canada may be related to dropping prices and alternative uses for the gas in Canada, including development of nonconventional oil resources. LNG trends reflect relative international prices, as discussed in Section 6 as well.

Table 1: Trends in U.S. Imports of Natural Gas 2004-06

	Net Imports in MMcf			% Change in Net U.S. Imports	
	2004	2005	2006	2004-05	2005-06
Net Canadian Imports	3,211,958	3,351,493	3,232,270	4.3%	-3.6%
Net Mexican Imports	(397,086)	(295,634)	(281,378)	25.5%	4.8%
Net LNG Imports	589,916	566,136	523,505	-4.0%	-7.5%
Total Net Imports	3,404,788	3,621,996	3,474,397	6.4%	-4.1%

Source: Staff analysis of EIA U.S. Natural Gas Imports by Country, Bentek Energy Import/Exports and LNG, and The U.S. Waterborne LNG Report data.

6. EIA, "Table 2.4.A. Natural Gas: Consumption for Electricity Generation by Sector," *Electric Power Monthly*, Jan. 12, 2007, available at: http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html.

7. Staff derived data from several sources. 2004 and 2005 imports are based on EIA data. *The U.S. Waterborne LNG Report* supplied data for 2006 LNG imports. Staff estimated U.S. LNG gas exports from Alaska to Japan as equal to the average of first 9 months of 2006 times 12 months. Net Canadian and Mexican gas imports were derived from Bentek Energy information and converted into MMcf.

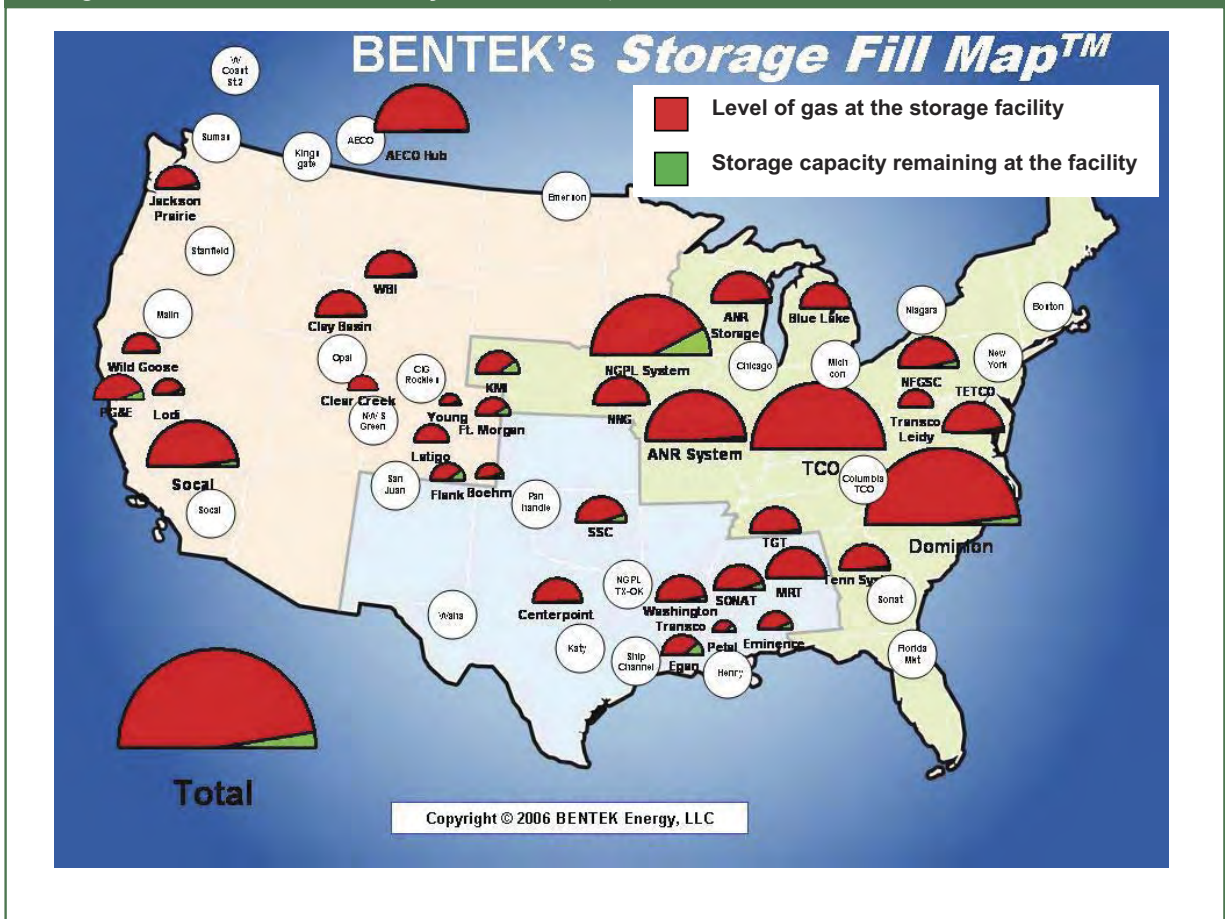
Fall 2006: Gas Glut?

By September and October of 2006, natural gas markets showed signs of glut. Virtually all storage fields in the United States were full by October 26, near the end of the traditional injection season (see Figure 9). Prices fell as low as \$3.66/MMBtu at Henry Hub in early October – the lowest level in four years.

Through late 2006, deliveries of LNG cargoes to U.S. terminals dropped to low levels, though storage at LNG terminals

remained unusually high. Some full LNG tankers even stayed offshore, waiting for higher U.S. prices.⁸ Holding full LNG tankers offshore is costly, both because of the carrying costs of the investment in the natural gas and because some of the LNG evaporates while at sea. Nevertheless, the practice made economic sense because anticipated – and “hedgeable” – prices going into the winter were far higher than fall prices. As a result, the tankers became a form of offshore storage for the North American market.

Fig 9
Storage Levels at the End of the Injection Season, 2006



Source: Bentek Energy Weekly Storage Report.

8. *The U.S. Waterborne LNG Report*, 2006 issues: Sept. 6; Oct. 5, 18, and 31; Nov. 10, 16, and 29; Dec. 7, 14, and 20.

Summer and Winter Price Differentials

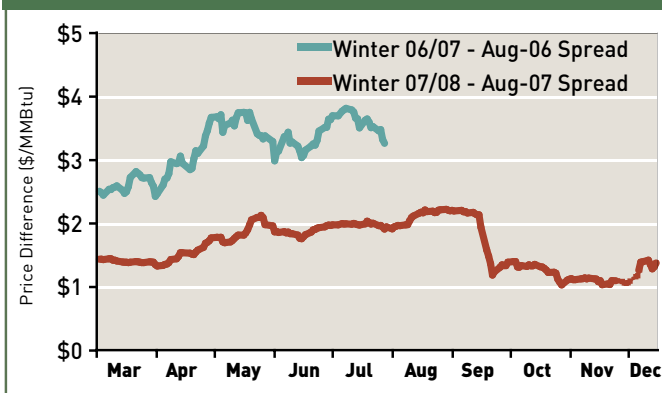
Price differences between summer and winter (as reflected in Nymex futures prices) were higher than historical norms in 2006. Figure 10 shows price differentials between August (a representative summer month) and winter for natural gas going into the winters of 2006-07 and 2007-08. The difference between August and winter prices is (among other things) the valuation the market places on natural gas storage for the year.

Futures prices into the future (known as the forward price curve through 2006) showed a premium of more than \$3.00/MMBtu in forward prices for winter 2006-07 (until the August contract expired at the end of July 2006 – blue line on the graph). Such a difference was a much higher premium than in the past, when premiums tended to be around \$0.70 per MMBtu. Some of the unusually high premium probably reflected the overhang of gas supply in summer 2006; during the same months, market participants placed about a \$2.00/MMBtu premium on winter supplies for 2007-08 (compared to summer 2007), indicating that they expected the differential to fall in the following year.

Part of the \$2.00 differential for future years may also have been caused by transient factors, since the premium for 2007-

Fig 10

Difference between August and Winter Natural Gas Futures in 2006



Note: Winter is defined as November – March
Source: Derived from Nymex data.

08 fell to about \$1.00 per MMBtu in October 2006. But even the remaining \$1.00 differential is about \$0.30 higher than the historical average of the years just before hurricanes Katrina and Rita.⁹ It indicates the high value that market participants place on natural gas storage in future years. In response to the need for more storage, the Commission undertook an initiative to encourage the development of more natural gas storage in coming years.¹⁰

9. This may reflect a real change in fundamentals, as the North Atlantic LNG market tends to deliver more to North America in summer and less in winter because storage is more abundant in North America than in Europe.

10. *Rate Regulation of Certain Natural Gas Storage Facilities*, Order No. 678, 115 FERC ¶ 61,343 (2006), and *order on clarification and reh'g*, Order No. 678-A, 117 FERC ¶ 61,190 (2006).



Section 3

ELECTRIC MARKETS: 2005-06

Electric power markets responded to several important events during 2005 and 2006. The most significant involved responding to changing conditions in underlying fuel markets, especially for natural gas and coal. In addition, the electric industry performed reliably in the face of several periods of record power generation requirements caused by intense heat during the summer of 2006. This section will review those issues and discuss developments in electric market institutions, both generally and within RTO markets.

ELECTRIC MARKET RESPONSES TO FUELS MARKETS

In 2005, wholesale, next-day, on-peak power prices ranged from \$61.76/MWh to \$110.03/MWh, up from a range of \$42.03-\$76.63 in 2004, as the prices of oil, natural gas, coal, and emissions allowances all increased rapidly. In

Table 2: Electricity Prices and Input Prices, 2004-06

	2004	2005	2006
Electric Prices (\$ per MWh)			
Mass Hub	\$61.53	\$89.94	\$69.85
Cinergy	\$43.33	\$63.76	\$51.80
SP-15	\$55.19	\$73.14	\$61.94
Inputs			
Natural Gas (\$ per MMBtu)			
Henry Hub	\$5.85	\$8.69	\$6.74
New York	\$6.73	\$10.16	\$7.36
Southern California	\$5.50	\$7.64	\$6.08
Coal (\$ per ton)			
Central Appalachian (Eastern)	\$54.39	\$59.99	\$51.64
Powder River Basin (Western)	\$6.56	\$9.85	\$13.21
Emissions (\$ per ton)			
SO ₂ Allowances	\$442.95	\$901.21	\$738.12
NO _x allowances	\$2,273.77	\$2,770.87	\$1,862.03
Oil			
WTI (Crude - \$ per barrel)	\$41.44	\$56.48	\$66.11
Residual Fuel, NY (\$/barrel)	\$35.13	\$50.43	\$55.07
Distillate Fuel, NY (\$/gallon)	\$1.28	\$1.86	\$2.04

Source: Derived from Platts, Bloomberg and Cantor Fitzgerald data. SO₂ prices are based on monthly averages.

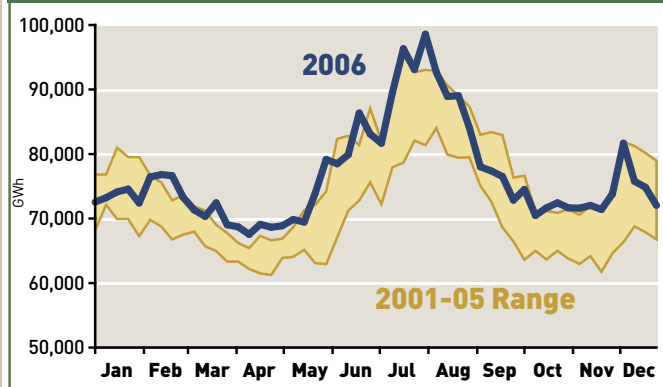
2006, power prices fell, though not to 2004 levels, to a range of \$50.12-\$86.01. This decrease in power prices reflected declining input prices, especially for natural gas, coal, and emissions allowances (see Table 2).

Generation

U.S. generation decreased by 0.1 percent in 2006 compared to 2005.¹¹ Total generation was still at or near the top of the five-year range for most of the year, except during winter periods when the weather was unusually warm (see Figure 11).

Fig 11

U.S. Electricity Output, 2001-06



Source: Derived from EEI Weekly Electric Output data.

The mix of generation did change somewhat. According to data from EIA, overall generation in 2006 through October increased 0.2 percent, while gas-fired generation increased 6.8 percent.¹² There were slight increases in nuclear and hydroelectric generation as well, but renewables jumped almost 11 percent, largely on a 47.4 percent increase in wind generation.¹³ Wind generation capacity grew by 27 percent in 2006 to 11,603 MW,¹⁴ representing approximately \$4 billion in additional investment.

11. Edison Electric Institute's (EEI) *Weekly Electric Output* covers the Lower 48 states only.

12. EIA, *Electric Power Monthly*, "Table 1.1. Net Generation by Energy Source: Total (All Sectors)," released Jan. 12, 2007, available at: www.eia.gov/cneaf/electricity/epm/table1_1.html.

13. EIA, *Electric Power Monthly*, "Table 1.1.A. Net Generation by Other Renewables: Total (All Sectors)," released Jan. 12, 2007, available at: www.eia.gov/cneaf/electricity/epm/table1_1_a.html.

14. DOE, EERE, Wind and Hydropower Technologies Program, available at <http://www1.eere.energy.gov/windandhydro/index.html>, and American Wind Energy Association (AWEA), "Wind Energy Project Database," as noted in press release, Jan. 23, 2007. Due to project decommissioning and repowering, the end-of-year cumulative capacity total does not always match the previous year's year-end total plus additions.

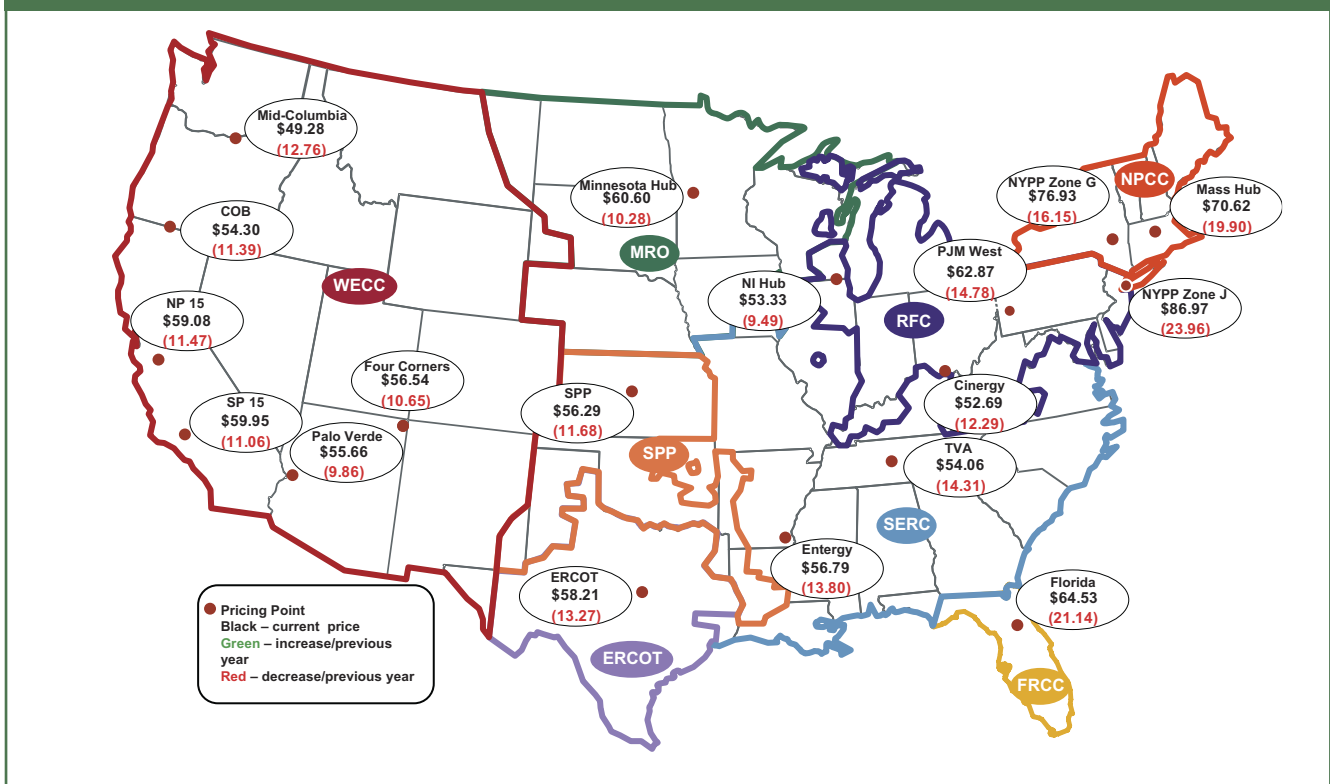
During the spring and fall of 2006, when loads are typically at their lowest seasonal levels, total U.S. generation was consistently above the five-year average. Because these periods have less heating and cooling load, the higher generation levels during these periods may indicate increased demand due to underlying economic growth or proliferation of new electricity-based technologies.

Prices

Price patterns were fairly similar across the United States, rising in 2005 and falling in 2006 in almost all regions (see Figure 12), for both on-peak and off-peak deliveries (see Table 3 for detailed price patterns by region). Regional 2006 declines in on-peak power prices consistently ranged between a quarter and a third of 2005 prices, except in Minnesota where the 2006 decrease ranged from roughly 15 percent to 30 percent.¹⁵

Fig 12

Average On-Peak Spot Electric Prices, 2006 (\$/MWh)



Source: Derived from Platts data.

15. Market pricing points include transactions for delivery at one or more physical locations. The map simplifies geography by plotting a representative single location for each pricing point. Staff averaged prices over the 16-hour peak period.

In general, on-peak price reductions in 2006 primarily reflected trends in natural gas prices. Natural gas tends to be on the margin for on-peak periods in most of the United

States most of the time. Off-peak price changes in 2006 showed more variability, falling only slightly or even rising in regions that depend heavily on coal.

Table 3: On-Peak and Off-Peak Electric Prices, 2004-06

	On-Peak Spot Prices					Off-Peak Spot Prices				
	2004 \$	2005* \$	2006 \$	% Change 04-05	% Change 05-06	2004 \$	2005* \$	2006 \$	% Change 04-05	% Change 05-06
Northeast										
Mass Hub	61.47	89.87	70.33	46.2%	-21.7%	42.94	61.79	47.45	43.9%	-23.2%
Ny Zone G	61.74	92.46	76.53	49.8%	-17.2%	42.86	63.70	50.54	48.6%	-20.7%
NY Zone J	76.63	110.03	86.47	43.6%	-21.4%	48.28	72.61	55.05	50.4%	-24.2%
NY Zone A	52.49	76.04	59.34	44.9%	-22.0%	36.82	53.26	42.20	44.6%	-20.8%
PJM West	51.10	76.64	62.92	50.0%	-17.9%	30.15	40.72	36.36	35.1%	-10.7%
Southeast										
VACAR	48.27	71.88	57.20	48.9%	-20.4%	25.23	38.13	34.96	51.1%	-8.3%
Southern	48.67	70.88	56.15	45.6%	-20.8%	26.01	37.54	33.86	44.3%	-9.8%
TVA	44.23	67.39	53.91	52.4%	-20.0%	22.14	34.24	32.76	54.7%	-4.3%
Florida	58.31	84.95	65.06	45.7%	-23.4%	29.02	42.88	39.78	47.8%	-7.2%
Entergy	45.76	69.95	56.65	52.9%	-19.0%	23.04	38.02	34.06	65.0%	-10.4%
Midwest										
Cinergy	43.31	63.76	52.39	47.2%	-17.8%	19.88	29.12	29.93	46.5%	2.8%
ECAR North/Michigan Hub*	45.58	67.13	55.94	47.3%	-16.7%	21.00	30.84	29.30	46.9%	-5.0%
MAIN North/Minnesota Hub*	47.94	64.70	58.67	35.0%	-9.3%	20.28	28.78	25.73	41.9%	-10.6%
NI Hub	42.03	61.76	53.15	46.9%	-13.9%	17.57	28.71	28.35	63.4%	-1.3%
MAIN South/Illinois Hub*	42.85	63.38	51.73	47.9%	-18.4%	18.41	28.70	25.54	55.9%	-11.0%
MAPP North/Minnesota Hub*	47.06	65.06	58.67	38.2%	-9.8%	19.12	28.57	25.73	49.4%	-9.9%
MAPP South	45.90	65.48	55.56	42.7%	-15.1%	19.00	28.01	32.61	47.4%	16.4%
South Central										
SPP North	45.19	67.44	56.23	49.2%	-16.6%	20.55	34.82	33.91	69.4%	-2.6%
ERCOT	47.32	70.95	58.74	49.9%	-17.2%	31.45	47.95	39.09	52.5%	-18.5%
Southwest										
Four Corners	50.51	69.39	58.79	37.4%	-15.3%	35.45	46.74	36.45	31.8%	-22.0%
Palo Verde	50.09	67.39	57.85	34.5%	-14.2%	35.44	47.10	36.91	32.9%	-21.6%
Mead	51.91	70.18	59.79	35.2%	-14.8%	37.47	49.02	38.44	30.8%	-21.6%
Northwest										
Mid-C	44.54	62.95	49.52	41.3%	-21.3%	39.27	50.21	37.23	27.9%	-25.9%
COB	49.09	66.95	55.08	36.4%	-17.7%	40.58	51.71	39.14	27.4%	-24.3%
California										
NP15	54.46	72.49	60.81	33.1%	-16.1%	41.35	51.35	39.17	24.2%	-23.7%
SP15	55.20	73.03	61.77	32.3%	-15.4%	39.26	51.22	40.07	30.5%	-21.8%

* As of April 1, 2005, ECAR North became Michigan Hub, MAIN North became Minnesota Hub, MAIN South became Illinois Hub and MAPP North became Minnesota Hub. Note: Table was revised March 1, 2007.

Source: Derived from Platts day-ahead peak indices and ISO average day-ahead prices.

SUMMER HEAT WAVES

Summer 2006 was notable for a few episodes of very hot weather, some virtually simultaneous across the United States, that led to short-term price increases. In the West, the hottest weather occurred during a single 11-day hot spell from July 17 to July 27. The Midwest and East saw three shorter periods of intense heat during June, July, and especially the beginning of August.

Demand

Almost every region of the United States set records for peak demand during the hot weather. Every RTO set records (see Table 4). Most strikingly, California's record was 10 percent higher than its previous peak, and that of PJM Interconnection LLC (PJM) was 8 percent higher (after correcting for PJM's expanded geographic footprint). Even with these higher peaks, however, overall electric usage in the United States during the summer rose by only 0.6 percent.

Table 4: New RTO Record Loads Set, 2006

Peak Loads				
RTO	Pre-06 (GW)	2006 (GW)	Increase %	2006 Peak Date
CAISO	45.4	50.3	10.7%	July 24
ERCOT	60.3	62.3	3.3%	August 17
SPP	40.5	42.2	4.2%	July 19
MISO	112.2	116.3	3.7%	July 31
PJM	133.8	144.6	8.1%	August 2
NYISO	32.1	33.9	5.6%	August 2
ISO-NE	26.9	28.1	4.5%	August 2

Source: Derived from RTO data, using hourly integrated peak loads.

Reliability and Emergency Actions

The U.S. bulk power system met the load requirements during the record-breaking heat. There were no blackouts at the wholesale level – though there were some severe distribution outages, especially in the St. Louis area and New York City. In all RTOs, administrative actions and other reliability actions were used to manage the loads.

Emergency Actions. Grid operators in all RTO regions made use of various administrative actions as well as market forces to ensure continuing service during the heat waves. These actions included issuing operational warnings, engaging in emergency transactions, and calling on demand response. Grid operators in California, PJM, New York, and New England cited two major factors in maintaining the bulk power system – demand response and unprecedented generator availability. Demand response was particularly important in several vulnerable regions – Long Island, southwest Connecticut, and California (see Table 5).¹⁶ Section 6, *Demand Response in Summer 2006*, discusses demand response in more detail.

Table 5: Demand Response in Vulnerable Regions, Summer 2006

Region	Peak Load		Demand Response	
	(MW)	Date	(MW)	(% of peak)
Long Island	5,684	August 2	261	4.6%
Southwest Connecticut	3,701	August 2	227	6.1%
California	50,270	July 24	2,066	4.1%

Source: Derived from RTO data and Connecticut Valley Exchange data.

16. The responses include distributed generation and conservation.

Importance of Preparation. During 2006's high-heat periods, grid operators responded best when they were prepared for the stress. When the grid operators were not as prepared, some problems arose. For example:

- New York faced its first hot weather during the week after Memorial Day. On May 30, NYISO went forward with a planned improvement to its real-time software, which took its real-time market offline for four hours during the first day of highly volatile prices, thereby eliminating the market during the period when it should, in theory, have been most valuable.
- In Texas, the Electric Reliability Council of Texas (ERCOT) ordered rolling blackouts on April 17 for about two hours. The Public Utility Commission of Texas faulted unseasonably high temperatures, a low demand forecast, large but normal planned generation outages (nearly 14,500 MW), and unplanned outages of 2,440 MW.

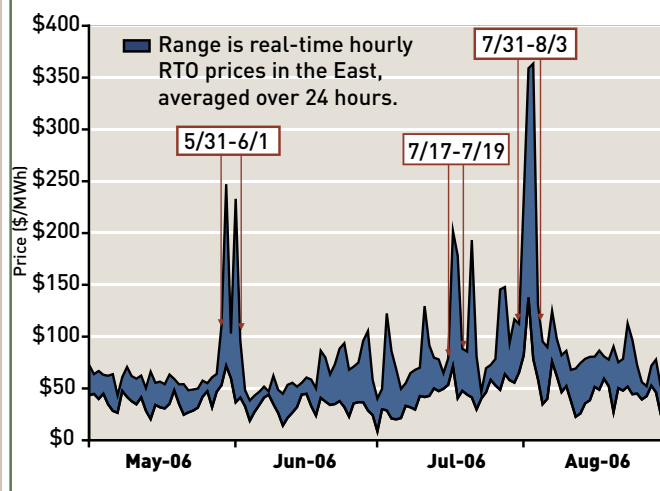
Prices During Hot Weather

Prices rose to very high levels at some times during the heat waves in both bilateral and RTO markets, as is typical for electric power markets. In eastern RTO markets, real-time prices rose dramatically during the heat waves (with the exception of July 21 when, even with cooler weather, a combination of unplanned outages and a thunderstorm alert drove prices in New York City higher), reflecting higher demands on the systems. Figure 13 shows the range of eastern RTO real-time prices during summer 2006.

Despite the long period of high temperatures during July 17-27, western U.S. prices reached very high levels only on July 24 (for July 25 delivery), power that traded during the day of highest regional peak demand. Day-ahead bilateral markets – which traded on Friday, July 21, for power use on Monday, July 24, did not anticipate the full severity of the demand. The WECC forecasted a peak demand for July 24 at 150.4 GW for the entire western region; the July 24 actual peak was actually 159.2 GW.¹⁷ Figure 14 shows the range of summer 2006 daily on-peak prices at western trading hubs.

Fig 13

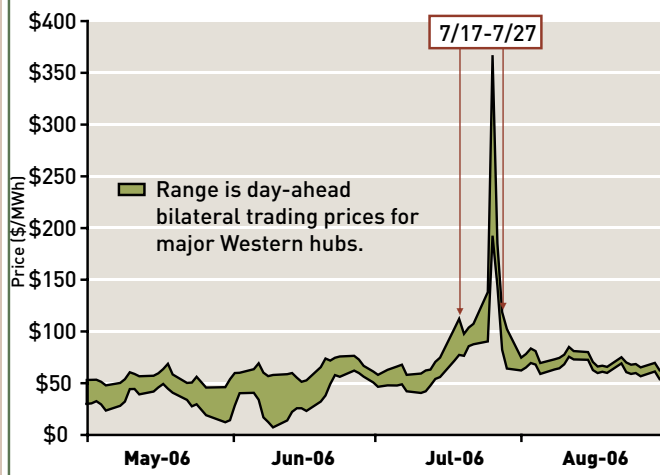
Real-Time Electric Prices in Eastern U.S. Markets, Summer 2006



Source: Derived from RTO data using ISO-NE Mass Hub, NYISO Zone J, PJM Western Hub, and MISO Cinergy Hub.

Fig 14

Day-Ahead Peak Electric Prices in Western U.S. Hubs, Summer 2006



Source: Derived from ICE data using COB, Four Corners, Mid-Columbia, Mona, NOB, NP-15, SP-15, and Palo Verde Hubs.

17. Western Electricity Coordinating Council, *Daily Reports*, July 21 and July 25, 2006.

Transactions above the \$400 Western Price Cap

A review of the Commission's Electric Quarterly Report (EQR) showed a small number of transactions in the West at prices above the applicable price or offer cap, representing less than 0.1% of all the power that flowed during the peak hour of that day. Unlike the \$1,000 offer cap in the East, the cap in the West is *soft* – the Commission can accept the prices or offers given adequate justification.¹⁸ About 70 percent of the apparently above-cap prices in the West through the summer occurred on the peak load date of July 24.

RTO Scarcity Pricing

During the summer heat, NYISO and ISO New England (ISO-NE) both invoked scarcity pricing (see Table 6). NYISO's scarcity pricing sets the clearing price at the higher of the locational price or the scarcity resource offer, based on an imputed demand curve. ISO-NE's version sets the clearing price at \$1,000/MWh.

MISO and PJM did not invoke scarcity pricing, though prices rose to very high levels in some locations. However, the MISO Independent Market Monitor reported that MISO avoided shortage conditions that would have resulted in prices at or near scarcity levels only because of the non-market emergency actions it took.¹⁹

Performance of Renewable Sources of Generation at the Peak

Renewables contributed to peak demands in different ways across the United States. In California, heat was combined with humid, stagnant air, resulting in low levels of wind generation. Averaged over the peak day, wind output was less than 15 percent of total wind capacity, contributing about 380 MW to the system.²⁰ In New York, almost 54 percent of wind generating capacity was produced on the peak day, contributing 149 MW.²¹ In the Midwest, almost two-thirds of wind generating capacity was used on the peak day, contributing 542 MW.²²

Table 6: Implementation of Scarcity Pricing in NYISO and ISO-NE, Summer 2006

Region/Date	Duration	Prices	Areas Affected
NYISO			
July 18	9 hours	\$500-\$1,000/MWh	Eastern zones
August 1	5 hours	\$500-\$1,500/MWh	New York City, Long Island
August 2	6 hours	\$500-\$1,500/MWh	Western zones, New York City, Long Island
August 3	6 hours	\$500-\$1,000/MWh	New York City, Long Island
ISO-NE			
August 1	2 hours	\$1,000/MWh	All zones, except Maine
August 2	5 hours	\$1,000/MWh	All zones

Source: Derived from RTO data.

18. *Cal. Indep. Sys. Operator Corp.*, 114 FERC ¶ 61,026, at 25-26 (2006) (raising the soft cap in WECC to \$400/MWh from \$250/MWh, but denying CAISO's request to make it a hard cap during the transition period to its MRTU).

19. David B. Patton, "Independent Market Monitor Review: 2006 Peak Load Event," PowerPoint presentation to the MISO Board of Directors Markets Committee, Sept. 20, 2006, p. 3.

20. Staff analysis of CAISO data.

21. Staff analysis of NYISO data. NYISO said unusual weather conditions on Aug. 2 contributed to this output. Averaged between 2 p.m. through 6 p.m. during June, July and August, wind production was 18.6 percent of capacity (Feb. 5, 2007, e-mail from NYISO to staff).

22. Staff analysis of MISO data.

CURRENT MARKET INSTITUTIONS

The largest regional difference in electric power market structure is between those regions that rely primarily on bilateral markets (the Southeast and the West outside California) and the rest of the country that relies largely on RTOs (see Table 7). RTOs operate the most influential markets for power (or imbalance energy in the case of CAISO, ERCOT, and SPP) in the regions they cover. In those regions, bilateral physical markets closely track analogous RTO markets, and financial instruments tend to settle against RTO markets, not bilateral markets. RTO markets provide far more information than other markets, especially about the locational value of the commodity.

In general, RTO and bilateral markets both produce prices that largely reflect the cost of fuel for marginal units.

Most RTO markets share some basic characteristics. Typically, they have day-ahead and real-time markets, based on security-constrained, optimal dispatch of generating units (CAISO, ERCOT, and SPP have no day-ahead market). The RTO markets have many differences of detail, but they are far more similar to each other than to the power markets in non-RTO regions.

Outside the RTOs, in the West, long-distance transmission and trading are essential for the entire region. Fairly deep and liquid bilateral spot markets exist both inside and outside California, especially for day-ahead power. These

Table 7: Wholesale Electric Markets in 2006

	■ Existing		□ Projected		Virtual Bidding (RTO/ISO)	Ancillary services markets (RTO/ISO)	Financial transmission rights (RTO/ISO)	Capacity (UCAP) markets (RTO/ISO)	Associated financial markets
	Real-time market		Day-ahead market						
	(RTO/ISO)	Bilateral	(RTO/ISO)	Bilateral					
New England	■	■	■	■	■	■	■	■ ¹	■
New York	■	■	■	■	■	■	■	■ ²	■
PJM	■	■	■	■	■	■	■	■ ³	■
Midwest	■	■	■	■	■	08	■		■
Southeast		■		■					■
SPP	■	■		■					
ERCOT	■	■	09	■		■	■		
Northwest		■		■					■
Southwest		■		■					■
California	■	■	08	■	09	■	■	4	■

¹ Transitioning to a formal capacity market. ISO-NE's installed capacity market was replaced on December 1, 2006, with the transition period for its new Forward Capacity Market.
² Locational
³ Systemwide
⁴ California is considering a formal capacity market.

Source: Staff analysis of RTO rules.

markets provide price discovery throughout the region, including for day-ahead transactions in California. In the Southeast, bilateral markets have few liquid trading points (into-Entergy is a partial exception) and little transparency.

The Commission initiated a series of conferences to examine competitiveness in electric power markets on December 19, 2006.²³ The conferences will explore many issues, including federal-state cooperation, the need for new infrastructure, demand response and renewable energy, the availability of long-term contracts, and market design issues affecting wholesale markets. The conferences will consider issues in all wholesale markets, both bilateral and within RTOs.

RTO DEVELOPMENTS

No new RTOs came into existence in 2005 or 2006, although MISO began operation of its energy market on April 1, 2005, and SPP inaugurated its imbalance markets on February 1, 2007.²⁴ Geographically, Duquesne Light joined PJM on January 1, 2005; Dominion Power joined PJM on May 1, 2005; and Louisville Gas & Electric and Kentucky Utilities withdrew from MISO on September 1, 2006. Most market characteristics in established RTOs remained stable (see Table 8). However, RTOs continued to evolve in several significant ways.

Three regions announced plans for major new market initiatives. As noted, SPP began its voluntary real-time locational marginal price (LMP) energy imbalance market on February 1, 2007.²⁵ CAISO currently intends to implement its “Market Redesign and Technology Upgrade” (MRTU) proposal in 2008.²⁶ The MRTU proposal includes a day-ahead energy market, LMP, co-optimization of energy and ancillary services, a backstop reliability commitment protocol, and redesigned transmission rights. ERCOT announced its intent to implement nodal pricing for generators by 2009 and raise its offer limit in stages to \$3,000/MWh for energy and \$3,000/MW for ancillary services.²⁷

Capacity Markets

Several RTOs have taken steps to encourage that investment in resources is adequate to meet peak demands in the future. To address that need, ISO-NE developed a new Forward Capacity Market (FCM).²⁸ ISO-NE will project the needs of the power system three years in advance and hold an annual auction to buy power resources to satisfy the needs. The first payments under FCM should begin in 2010-11. Similarly, the Commission acted on PJM’s proposed new Reliability Pricing Model (RPM) on December 21, 2006.²⁹ Several factors would affect pricing, including a sloped (assumed) curve for demand, location, and a forward commitment requirement for capacity.

23. *Commission Convenes Series of Public Conferences to Examine State of the Competitive Markets*, press release issued Dec. 19, 2006, available at: <http://www.ferc.gov/press-room/press-releases/2006/2006-4/12-19-06.asp>.

24. *Southwest Power Pool Inc.*, 118 FERC ¶ 61,055 (2007) (finding SPP’s Market Readiness Certification on its energy imbalance market in compliance with requirements of previous orders, and accepting SPP’s Certification filing).

25. *id.*

26. *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 (2006).

27. Texas Public Utility Commission, Project 26376, September 2003, included an order to ERCOT to develop a nodal market. ERCOT is running twelve concurrent projects to move toward its anticipated 3Q 2009 “Nodal Go Live.”

28. *Commission denies rehearing of New England’s Planned Forward Capacity Market; Proposed Tariff Accepted*, press release issued Nov. 1, 2006; *Devon Power LLC*, 115 FERC ¶ 61,340 (2006), *order on reh’g*, 117 FERC ¶ 61,133 (2006).

29. *PJM Interconnection L.L.C.*, 117 FERC ¶ 61,331 (2006) (denying rehearing and approving settlement subject to conditions).

Table 8: RTO Market Characteristics in 2006

Services Provided	■ Existing	□ Projected	◆ Cost-Based			● Other	
	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Bilateral transactions	■	■	■	■	■	■	■
Active online physical trading	■		■	■		■	■
Active online financial trading	■	■	■	■			■
Real-time energy market	■	■ ¹	■	■	■ ²	■	■
Locational energy price	■	■	■	■	■	■	■
Hourly energy price	■	■	■	■	■	■	■
Congestion price	■	■	■	■	■	■	■
Losses price	■	■	07 ³	■	■ ⁴	■	■ ⁵
Day-ahead energy market	■	■ ¹	■	■		09	08
Locational energy price	■	■	■	■		09	08
Hourly energy price	■	■	■	■		09 ⁶	08
Congestion price	■	■	■	■		09	■ ⁷
Losses price	■	■	07 ³	■			08
Ancillary services market	■	■	■	08	◆	■	■
Regulation service market	■	■	◆ ⁸	◆	◆	■	■
Operating reserves market	■	■	■ ⁹	◆ ¹⁰	◆	■	■
Reactive power market	● ¹¹	● ¹²	◆	◆	◆	◆	◆
Black start market		◆	◆	◆	◆	● ¹³	◆
Financial transmission rights	■	■	■	■		■	■ ⁷
Capacity market	■ ¹⁴	■	■			● ¹⁵	◆ ¹⁶
Regional transmission scheduling	■	■	■	■	■	■	■
Regional economic dispatch	■	■	■	■	■	■ ¹⁷	■ ¹⁷
Regional transmission planning	■	■	■	■	■	■	■
Regional interconnection process	■	■	■	■	■	■	■
Independent market monitor	■	■	■	■	■	■	■
Mitigation	■	■	■	■	■		■

¹ NYISO's Real Time Commitment model considers energy reserve and regulation when calculating prices.

² The SPP market is limited to an imbalance energy market.

³ Losses currently allocated to market participants based on a pro-rata share of total transmission losses. Marginal losses will be charged starting June '07.

⁴ Consumers also have the option to settle their losses by self-supply.

⁵ Allocated to sellers using generation meter multipliers, which reflect scaled marginal losses.

⁶ 15 minute settlement instead of hourly.

⁷ To be revised in 2008 under MRTU.

⁸ Offers from AEP and Dominion are cost-based, and all other are market-based.

⁹ Non-spinning reserves are derived from market-based offers.

¹⁰ Maintained by Balancing Authorities. When provided from generating resources, an hourly MW schedule for capacity is submitted to MISO.

¹¹ Participants capable of providing reactive power do not bid into the market. If called upon to provide this service, they are paid the energy clearing price if taken in merit or uplift if taken out of merit.

¹² Fixed monthly Mvar payment plus opportunity cost.

¹³ RFP procurement process.

¹⁴ ISO-NE's installed capacity market was replaced on December 1, 2006, with the transition period for its new Forward Capacity Market.

¹⁵ Replacement market buys generation for short term market to satisfy local congestion and system-wide capacity shortages.

¹⁶ CAISO has cost-based contracts for RMR. California is considering a formal capacity market.

¹⁷ No day-ahead energy markets; economic dispatch used in real-time balancing markets.

Source: Staff analysis of RTO rules.



Section 4

INFRASTRUCTURE OUTAGES AND THEIR EFFECTS ON ENERGY MARKETS

Even relatively small, isolated transportation network outages can have major effects on commodity pricing. In fact, one of the important characteristics of markets for natural gas and electric power is that they inherently signal tight infrastructure conditions with price changes.

In 2005 and 2006, energy markets provided numerous examples of prices signaling infrastructure constraints. In this section, we will consider constraints due to rail outages limiting coal deliveries to electric generators, hurricane damage to natural gas supply, pipeline capacity constraints on deliveries of natural gas from western Wyoming, and problems with electric supply into New York City and Long Island.

RAIL OUTAGES IMPAIR COAL SUPPLIES

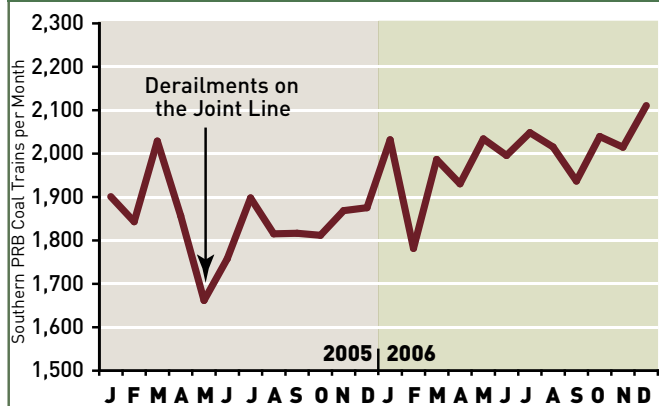
In 2005, major rail outages reduced deliveries of Wyoming's Powder River Basin (PRB) coal to electric generators. The resulting reductions in coal deliveries forced short-term changes in electricity markets and generation patterns. Over the longer term, markets responded as the railroads repaired damage and added new infrastructure, and customers devised ways to reduce their dependence on PRB coal.

PRB Coal and U.S. Electric Generation

Coal is the fuel for about half of all electric generation in the United States.³⁰ PRB coal accounted for about 34 percent of U.S. coal production in 2005.³¹ In May 2005, the rail

Fig 15

Coal Loadings Recover in 2006 After May 2005 Derailments



Source: Derived from Union Pacific and BNSF Railway Company data.

line leading south from the basin, the Joint Line, suffered two derailments, reducing the ability to deliver PRB coal to U.S. markets for more than a year (see Figure 15). In the short run, generators responded to the resulting disruptions by conserving coal, drawing down stockpiles, and importing more coal.

Concern by some market participants about coal logistics and electric reliability prompted congressional hearings from April through June 2006.³² The Commission hosted a June 15, 2006, discussion with utility and railroad representatives on the market and reliability issues related to the outage and coal transportation issues.³³

Recovery

By Fall 2006 the railroads had restored, and even augmented, delivery service from the basin. PRB carloadings set record highs in 2006. Union Pacific (UP) increased average trains per day out of the southern PRB by 7 percent, up from 32.8 trains per day in 2005 to 35.3 between 2005 and 2006.³⁴

Improved rail performance in 2006 coincided with, and may have been partially responsible for, several other coal industry developments. Wyoming coal production rose by 42 million tons, or 10.3 percent, in 2006 to 446 million tons.³⁵ Generators rebuilt their coal stocks. By the end of November 2006, electric power coal stocks reached 139.5 million tons, 31 percent more than a year earlier.³⁶ Over the longer run, coal customers have begun finding new ways to manage PRB supply risks including blending PRB coal with other coals, relying more heavily on imports, and switching to alternate coal supplies.³⁷

30. EIA, *Electric Power Annual 2005*, "Figure ES 1. U.S. Electric Power Industry Net Generation."

31. Platts *CoalDat*, September 2006 release.

32. The Senate Energy and Natural Resources Committee held hearings focused on coal supplies on May 25, 2006. The Senate Energy and Natural Resources Committee, subcommittee on surface transportation and merchant marine held a hearing on the economics, service, and capacity in the freight railroad industry on June 21, 2006. The House Transportation and Infrastructure Committee, subcommittee on railroads, held a hearing on railroad capacity on April 26, 2006.

33. *Discussions with Utility and Railroad Representatives on Market and Reliability Matters*, Docket No. AD06-8-000, June 15, 2006. Representatives from the major electric associations and railroads testified at this public meeting.

34. Derived from data on Union Pacific (UP) website: "UP Coal Loading Performance Data for the Powder River Basin," available at: <http://www.uprr.com/customers/energy/sprb/weekly.shtml> and "Updates Regarding UP Rail Service," available at: <http://www.uprr.com/customers/energy/sprb/updates.shtml>.

35. EIA, *Weekly and Monthly U.S. Coal Production Overview*, Dec. 30, 2006.

36. EIA, *Monthly Flash Estimates of Electric Power Data*, "Table 6.1 Trends in Total Fossil Fuel Stocks (Electric Power Sector)," Jan. 19, 2007.

37. Pace Global Energy Services LLC, *PRB Coal Transportation: Still a Hot Issue*, June 2006.

CONGESTION IN NATURAL GAS AND RESULTING EAST/WEST PRICE DIVERGENCE

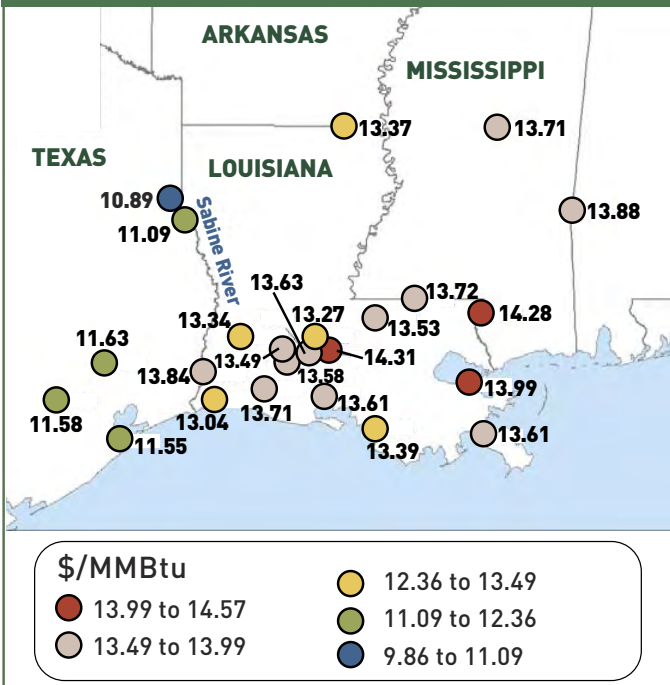
After hurricanes Katrina and Rita, gas supplies declined severely in Louisiana, and customers attempted to move supplies from East Texas into Louisiana for delivery farther east and north. The resulting congestion caused a large, persistent price difference between Texas and Louisiana. With returning production in Louisiana, price differences moderated.

The Sabine River Divide

After hurricanes Katrina and Rita, U.S. natural gas prices separated between East and West, with the most striking difference along the Sabine River boundary between Texas

Fig 16

Average Post-Hurricane Natural Gas Prices, October 8-14, 2005



Source: Derived from Platts data, using Platts PowerMap.

and Louisiana (see Figure 16). East of the Sabine River, in Louisiana, prices rose to as much as \$4/MMBtu higher than west of the Sabine River in Texas.

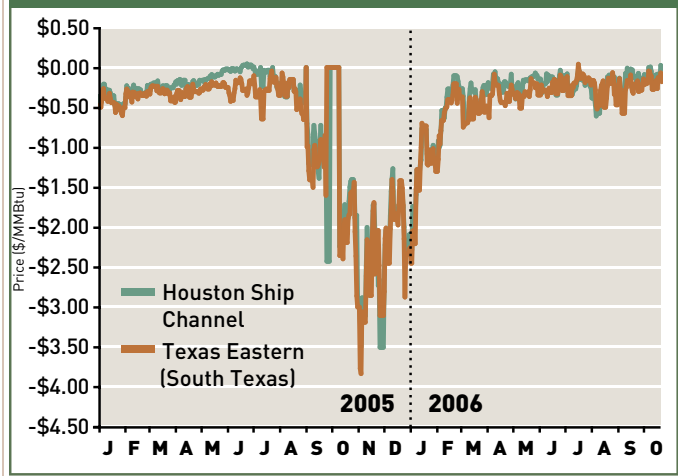
Historically, price differences from Texas into Louisiana were low through 2002 and grew somewhat after that. By 2004, the average price at Henry Hub was about \$0.15 higher than at Houston Ship Channel, largely because of increased production in Texas (e.g., Barnett Shale) and falling production in Louisiana.

Occasionally in the past, the price differences across the Sabine River boundary have risen for short periods of time. The differences after the hurricanes were larger and lasted much longer than in the past (see Figure 17) – enough to raise the average difference from the Houston Ship Channel to Henry Hub to \$0.78 for all of 2005, a five-fold increase from 2004.

The storms affected far more production and other infrastructure onshore and offshore in Louisiana than Texas. Customers from the East tried to move receipt points and buy as much Texas gas as they could to flow east. Once pipeline capacity was congested, prices between the two regions broke apart and stayed apart for several months.

Fig 17

Gap Between Texas and Henry Hub Prices Widened After Hurricanes



Source: Derived from ICE data.

Market Responses

Price differences between East Texas and Louisiana pricing points narrowed in 2006. In response to the continuing tightness of pipeline capacity heading east into Louisiana,

as well as the possibility of future hurricanes, pipeline companies proposed several projects for more capacity (see Table 9).³⁸

Table 9: Proposed Texas Natural Gas Infrastructure Projects

Developer	Project	Status	Date Filed With FERC	Date Final Approval by FERC	Year Scheduled for Service	Cost (Million \$)	Added Capacity (MMcfd)	Beginning State	Ending State
Gulf South Pipeline Co.	Gulf South Carthage to Keatchie Pipeline Loop	Applied	14-Apr-06	--	2006	47.9	122.4	TX	LA
Kinder Morgan Energy Partners	KMP Carthage Line	Announced	--	--	2007	50	700	TX	LA
Sabine Pipeline LLC	Sabine Henry Hub Expansion	Announced	--	--	2007	5	50	TX	LA
Gulf South Pipeline Co.	Gulf south Texas to Mississippi Expansion	Applied	01-Sep-06	--	2007	766.9	1,700	TX	MS
Trunkline Gas Co.	Trunkline north Texas 2007 Expansion	Applied	11-Sep-06	--	2007	159	510	TX	LA
CenterPoint Energy Gas Trans.	CEGT Perryville Expansion Phase 1 & 2	Approved	10-Mar-06	02-Oct-06	2007	404	1,237	TX	LA
CenterPoint Energy Gas Trans.	CEGT Perryville Expansion Phase 3	Applied	15-Dec-06	--	--	39	280	TX	LA
Boardwalk Pipeline Partners LP	Gulf Crossing Pipeline Project	Announced	--	--	2008	800	1,000	TX	LA
CenterPoint Energy Gas Trans.	CEGT Mid-Continent Crossing (MCX)	Announced	--	--	2008	2,000	1,750	TX	PA
Kinder Morgan Energy Partners	KMP Mid-Continent Express	Announced	--	--	2008	1,750	1,500	TX	AL
Nat Gas PL Co. of America	NGPL Louisiana/Gulf Coast Line Expansion	Applied	10-Oct-06	--	2008	66	200	TX	LA
Golden Pass LNG Terminal LP	Golden pass LNG Northern Line	Approved	26-Jul-04	30-Jun-05	2008	328	2,500	TX	LA
Port Arthur Pipeline LLP	Port Arthur LNG Laterals Phase 1	Approved	28-Feb-05	14-Jun-06	2008	217	3,000	TX	LA
Enbridge Energy Pipeline Co.	Enbridge TX-MS Pipeline	Announced	--	--	2009	400	1,000	TX	MS

Source: Staff analysis of FERC Office of Energy Projects data and EIA, *Pipeline Expansion Database*.

38. FERC's Office of Energy Projects provided the pipeline expansion data. About 6,000 MMcfd of capacity has been announced; 2,812 MMcfd has been applied for; and 6,737 MMcfd has been approved.

PIPELINE CAPACITY CONSTRAINTS FROM WESTERN WYOMING

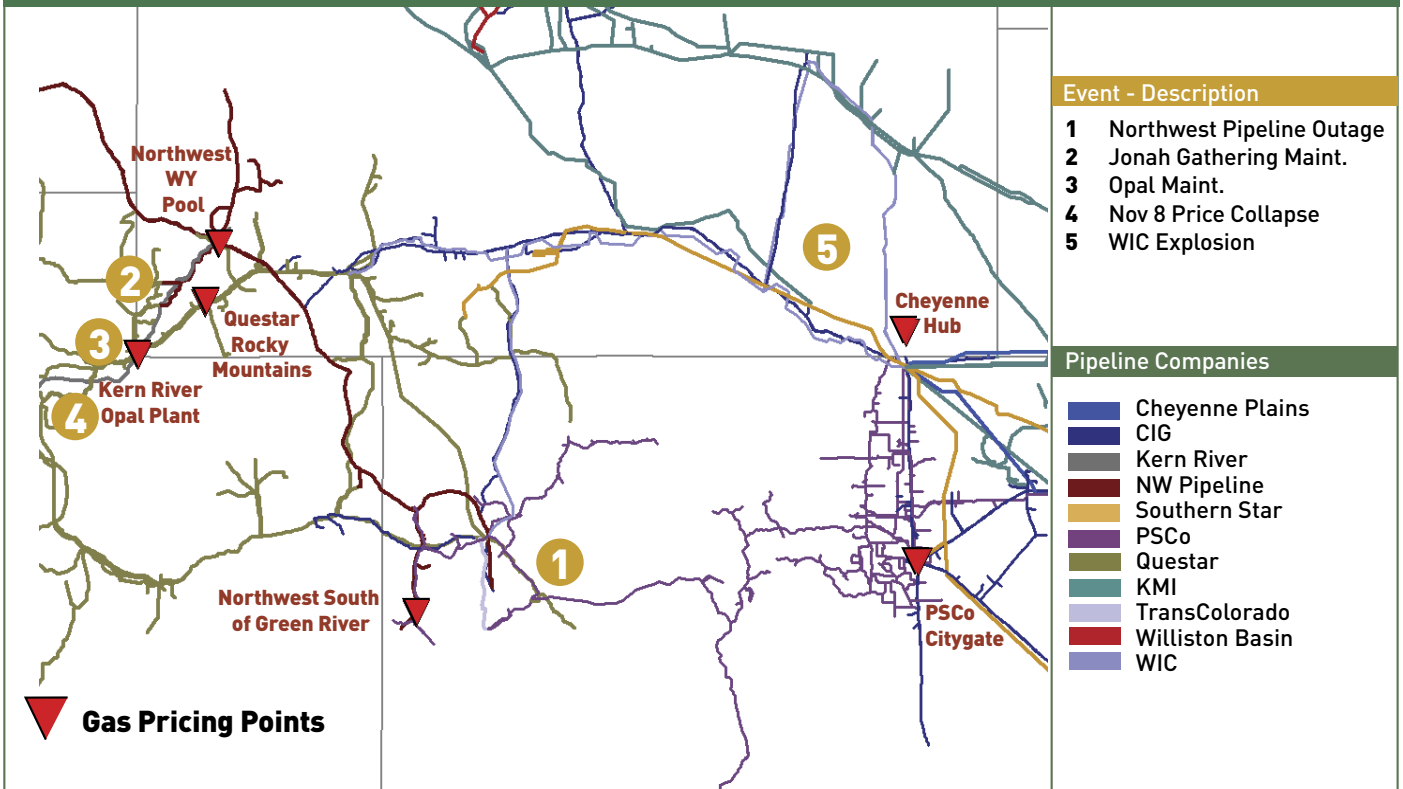
Lack of pipeline capacity to flow gas from western Wyoming to market was a chronic issue early in the present decade and often led to low prices in the area. (In a producing region, a shortage of capacity capable of moving the gas out, also called take-away capacity, can effectively create a local glut as too much gas is available for the available outlets to market.) During the last five years, the price disparity between western Wyoming and its major markets eased most of the time

because Kern River Pipeline and Cheyenne Plains Pipeline added capacity out of western Wyoming to both southern California and eastern markets (see Figure 18).

However, the balance between production and take-away capacity in the Rockies grew tighter, especially in 2006. Estimated daily gas supplied by key Rockies basins – Uinta-Piceance, Green River-Overthrust, Denver-Julesberg, and Powder River – increased by about 1 Bcf per day in 2006, while related take-away pipeline capacity was unchanged. As a result, on five occasions in Fall 2006, relatively small pipeline outages led to brief but severe price volatility in the area (see Figure 19).³⁹ Because the

Fig 18

Export Capacity from the Western Rockies, 2006



Source: Staff analysis of Bentek Energy data, created using Platts PowerMap.

39. The gathering system outage would have the opposite effect of pipeline outage because it reduced supplies available to be taken to market.

outages were relatively small (especially in the context of the wider western market), the outages had no major effect on prices in major market areas.

- **September 14-19.** Planned maintenance on the southern leg of Northwest Pipeline curtailed gas taken from Wyoming and Colorado to markets in Arizona and California. The outage totaled 350 MMcf. All other pipelines were full. Western Wyoming prices fell by an average of \$2.16/MMBtu for four days. (See Event 1 on Figure 18)
- **October 4-5.** Planned maintenance on the Jonah Gathering system reduced receipts into pipelines by 272 MMcf. The relative shortage of gas for two days led to a noticeable price increase. (See Event 2 in Figure 18)
- **October 6-9.** Planned outage at the Opal, Wyoming, plant on Kern River Pipeline reduced take-away capacity by 210 MMcf, about 3 percent of total capacity. All remaining pipeline capacity was full. Prices fell an average of \$2.96/MMBtu. (See Event 3 on Figure 18)

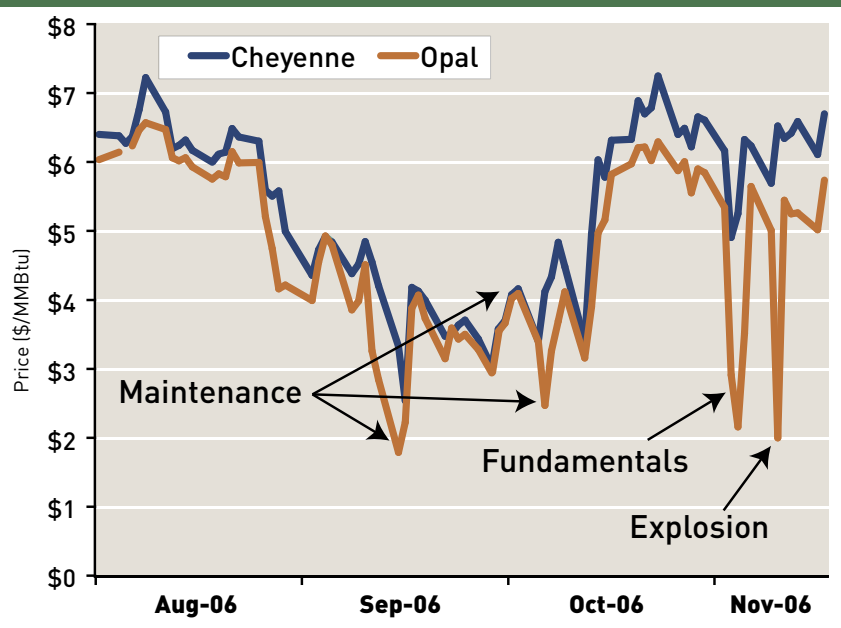
- **November 8.** Pacific Gas & Electric issued a high inventory operational flow order; there was too much gas on its system relative to light gas demand. Reduced California gas requirements coupled with limited ability for new local Rockies storage, contributed to a 150 MMcf reduction in throughput on the Kern River Pipeline. (See Event 4 on Figure 18)
- **November 11.** An accident on Wyoming Interstate Company (WIC) reduced gas flows by 765 MMcf. Prices fell by an average of \$3.26/MMBtu at western Rockies points. (See Event 5 on Figure 18)

Market Response

Market participants recognized the need for more pipeline capacity leaving western Wyoming. About 3 Bcf of incremental pipeline capacity is in various stages of development, with about 1.7 Bcf approved and under construction.

Fig 19

Maintenance Affects Wyoming Gas Prices, 2006



Source: Derived from ICE data and Bentek Energy pipeline notices.

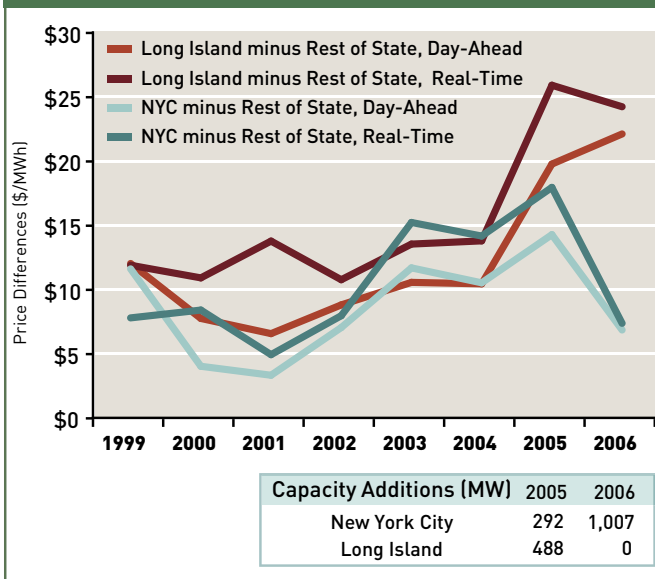
ELECTRIC POWER ISSUES: NEW YORK CITY AND LONG ISLAND

Traditionally, New York City and Long Island have had the highest power prices in the NYISO. From 2000 through 2005, the differences between the two areas and the rest of New York grew at roughly the same rate. In 2006, the price differences between New York City and the rest of the state declined considerably, while the difference between Long Island and other areas continued to grow (see Figure 20).

The largest change between 2006 and 2005 affecting relative prices between New York City and Long Island was the addition of generating capacity in New York City (see Figure 20, inset).⁴⁰ Between the peak summer seasons of 2005 and 2006, New York City added 1,299 MW of capacity, about 14 percent of the previous total. By contrast, Long Island added only 488 MW (9 percent of previous capacity).⁴¹ Adding capacity in New York City appears to have improved the balance of supply and demand in the City, putting downward pressure on prices. Indeed, on one day during 2006, New York City faced transmission constraints on sending power north out of the city for the first time ever.⁴² Increased generation in the city also helped it weather a major transmission

Fig 20

Large Generation Additions Reduced New York City Price Premium, Summer 2006



Source: Derived from NYISO data.

outage during the summer. With the new generation, New York City was able to manage a series of outages on two 345-kV transmission lines serving New York City starting in June and continuing through July 17.⁴³ During the July heat wave, New York City did experience local distribution outages that affected 25,000 customers in northwest Queens.⁴⁴

40. Prices in New York City and Long Island reflect several factors besides relative supply and demand in the two areas – for example, losses, price mitigation in New York City, and scarcity pricing in both areas. Capacity additions include generation and transmission.

41. The Cross Sound Cable was energized in 2005, although it had previously been in place.

42. Monthly Staff conference call with NYISO, June 7, 2006.

43. The outages probably did not contribute to the change in relative prices between New York City and Long Island. They would have tended to worsen the supply-demand balance in the city, putting upward pressure on prices there.

44. Consolidated Edison, "Initial Report on the Power Outages in Northwest Queens in July 2006," Aug. 2, 2006.



Section 5

INCREASING INTERDEPENDENCE AMONG ENERGY MARKETS

In 2005 and 2006, U.S. physical energy markets became more integrated, both among themselves and with global energy markets. Although we tend to consider energy markets as distinct (e.g., electricity or gas), they increasingly influence one other. Key areas of integration evident in 2006 included natural gas and electric markets, natural gas and oil markets, and global LNG markets.

KEY AREAS OF INTEGRATION

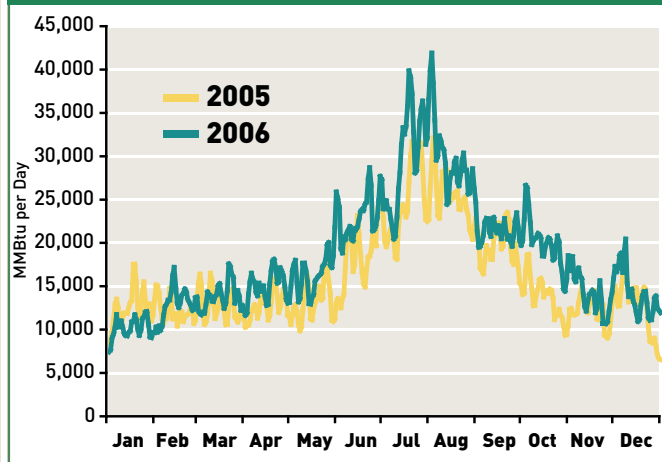
- **Natural gas and electric markets.** Natural gas is a major fuel for the electric industry, and natural gas prices often set electric power prices because gas-fired plants are the marginal units in many areas. Further, reliability during stressful periods requires strong integration between the market operations of the two industries.
- **Natural gas and oil markets.** Despite the fact that regional natural gas prices moved below competing fuel oil prices in some regions and decreased the demand for oil, high global oil prices may be preventing U.S. natural gas prices from dropping further. Changing dynamics in international fuel markets, however, may alter the traditional oil-natural gas pricing relationships.
- **Global LNG markets.** In 2006, imports of LNG into North America fell, as LNG moved from the Atlantic Basin to more attractive markets in India and East Asia. This trend expands competition for global natural gas beyond that observed between Europe and North America in previous reports.⁴⁵ Indeed, global LNG markets may be surpassing oil in influence on U.S. natural gas markets.

NATURAL GAS AND ELECTRIC MARKETS

Power generators used 19.2 Bcf of natural gas per day through November 2006, up 6.2 percent from 2005.⁴⁶ Estimates of daily natural gas deliveries to power generators peaked on August 2, 2006, at nearly 42 Bcf – 31 percent more than the 2005 peak of 32 Bcf on August 3, 2005 (see Figure 21).

Fig 21

Estimated Natural Gas Delivered to U.S. Power Plants, 2005-06



Source: Derived from Bentek Energy, Supply/Demand Balance data.

Importance of Coordination in Electric and Gas Operations

Given the importance of natural gas in electric generation – in terms of its size and its role as a marginal electric fuel – integration of market operations between the two industries becomes critical during periods of system stress.

45. Federal Energy Regulatory Commission (FERC), *2004 State of the Markets Report* (Washington, DC: 2005) (2004 SOM).

46. EIA, *Monthly Flash Estimates of Electric Power Data*, "Table 5.1 Trends in Fossil Fuel Consumption for Electric Generation, Total (All Sectors)," Jan. 19, 2007.

Three incidents, two from 2004 and one in 2006, illustrate the point:

- **New England (January 2004).** Sustained record cold weather hit New England and eastern Canada from January 14 through January 17, 2004.⁴⁷ Intraday gas prices reached \$75/MMBtu. Some gas-fired generators sold their natural gas – instead of using it to fuel power generation – and then declared economic outages, leading to a reserves shortage and almost to a blackout. Differences in power and gas scheduling created uncertainty for generators about relative prices.
- **San Diego Gas and Electric (November 2004).** On November 19, 2004, Unit 2 (1,122 MW) at the San Onofre Nuclear Generating Station in California unexpectedly tripped (or became unavailable). Unit 3 was already unavailable.⁴⁸ The reduced electric supply increased demand for natural gas generation in the San Diego area, straining San Diego Gas and Electric's (SDG&E) gas distribution capabilities. The situation was further exacerbated when, on November 22, 2004, a control valve slammed shut on one of SDG&E's main gas supply lines and further reduced the pressure on the line. When the weather also turned cold, increased gas demand in SDG&E almost forced curtailment of electric generation, which could have led to rolling blackouts. Indeed, California may have the most dramatic need for coordination between electric and gas markets since that state's stringent air quality restrictions effectively eliminate potential fuel switching to oil when natural gas supplies are low.
- **Public Service Company of Colorado (February 2006).** On February 18, 2006, Public Service Company of Colorado (PSCo) imposed a rolling blackout affecting 300,000 customers between 8:48 a.m. and 10:18 a.m. Temperatures fell as low as minus-13 degrees Fahrenheit, 15 degrees colder than forecasted. Heating demand for

gas coupled with growing electric needs exceeded the gas supplies PSCo had nominated, reducing line pressure on PSCo's gas distribution system and shutting down some gas-fired plants.⁴⁹

ISO-NE's response to its 2004 incident was an important first initiative in addressing electric/gas coordination issues. ISO-NE fostered better communications with interstate natural gas pipelines and generators about operating conditions and devised new cold weather operating procedures. It developed better information about the ability of units to respond to emergency conditions and relaxed its \$1,000/MWh offer price cap during emergencies to permit generators to recover higher gas costs.

ISO-NE's improved coordination has helped harmonize scheduling and pricing between the natural gas and electric industries in New England. Deadlines for day-ahead offers and subsequent scheduling confirmations vary significantly among the RTOs (see Table 10).

Table 10: Timeline for Day-Ahead Power Offers by RTOs in 2006

RTO	Day-Ahead Offers Due	Notification	Notes
ISO-NE	Noon	Re-offer between 4:00 to 6:00 p.m.	ISO-NE may invoke "Cold Weather Event" and move day-ahead offer deadline to 9:00 a.m.
MISO	11:00 a.m.	4:00 p.m.	Re-offers accepted from 4:00 to 5:00 p.m.
NYISO	5:00 a.m.	11:00 a.m.	No re-offer or emergency provisions (about 95% of market clears day-ahead)
PJM	Noon	4:00 p.m.	Re-offer between 4:00 and 6:00 p.m.
SPP	N/A*	N/A	N/A
ERCOT	N/A*	N/A	N/A
CAISO	N/A*	N/A	N/A

* No day-ahead market
Source: Staff analysis of RTO rules.

47. 2004 SOM, p. 13-24.

48. San Onofre Unit 3 was unavailable due to refueling. San Onofre Unit 1 was permanently shut in 1992 for decommissioning.

49. *Investigation of Controlled Outages of Feb. 18, 2006, by the Public Service of Colorado*, Docket No. 06L-118E6, Colorado Public Service Commission, Jul. 7, 2006.

By contrast, time windows for buying day-ahead physical natural gas are similar across the country. Most market participants buy physical natural gas between 9:00 and 11:00 a.m. the day before the natural gas flows. The relative uniformity resulted from several years of collaboration by gas industry market participants to craft standards (promulgated by the North American Energy Standards Board and its predecessor, the Gas Industry Standards Board) to implement the nominations and scheduling aspects of FERC Order Nos. 636 and 637. Interstate (and often intrastate) pipeline tariffs now incorporate these standards by reference.

The Commission's Response

The Commission responded to the power scheduling uncertainties on October 25, 2006, stating that the:

Commission is concerned that the scheduling practices of independent system operators (ISOs) and regional transmission organizations (RTOs) are not effectively coordinated with the scheduling of natural gas purchase and transportation transactions, so that gas-fired must-run generators may be unable to obtain gas during periods when gas transportation is constrained or gas prices are volatile. To address these issues, the Commission will institute inquiries pursuant to section 206 of the Federal Power Act (FPA) in the above referenced dockets to provide the parties in ISOs and RTOs with forums in which to examine whether scheduling and compensation mechanisms need to be revised to ensure that gas-fired generators can obtain gas when the gas-fired generation is necessary for reliability and that they are compensated appropriately when volatility in gas prices creates difficulty in recovering gas costs. Each of the RTOs and ISOs above must make a filing by January 16, 2007, either proposing necessary changes to their scheduling and compensation systems or explaining why such changes are unnecessary.⁵⁰

Also on October 25, 2006, the Commission issued a Notice of Proposed Rulemaking to incorporate by reference proposals to add another intraday gas cycle with bumping rights, change energy timelines in RTOs so that electric markets can clear within existing gas nomination periods, and require generators that bid into day-ahead markets to have enough gas to run if called.⁵¹

NATURAL GAS AND OIL MARKETS

In recent years, natural gas prices have depended largely on storage levels and the world price of oil (see Figure 22), in addition to weather and development and exploration costs. The ratio of natural gas prices to oil prices can change based on storage levels, with gas prices rising compared to oil when storage levels are low. The results since 2001 show that relatively low storage levels correspond with high gas prices. When storage inventories are high, however, gas prices fall compared to oil to a level that looks fairly consistent over time. In effect, it appears that gas prices do not fall much further than to a ratio of about 0.43 to oil prices (with both priced on a common Btu basis), a level that has been much in evidence in late 2006. Conversely, in times of shortage, the ratio of natural gas to oil prices rarely exceeds 2.0.⁵²

More specifically, the results of 2005 and 2006 show that:

- **Natural gas prices** have risen quite high when market participants are unusually fearful about the adequacy of natural gas supplies. Gas prices for the post-hurricane period in 2005 were consistently higher than previous experience with similar storage levels would have

50. *Order Instituting Inquiries into Gas-Electric Coordination Issues*, 117 FERC ¶ 61,094 (2006), 1.

51. *Standards for Business Practices for Interstate Natural Gas Pipelines and Standards for Business Practices for Public Utilities*, Notice of Proposed Rulemaking, 117 FERC ¶ 61,095 (2006).

52. The weekly deviation from average storage inventories on the X axis of Figure 22 is based on the average of storage inventories from 2001 to 2005, rather than 2006, which was an atypical year.

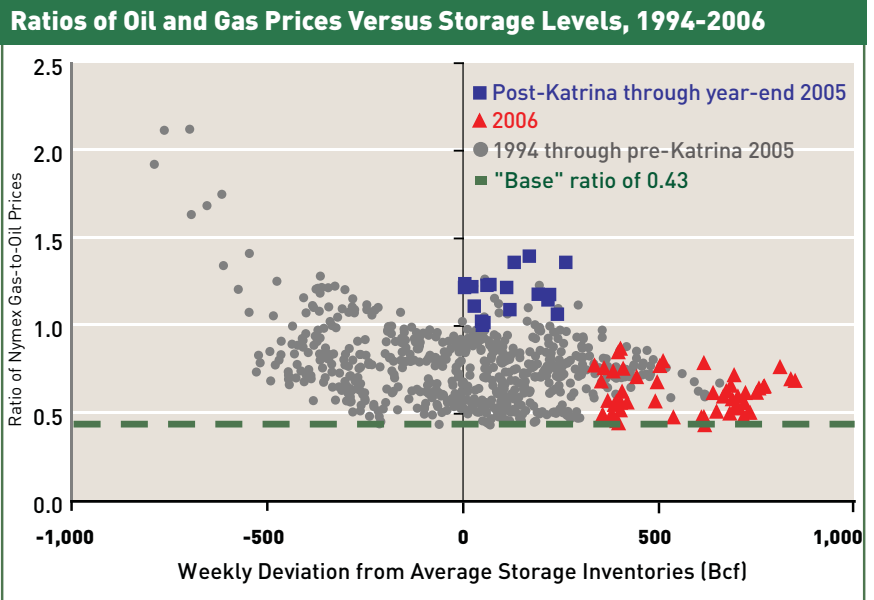
suggested. The unusually high prices reflected the fear of many gas customers that a cold winter and lower production levels could lead to shortages. Local distribution companies that hedged their positions at unusually high prices appeared to be acting sensibly under the circumstances – they could not have known that January 2006 would be the warmest on record and that husbanding of gas supplies would prove unnecessary.⁵³

- **World oil prices** tended to support natural gas prices despite record levels of storage. During 2006, gas storage levels were much higher than in recent years, but overall gas prices remained about the same compared to oil as in other years. In effect, world oil prices appear to have prevented North American gas prices from falling further. This dynamic may reflect a global connection between natural gas and petroleum prices that affects the United States even where LNG is a small part of overall supply.

Competition with Residual Fuel Oil in Some Markets

Although world oil prices apparently prevented a steeper drop in U.S. natural gas prices, gas prices did drop enough that natural gas could and did displace residual fuel oil in certain markets. For example, for several years, natural gas prices in the Northeast have ranged between a floor set by residual (No. 6) fuel oil prices and a ceiling set by distillate (No. 2) fuel oil prices,

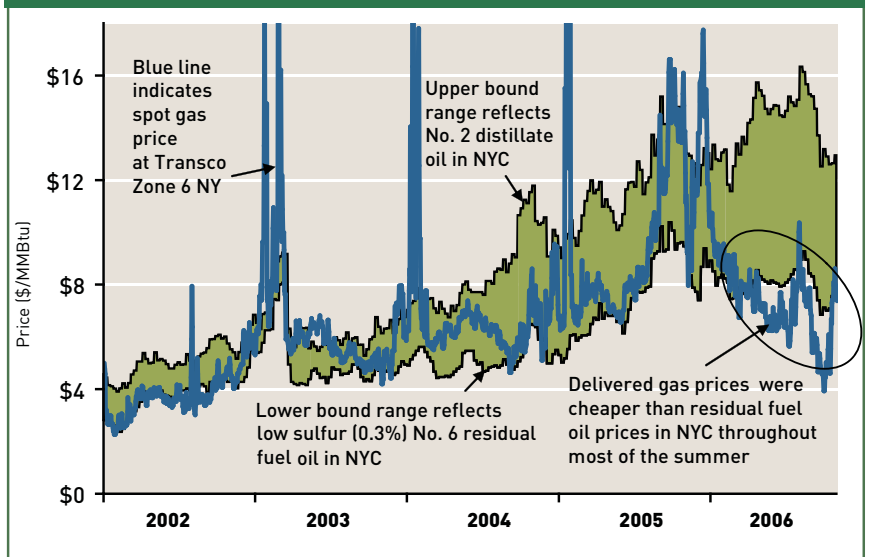
Fig 22



Source: Staff analysis of EIA *Weekly Natural Gas Storage Report* and Nymex data.

Fig 23

Gas and Fuel Oil Prices in New York City, 2002-06



Source: Derived from Bloomberg data.

53. In fact, it is critical that local distribution companies in early winter protect storage inventories and rely more heavily on spot gas – even if the prices are unattractive. Storage functions as a vital insurance policy for U.S. energy markets through the winter. Interestingly this crucial behavior is, in effect, indistinguishable from speculators buying in a tight market in the hope of higher prices, and necessarily has the same effect on overall market prices.

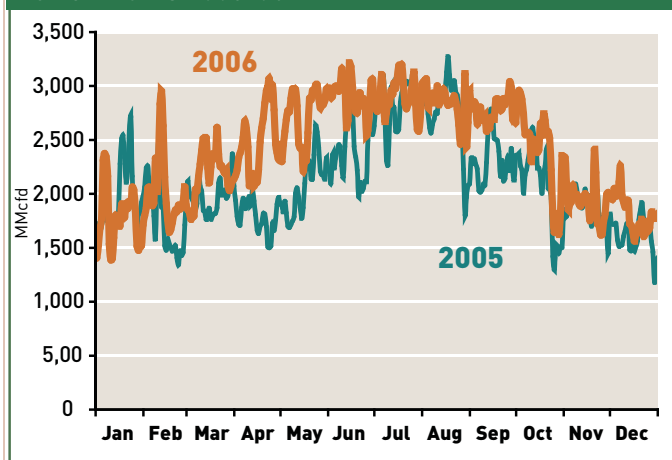
except during brief weather-driven price increases (see Figure 23). Beginning in March 2006, the price of delivered natural gas in New York fell below that of competing low sulfur residual fuel oil and remained there for many months. The last time natural gas prices fell below those of residual fuel oil for a significant period in the Northeast was in 2002. In 2006, the natural gas price fell further below the residual fuel oil price for a longer time.

The low natural gas price compared to fuel oil strongly affected fuel use. Through October 2006, EIA reported, the electric power sector burned less than half as much oil as in 2005, while gas usage rose about 5 percent.⁵⁴

More competitive gas prices affected generation fuel mixes most in Florida, New York, and New England. In Florida, gas use grew significantly during summer 2006 (see Figure 24). Florida accounts for about 25 percent, or 246 MMcfd, of the estimated average monthly dual-fuel residual plant capability in the United States.⁵⁵

Fig 24

Daily Natural Gas Deliveries to Florida Power Plants 2005-06



Source: Derived from Bentek Energy data.

GLOBAL LNG MARKETS

Global LNG supplies are crucial to the energy future of the United States. Economic growth, increasing use of natural gas for electric power generation and the growing use of natural gas for oil recovery in Canada will all add extra demand that domestic supply is unlikely to meet. As a result, increased capability to import LNG remains a central part of the country's ability to address its energy challenges. Planned investment in new LNG terminal capacity continued during 2006 as market participants continued to see the importance of increased imports in the future.

In the short term, LNG deliveries declined somewhat in both 2005 and 2006 for reasons that were peculiar to the two years. In 2005, the decrease was partly due to the logistical problems of delivering LNG in the wake of the hurricanes. Deliveries to Lake Charles, Louisiana, were down by 60 Bcf, while deliveries to other terminals increased by 39 Bcf. In 2006, the mild winter and storage overhang reduced relative U.S. prices and consequently the immediate demand for LNG.

In addition, the experience of 2005 and 2006 made clear that LNG markets are global, with increasing activity in Asia as well as Europe.

Imports Down in 2006

In 2006, North America saw an unusual combination of a warm winter, high storage inventories and falling natural gas prices. As a result, LNG imports into the United States fell by 8 percent, or 49 Bcf, in 2006,⁵⁷ after falling 3 percent, or 21 Bcf, in 2005 (see Table 11). Rising 2006 imports to terminals at Lake Charles, Louisiana; Elba Island, Georgia; and Everett, Massachusetts, did not fully offset a 105 Bcf decline at Cove Point, Maryland.

54. EIA, *Monthly Flash Estimates of Electric Power Data*, Dec. 21, 2006.

55. Kenneth L. Yeasting for CERA, *Dual Fuel Steam Generation: Alive and Well*, Nov. 20, 2006.

56. Florida gas deliveries reflect scheduled, intra-day 2 natural gas volumes on Gulfstream Natural Gas System at Station 100 and at Florida Gas Transmission Compressor Station 11 at Mount Vernon.

57. Final 2006 import totals by terminal were not published as of this writing; 2006 values are estimates.

Table 11: Annual U.S. LNG Imports by Terminal, 2004-06 (Bcf)

	2004	2005	2006	2005-2004		2006-2005	
				Change	% Change	% Change	% Change
Cove Point	209	222	116	12	6%	-106	-48%
Elba Island	105	132	146	27	26%	14	11%
Energy Bridge	0	5	0	5	N/A	-5	-91%
Everett	174	169	176	(5)	-3%	7	4%
Lake Charles	164	104	144	(60)	-37%	40	39%
Total	652	631	582	(21)	-3%	-49	-8%

Source: Derived from EIA U.S. Natural Gas Imports by Country, and The U.S. Waterborne LNG Report data.

Investment Remains Strong

The recent declines in LNG imports are likely to be temporary. Over the long term, falling natural gas production and increasing natural gas demand in North America will require increased reliance on imported LNG. Interest in developing LNG infrastructure in North America remains strong. Key developments in 2006 included:

- **Excelerate Energy and Suez LNG** have both received the approval of the governor of Massachusetts to site two terminals with capacities of 800 MMcfd and 750 MMcfd, respectively, in the waters offshore of Boston; state environmental permits are pending. In addition, the Suez LNG proposal received a federal deepwater port license from the U.S. Maritimes Administration.
- **Canaport**, sponsored by Repsol and Irving Oil, obtained project financing in October for a regasification plant to interconnect with the Maritimes & Northeast Pipeline in New Brunswick and serve the northeastern United States. The imports would replace lower-than-expected offshore production from Sable Island.
- **Energía Costa Azul**, Sempra's Baja California project, is more than 67% complete. Commercial operations are set to begin in early 2008 with an initial capacity of 1 Bcf.⁵⁸

Competition with Europe

In 2006, Europe remained the primary alternative to the United States for deliveries of Atlantic Basin LNG. European gas markets had relatively few liquid, or greatly used, pricing points – the key ones were the National Balancing Point (NBP) in the United Kingdom and Zeebrugge in Belgium. Prices at NBP and Zeebrugge tended to track each other because of a direct pipeline connection between the two. Both points showed lower prices than in other European markets, such as Spain, where many LNG prices were linked to oil prices or buyers who were willing to pay almost any price for LNG because they could average these costs with cheaper supplies into the rates they charge their customers.

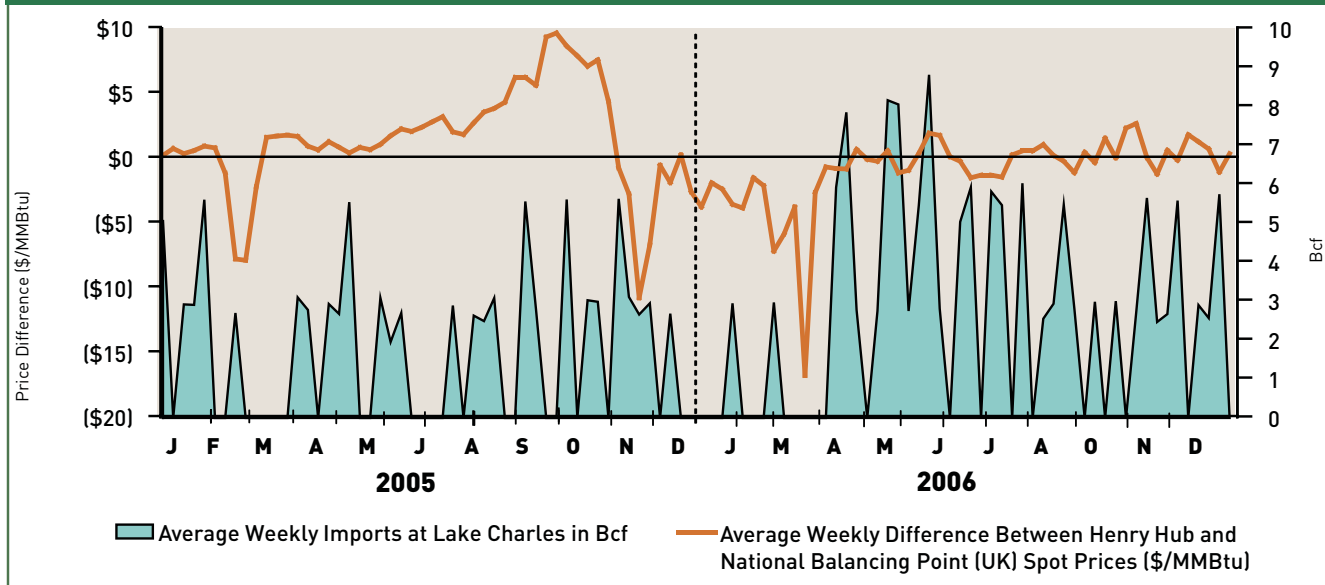
NBP prices have tended to be higher than Henry Hub in the winter and similar or lower in the summer, partly reflecting the scarcity of storage in Western Europe. However, when Henry Hub prices increased in fall 2005 because of hurricanes Katrina and Rita, they reached much higher levels than at NBP (see Figure 25).

NBP prices also show two significant dips in 2006 due to the opening of new pipeline connections. In some cases, intraday prices actually went negative when the Langede Pipeline connected the United Kingdom to Norwegian gas supplies via the Sleipner riser facility.

58. Dale Kelly-Cochrane for Sempra LNG, *Energia Costa Azul LNG Terminal & Pipeline Status Report*, [California] Governor's LNG Task Force Briefing, Jan. 18, 2007.

Fig 25

LNG Imports Respond to U.S. and UK Price Differences, 2005-06



Source: Derived from Bloomberg; DOE, *Natural Gas Imports and Exports*, DOE, *LNG Imports: Monthly Report*; and *The U.S. Waterborne LNG Report* data.

During 2005 and 2006, deliveries to Lake Charles responded to major price disparities between Europe and North America when it was physically feasible to do so. Lake Charles imports dropped to (or remained at) very low levels on the three occasions when European prices rose far above Henry Hub prices. On the one occasion when Henry Hub prices were noticeably higher than European prices, imports into Louisiana were difficult because of hurricane damage and, thus, import volumes did not rise significantly.

Increased Deliveries to Asia

A key development in 2006 in global natural gas markets was the increased importance of Asian purchasers for Atlantic Basin LNG (see Figure 26). Market participants sold about 112 Bcf of spot LNG from Egypt, Algeria, Nigeria, and

Trinidad, or “west of Suez,” to customers in the Far East from April through December 2006.⁵⁹ They sold almost no such gas before 2006.⁶⁰

Floating Storage

Competitive markets – increasingly including global LNG spot markets – innovate where necessary. The LNG industry depends on three capital intensive types of investment: liquefaction facilities in producing countries, LNG tankers, and plants that regasify in receiving countries. At any time, the three investment streams are likely to be somewhat out of phase with each other. During 2006, for example, there was a relative glut of tankers compared to liquefaction capacity.⁶¹

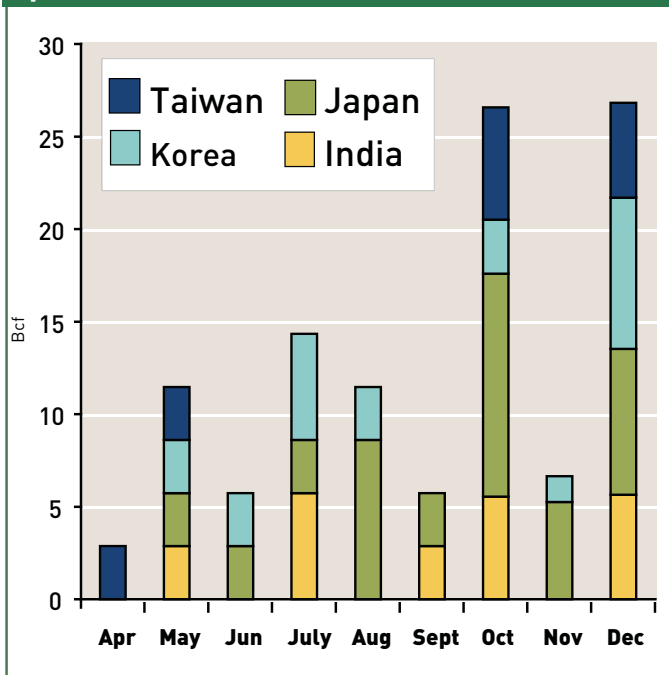
59. *The U.S. Waterborne LNG Report*, Dec. 20, 2006.

60. Staff telephone call with Steve Johnson, Waterborne Energy, Dec. 21, 2006.

61. *Ibid.*

Fig 26

Atlantic Basin LNG Sold to Asian Buyers, April-December 2006



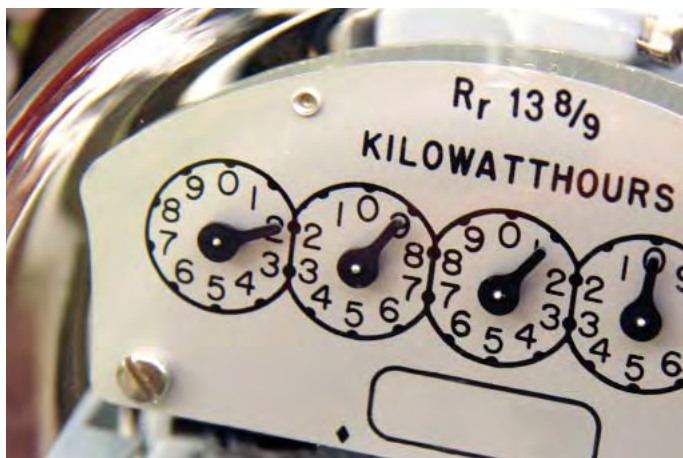
Source: Derived from *The U.S. Waterborne LNG Report* data.

Market participants responded to this imbalance by creating so-called floating storage. Shippers took advantage of large seasonal differences in summer and winter gas prices (winter gas was greater than \$4/MMBtu more than summer gas at Henry Hub) by holding LNG for several months in at least 16 tankers. These ships discharged up to 45 Bcf of gas, some purchased as early as June 2006, in November and December. One company (Excelerate Energy) devised a way to transfer LNG from ship to ship, allowing it to consolidate cargoes to minimize the gas that evaporates from each tanker.

Of the 16 tankers waiting in mid-ocean in the middle of November, 13 discharged loads by mid-December:

- Six to Asia, India and the Far East;
- Three to Europe: two to Spain and one to Zeebrugge;
- Four to North America: two to Lake Charles, one to Elba Island and one to Altamira; and
- As of late December, three were still at sea: one off Malta, one in the Caribbean, and one off South Asia.⁶²

62. *The U.S. Waterborne LNG Report*, Dec. 20, 2006.



Section 6

DEMAND RESPONSE IN SUMMER 2006

Demand response played a key role in meeting peak needs across the United States during stressful periods in summer 2006.

In two of the most electrically vulnerable areas of the United States – Long Island and southwest Connecticut – demand response appeared to have reduced peak load by significant amounts, as much as 4.6 percent and 6.1 percent of peak load, respectively. In these areas, demand response may have made a decisive contribution to avoiding blackouts.

DEMAND RESPONSE

Demand response⁶³ as practiced in today's RTO markets consists of many separate programs, including:

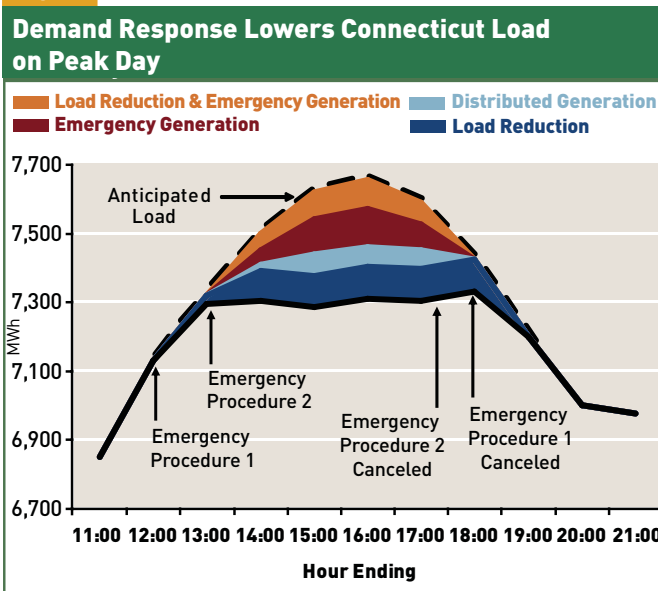
- **Reliability-based programs** that include both voluntary emergency programs that compensate respondents when they curtail during an emergency and capacity programs that curtail customers in exchange for a payment or rate discount;
- **Economic programs** that allow participants to submit load reduction bids into day-ahead and real-time markets;
- **Time-based rates**, such as time-of-use rates and real-time pricing;
- **Legacy utility programs**, such as interruptible tariffs or direct load control that contribute to system reliability; and
- **Calls for voluntary conservation** without direct economic benefit to the customer.

These programs formed a patchwork of initiatives to reduce system loads at peaks. They had different sponsors – state governments, utilities, and the RTOs themselves. Demand-response programs had different rules and rationales, depended on different payment mechanisms, and appealed to different customer motivations. Most had little or no direct connection to spot market forces. Nonetheless, in aggregate during summer 2006, they delivered benefits by reducing demand on the system at the times of most stress.

Connecticut provides a good example of how demand response worked in summer 2006. Reliability-based real-time interruptible resources comprising four programs and four resource types were called on to reduce the peak

load on the peak day of August 2, 2006 (see Figure 27). Demand resources appeared to eliminate demand growth through the afternoon of that day, a time when demand would normally grow considerably. Demand response appeared to produce similar patterns in all of the eastern RTOs.

Fig 27



Source: Derived from preliminary ISO-NE data.

Reliability Based resources: Load reduction; Distributed generation: customer sited generation; Emergency generation: backup generators with permits to run in limited circumstances; Load Reduction & Emergency Generation: facilities using a combination of load reduction and emergency generators.

ISO-NE Actions. Emergency Procedure 1 (OP-4, Action 9): reserve shortage conditions; interrupt 30-minute demand resources that do not require voltage reduction. These customers have guaranteed they will respond, and receive capacity payments; Emergency Procedure 2 (OP-4, Action 12): Further actions to maintain 10-minute reserve; interrupt 30-minute demand resources that require a voltage reduction.

63. Demand response usually refers both to reductions or interruptions in load as well as to the use of generating units that are on a customer's site – distributed generation. Both reduce the stress on grid resources.

Table 12: Demand Response Effects in RTOs on Peak-Demand Days, Summer 2006

RTO/Region	Peak Day	Peak Day Demand Response			Price Effect
	Date	(MW)	(MW)	% of Peak	(est. \$/MWh)
ISO-NE	August 2	28,127	496	1.7%	None
SW CT	August 2	3,701	227	6.1%	
NYISO	August 2	33,879	1,139	3.5%	Unknown
NYC	August 2	11,347	429	3.8%	
Long Island	August 2	5,684	261	4.6%	
PJM	August 2	145,951	N/A	1.4%	\$300
Mid-Atlantic	August 2	62,017	2,050	3.3%	
MISO*	July 31	136,250	1,096	0.9%	\$100-200
CAISO	July 24	50,270	2,066	4.1%	Unknown

* MISO's peak demand response occurred on August 1, though the peak load was on July 31.

Source: Derived from preliminary RTO data.

The variety of demand-response programs made it hard to measure their effects on system peak in aggregate. Nevertheless, the best estimates from the RTOs all showed demand reductions associated with demand response in each region on or near peak-demand days in 2006 (see Table 12).

Price effects differed among the RTOs. MISO estimated that demand response lowered prices by \$100-\$200/MWh.⁶⁴ PJM estimated the price reduction to be \$300/MWh.⁶⁵ In New England, by contrast, demand-response programs had no price effect because they were dispatched only when scarcity pricing also was in effect; scarcity pricing in New England sets the relevant prices at \$1,000/MWh. In New York, the interaction of demand response and demand-curve driven scarcity pricing was difficult to assess. Reliability-based demand response in New York can set the market price when dispatched, and is part of NYISO scarcity pricing procedures.

Demand Response and Markets

Most demand-response programs in RTO regions during summer 2006 had little or no direct connection to the operation of RTO markets and market-clearing price formation. Some – voluntary reductions – amounted to a willingness on the part of customers to reduce demand for no payment. Other customers curtailed their consumption when directed by system operators. These customers were either under interruptible rates that provide rate discounts in exchange for a customer's obligation to curtail, or capacity programs that provide a guaranteed payment (typically based on prevailing capacity market prices) to customers who curtail when directed. These programs represent an option the customer had previously sold prior to the real-time market, and are generally set by various forms of regulation, not by market forces.

Though impossible to separate the effects, most utilities and RTOs invoked demand-response programs to preserve

64. Phone interview between OE staff and the Midwest Independent System Operator.

65. PJM news release, Aug. 17, 2006, and phone interview between OE staff and Andy Ott, PJM vice president of markets, August 2006.

reliability, not to affect markets.⁶⁶ As a result, some observers interpreted the resulting demand response as being unrelated to markets.

For example, MISO's independent market monitor reported that invoking emergency measures reduced demand enough to prevent the imposition of scarcity pricing.⁶⁷ In his view, demand response "had the effect of depressing the price signals that should occur during shortage and near-shortage conditions."⁶⁸ More than two-thirds of the demand response came from interruptible load, for which customers had already received lower rates, and responses to appeals for conservation, in which customers responded even with a direct price of effectively zero.⁶⁹

Specific RTO Experiences

Specific information available about demand response differs from region to region. Among the highlights:

ISO-NE. ISO-NE called for demand response on two days, but activated all reliability programs only on August 2.⁷⁰ Almost half of all demand response reported by ISO-NE

came from southwest Connecticut, the most constrained area. About 75 percent came from Connecticut as a whole. Much of the rest came from Maine, the least constrained area. ISO-NE demand response appeared to be about equally split between load reduction and emergency or distributed generation.

NYISO. NYISO called on demand-response resources on five days, July 18-19 and August 1-3.⁷¹ On the peak day, August 2, demand reduction totaled 1,189 MW statewide.⁷² Demand response from economic programs was small where it mattered most – New York City and Long Island programs account for only 15 MW.⁷³ On August 2, NYISO exported 1,300 MW of emergency energy to New England during one key afternoon hour and called on resources in western New York zones to provide voltage support for sales to PJM.⁷⁴ The PJM sales would not have been possible without demand response.⁷⁵

PJM. PJM invoked its "Full Emergency Load Response" programs on August 2 and 3, but not its Energy Only (voluntary economic) program; some load-serving entities

66. CAISO directed California investor-owned utilities to activate their interruptible programs and reduce load only on the third peak day; based on CAISO peak day conference calls with Commission Staff (including California IOUs, municipal utilities, the Governor's Office, and other state agencies), July 24 and 25, 2006. MISO, "Midwest ISO 2006 Load Management Response Survey, Summary, Jan. 5, 2007," and "Summer 2006 Review: Presentation to the Midwest ISO Board of Directors – Markets Committee," Sept. 20, 2006. PJM: Email correspondence between Craig Glazer, PJM Interconnection, and Commission Staff, Sept. 13, 2006. NYISO, *NYISO 2006 Demand Response Programs*, semiannual demand response report to the Commission, Jan. 16, 2007. A notable exception was the Aug. 2 activation of the Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) in three western New York zones to support scheduled market sales to PJM; on the same day, 1,300 MW of emergency energy was sold to ISO-NE, which was in a 5% voltage reduction state (p. 11). ISO-NE: "New England Demand Response: Summer 2006," September 2006.

67. David B. Patton, "Independent Market Monitor Review: 2006 Peak Load Event," PowerPoint presentation to the Markets Committee, MISO Board of Directors, Sept. 20, 2006.

68. Patton, Sept. 30, 2006, 3.

69. The Midwest ISO "2006 Load Management Response Survey, Jan. 5, 2007 Summary" (emailed to staff) reported that on Aug. 1, total demand reduction was 2,651 MW. The three largest contributing categories were: interruptible loads (1,387 MW or 52%), public appeals (465 MW, 17.5%), and behind-the-meter generation (375 MW, 14%).

70. "New England Demand Response: Summer 2006," September 2006.

71. NYISO, "Operations and Market Performance: Summer 2006," draft for discussion (Power Point presentation prepared for monthly staff conference call on Sept. 13, 2006).

72. NYISO, "Operations and Market Performance." A subsequent call between Commission and NYISO staff (Dec. 14, 2006) made it clear that calculating actual responses is complicated by delays in data submission as well as the Customer Base Line (CBL) methodology used to compute the reductions. More detailed information was in the *NYISO 2006 Demand Response Programs*, semiannual demand response report to the Commission, Jan. 16, 2007, 13-14.

73. David J. Lawrence, "NYISO's Demand Response Programs," PowerPoint presentation at New York Market Orientation Course (NYMOC), November 2006.

74. Monthly conference call between Commission and NYISO staff, Aug. 2, 2006.

75. *Ibid.*

(LSEs) invoked local programs more widely.⁷⁶ PJM estimated that almost half of the overall reduction came from LSE programs in the Mid-Atlantic control area.⁷⁷ PJM also estimated total savings to the system of \$650 million for the week, of which \$230 million was saved on August 2 alone.⁷⁸

MISO. MISO invoked emergency measures between July 31 and August 2,⁷⁹ and many Midwestern utilities invoked their own demand-response programs during the heat wave.⁸⁰ MISO does not operate reliability-based or economic demand-response programs as do other ISOs.⁸¹ Its estimates of demand response were therefore uncertain, prompting it to undertake a survey of its demand resources, sent to balancing authorities and utilities.⁸²

CAISO. During the time of system peak, California relied on a combination of reliability-based demand response programs operated by utilities and voluntary load curtailments. California relied heavily on voluntary load reductions, augmented by the governor's call for a 25 percent reduction in power use at state agencies, none of which compensates customers for curtailing use.⁸³ CAISO estimated initially that conservation cut demand by about 1,500 MW daily during their heat wave, during which the peak day occurred.⁸⁴ CAISO asked utilities to activate interruptible load programs only once, on July 24, the peak day.⁸⁵ Demand reductions were also achieved from the Demand Reserves Partnership, a program that allows third-party participation and aggregation.

76. E-mail correspondence between PJM Interconnection staff (Craig Glazer and Susan Covino, Demand Response Manager) and Staff, Sept. 13, 2006, and subsequent phone conversations with PJM staff.

77. *Ibid.*

78. PJM news release, Aug. 17, 2006, and subsequent phone interview between OE staff and Andy Ott, PJM vice president of markets, August 2006.

79. Many facts on MISO-wide responses in this section are derived from "Independent Market Monitor Review: 2006 Peak Load Event," presented to Board of Directors Markets Committee, by David B. Patton, Potomac Economics, Sept. 20, 2006, and "Midwest ISO Summer 2006 Review and Discussion," Sept. 6, 2006, Carmel, Ind.

80. Multiple news reports during heat wave.

81. MISO, "The Current Role of Demand Response in Midwest ISO Spot Energy Markets," Nov. 7, 2006, *available at* http://www.midwestmarket.org/publish/Document/3c9065_10e9e96031d_-7f7a0a48324a?rev=1.

82. MISO, "Summer 2006 Review Et Discussion," Sept. 26, 2006; and "Midwest ISO 2006 Load Management Response Survey, Summary, Jan. 5, 2007," e-mailed to staff.

83. A full accounting of the amount of demand response on July 24 in the CAISO has proven difficult. No agency or entity in California has summarized or cataloged the level of demand response from all sources. Some data are based on OE staff interviews with CAISO staff, Dec. 11-12, 2006. CAISO announced 18 days of "power watch" in 2006 compared to seven in 2005. A "power watch" is an alert posted on its Web site as a day-ahead warning that the ISO will need conservation on the following day, accompanied by a news release. Summary *available at*: <http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls>. CAISO issued press releases calling for conservation on July 13, 17-18, 24-26; CAISO issued a press release touting conservation's contribution, Aug. 1, 2006.

84. CAISO press releases, July through August 2006; staff interviews with CAISO, December 2006.

85. Staff monthly conference call with CAISO, Jul. 27, 2006, and Lawrence Berkeley National Laboratory analysis of CEC data filed by utilities, e-mailed to staff, Dec. 11, 2006.



Section 7

GROWING INFLUENCE OF FUTURES AND FINANCIAL ENERGY MARKETS

North American futures and financial energy markets continued to attract interest from investors in 2005 and 2006. Though no single measure of activity exists for futures and financial energy trading, several measures document that overall activity increased. Of particular interest to observers of physical energy markets was an apparent increase in the interdependence of cash physical with futures and financial markets. Additionally, futures and financial energy markets came under greater scrutiny in 2006 as some public officials (in particular) expressed concern about the role of speculation in energy markets.

REPORTS RAISE CONCERNS ABOUT ENERGY SPECULATION

During 2006, three highly publicized reports argued that speculators drove North American natural gas prices higher than they would have been otherwise:

- **The Midwest Attorneys General** presented a study of natural gas prices in March that concluded, among other things, that customers were being “overcharged” \$5 billion per month as a result of too-high gas prices.⁸⁶ Commission staff raised significant methodological concerns about the report.⁸⁷
- **The U.S. Senate’s** permanent subcommittee on investigations, Committee on Homeland Security and Governmental Affairs, released a study in June that concluded, “The traditional forces of supply and demand cannot fully account for these increases [that is, in oil and gas prices from 2000 through 2006].”⁸⁸ It also concluded that increasing futures prices due to speculation would raise spot prices.⁸⁹
- **The National Legal and Policy Center** concluded in August that “high natural gas prices of the last five years and current prices for natural gas futures likely reflect other factors, including the structure of the market, speculation not based on economic fundamentals, and perhaps price manipulation.”⁹⁰ It also concluded that “natural gas prices diverge from economic fundamentals even more in the futures market than in the spot markets.”⁹¹

THE ROLE OF SPECULATION

Despite the sometimes pejorative connotation of the term, *speculation* is a normal and necessary part of all markets. Speculation is the buying or selling of an interest in a commodity for the purpose of benefiting from an expected (or hoped for) future value of that commodity. A robust market depends on a wide variety of conflicting perspectives about current and future market conditions to reach workably competitive levels. Otherwise, there is no basis for trading. For example, buyers and sellers would largely lose the benefits of hedging if there were no speculators willing to assume the risks that hedgers want to lay off.

It is also important to note that the rising price of natural gas in North America was anything but unique, considering recent price trends and the possible role of speculation and other forms of investment in energy price movement. The United Nations reported that global prices for all basic commodities, including natural gas and petroleum, rose between 2001 and late 2005 largely because of global economic growth.⁹² One effect of such a commodity boom was to encourage the flow of financial assets into commodity markets. Goldman Sachs estimated that investment in global commodities grew from less than \$10 billion in 2001 to more than \$50 billion in 2005, with about two-thirds of it in the Goldman Sachs Commodity Index fund (GSCI).⁹³ The GSCI invested 10 percent to 12 percent of its funds in natural gas and 56

86. Mark N. Cooper, for the Midwest Attorneys General Natural Gas Working Group (Illinois, Iowa, Missouri, Wisconsin), *The Role of Supply, Demand, and Financial Commodity Markets in the Natural Gas Price Spiral*, March 2006, 6.

87. Transcript of Mar. 16, 2006 Commission meeting, 31-60, *available at*: <http://www.ferc.gov/EventCalendar/Files/20060324072947-transcript.pdf>.

88. U.S. Senate Permanent Subcommittee on Investigations, Committee on Homeland Security and Governmental Affairs, *The Role of Market Speculation in Rising Oil and Gas Prices: A Need to Put the Cop Back on the Beat*, Washington, D.C., Jun. 27, 2006, 1.

89. *Ibid*, 16, fn. 36.

90. Robert J. Shapiro and Nam D. Pham, *An Analysis of Spot and Futures Prices for Natural Gas: The Roles of Economic Fundamentals, Market Structure, Speculation, and Manipulation*, August 2006. Work conducted by Sonecon, LLC and supported by a grant from the National Legal and Policy Center, 1.

91. *Ibid*, 16.

92. United Nations Conference on Trade and Development, *Trade and Development, 2006* (New York and Geneva, August 2006).

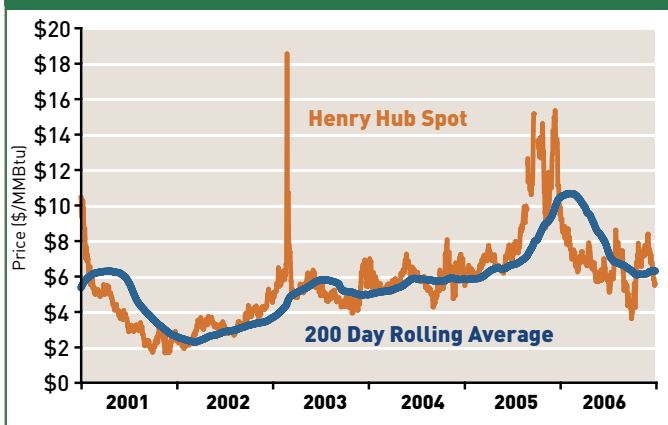
93. Goldman Sachs & Co., “The Goldman Sachs Commodity Index [GSCI]”, PowerPoint presentation of the GSCI New York Team and the GSCI London Team, May 2005, 3.

percent to 64 percent in petroleum products (including crude oil) between 2003 and 2006.⁹⁴

To illustrate why that consistent, sustained growth made sense to investors, the price of natural gas remained above its 200-day moving average most of the time for almost four years from early 2002 through late 2005 (see Figure 28). Under those conditions, from the perspective of an investor (who, in this context would behave similarly to a speculator), buying a financial interest in natural gas (as well as a variety of other basic commodities) proved a good investment over the whole period, regardless of any direct physical interest in the commodity itself. Those kinds of returns, particularly contrasted to returns available broadly in stock markets, clearly attracted investment capital. Goldman Sachs said that investors in the GSCI include “pension funds, foundations and endowments, high net worth individuals, insurance companies, asset managers, hedge funds, [and] private banks” in more than 20 countries.⁹⁵

Fig 28

Henry Hub Spot Natural Gas Prices Relative to 200-day Rolling Average, 2001-06



Source: Derived from Platts data.

Speculation and Other Price Movement Strategies

Though we tend to speak of speculation as if it were a single strategic approach to investment, it actually reflects a broad array of strategies. Speculators in well-developed financial energy markets can and do bet that almost every set of prices might go up or down, and different speculators bet in opposite directions for the same set of prices. Over the past few years, staff has noted apparent speculation in both directions in many cases.

Though not exactly the same as speculation, commodity index trading may play a similar role in futures and financial markets. Investors include those, such as pension funds and individuals, who invest in the energy sector as part of an overall portfolio, without trading actively in the short term. In effect, over the past few years, these investors might have followed this logic: “Global growth is increasing demand for all sorts of commodities; I want to invest in a basket of such commodities in the expectation that their prices will rise.” Investment in the GSCI, for example, is commodity index trading.

By contrast, active speculation includes those that may trade actively in the short term, like many energy trading companies, investment banks, and hedge funds. In the case of hedge funds, falling natural gas prices apparently led to two major collapses in 2006:

- **MotherRock, L.P.**, a \$400 million energy hedge fund founded by former Nymex President Robert “Bo” Collins, failed at the end of July. After reporting 20 percent gains in 2005, MotherRock, which had borrowed money to increase its position in natural gas futures and over-the-counter swaps, lost all its own value and cost its prime broker, ABN-Amro, an estimated additional \$60-\$100 million as natural gas prices fell.⁹⁶

94. Goldman Sachs & Co., “Goldman Sachs Announces 2007 Weights for the Goldman Sachs Commodity Index”, press release, Nov. 6, 2006. Goldman Sachs anticipated lowering its weighting for natural gas in 2007 to less than 8%. Standard and Poors recently announced it would purchase the GSCI.

95. Goldman, Sachs & Co., “The GSCI,” p. 10.

96. “MotherRock Cries Uncle,” Aug. 3, 2006, www.thestreet.com; “Energy Hedge Fund Closes Shop,” Aug. 4, 2006, www.CNNMoney.com.

- **Amaranth Advisors, LLC**, a multistrategy hedge fund, collapsed in September, suffering the largest loss ever by a hedge fund. Most reports say that Amaranth lost \$5-\$7 billion.⁹⁷ Unlike MotherRock, Amaranth had enough investment to meet all of its margin calls, and it subsequently sold its energy portfolio to others. As a result, it posed no systemic credit risk to the markets.

DEVELOPMENTS IN FUTURES AND FINANCIAL ENERGY MARKETS

Coinciding with increased capital inflows, futures and financial energy markets appeared to become significantly more active in recent years. Together, futures and financial energy markets comprise many venues, ranging from well-known, highly organized exchanges for standardized futures and options contracts on one end of the spectrum to a wide variety of much less standard, less well-understood bilateral agreements among active market participants on the other. As a result, there are no comprehensive measures of these types of energy market activity. Instead, observers must use the information that is available from various parts of the market as indicators of overall trends in the markets. Most available indicators come from the more standardized, transparent parts of the market. Less transparent parts of the market may well have grown more (or less) rapidly than the visible indicators suggest.

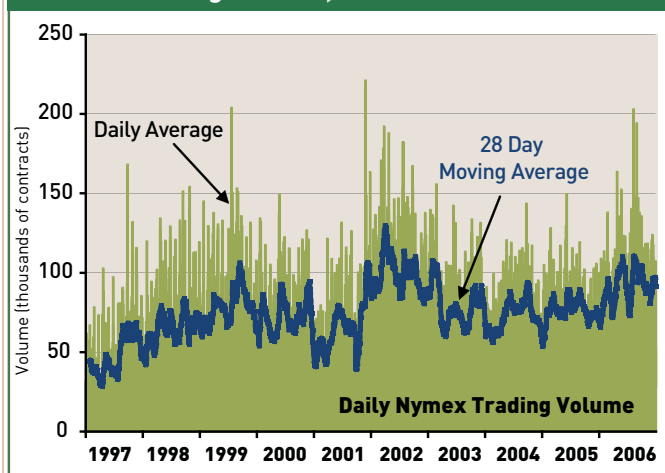
Available indicators show that participants in the futures and financial markets traded greater volumes, showed more willingness to hold on to sales or purchase commitments, and developed new ways to trade. Such markets also appeared to influence some cash physical markets. Increased activity was particularly apparent in visible natural gas markets, but affected electric power markets as well.

Volume of Natural Gas Futures Traded Has Increased

Volumes traded for the Nymex natural gas futures contract – measured by the number of contracts bought and sold on any particular day – more than doubled over the past decade (see Figure 29).

Fig 29

Natural Gas Futures Contract Trading Volume Recovered to High Levels, 2006



Source: Derived from Nymex data.

Willingness to Hold Gas Futures Positions (Open Interest) Increased More Rapidly

Nymex reports the overall willingness of its participants to hold positions to sell or buy futures using a measure called *open interest*. Open interest is the total number of futures contracts sold or bought (they total the same number) but not yet liquidated by offsetting transactions or delivered. Open interest rose much more rapidly than overall trading, especially since 2005 (see Figure 30). Specific changes in this measure indicate some important trends:

- **Longer-term open interest grew**, particularly for dates more than a year into the future. In effect, participants

97. "A Hedge Fund's Loss Rattles Nerves," Sept. 19, 2006 and "Hedge Fund Shifts to Salvage Mode; Amaranth Trying to Shed Gas Portfolio," Sept. 20, 2006, by Gretchen Morgenson and Jenny Anderson, *The New York Times*; "Blue Flameout: How Giant Bets on Natural Gas Sank Brash Hedge-Fund Trader," Ann Davis, Sept. 19, 2006, *The Wall Street Journal*; "Amaranth - How to Lose \$5.0 Billion without Even Trying," By Cal Payne, Sept. 25, 2006, IssueAlert@UtiliPoint.com.

became more willing to take positions further out in time. Increased activity in these longer-term markets could have been valuable for those who wanted to hedge periods longer than a year, as well as for those who wanted to speculate.

- **Shorter-term open interest also grew substantially.** This growth underscores the overall success of the natural gas futures exchange in attracting activity, both speculative and hedging. Since financial trading takes place in different markets than Nymex futures trading, the level of Nymex futures open interest inherently understates the collective activity in futures and financial markets. With the growth of other related financial instruments that use futures prices to set their value, and even sometimes directly mimic Nymex gas futures on other trading platforms, active participants

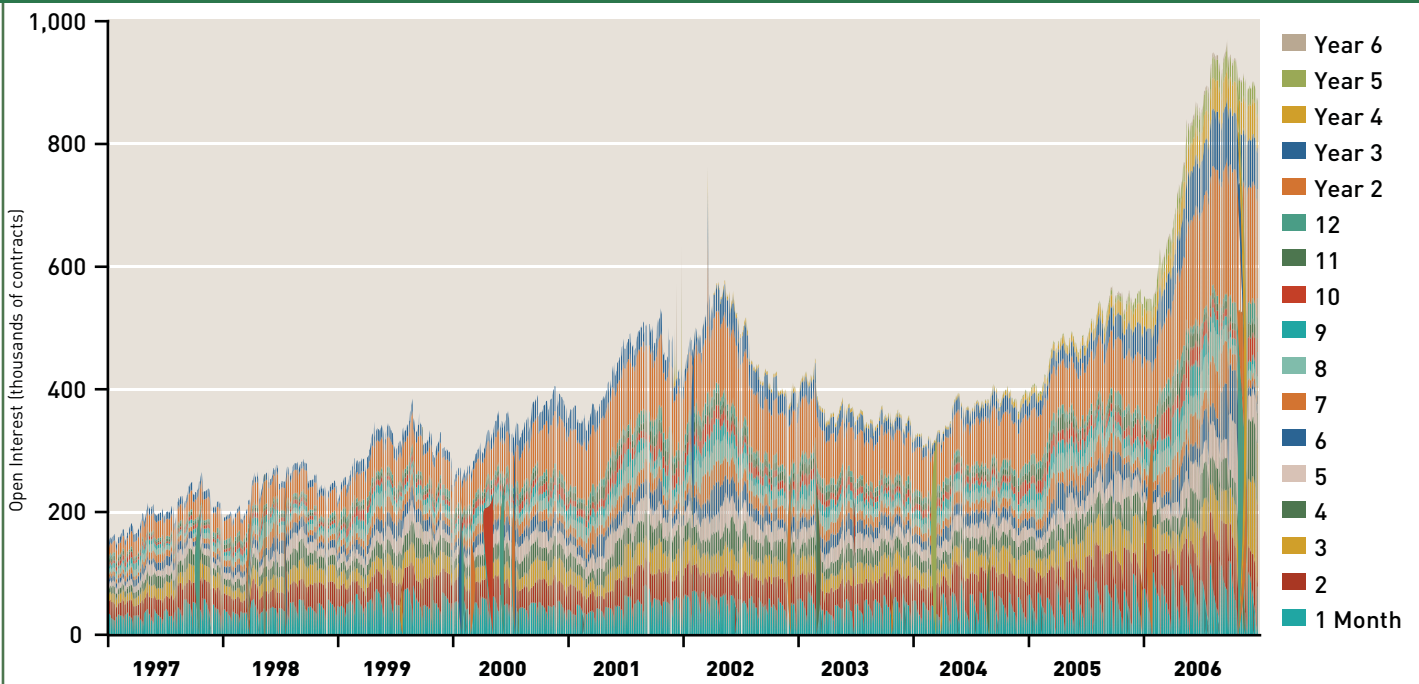
can and apparently do develop much larger positions than are apparent on Nymex alone.

Electronic Trading of Nymex Gas Futures Now Competes with Pit Trading

Historically, futures trading occurred in a pit where designated trading representatives gathered and traded with each other. Nymex gas futures continue to use pit trading. Beginning on September 5, 2006, Nymex began simultaneous trading of its natural gas futures contract on the floor and using the electronic Globex system.⁹⁸ Consequently, futures contracts now trade virtually around the clock, and the market is available electronically to traders all over the world. Electronic trading grew rapidly in late 2006 (see Figure 31), exceeding the volume of pit trading on October 30 for the first time.

Fig 30

Natural Gas Open Interest Growth, 1997-2006

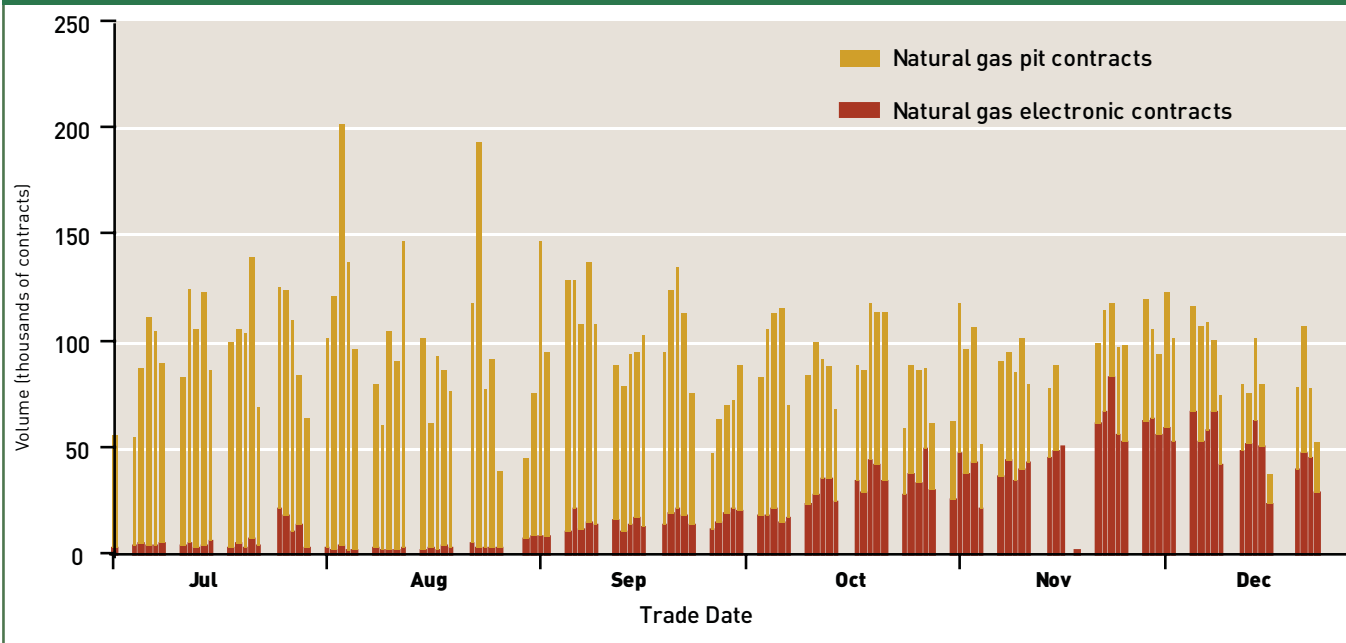


Source: Derived from Nymex data.

98. After-hours trading (trading when the pit is closed) had taken place for many years.

Fig 31

Growth of Electronic Natural Gas Futures Trading Compared to Pit, 2006



Source: Derived from Nymex data.

Activity in Futures and Financial Electric Markets Also Increased

Nymex trading in electric futures has historically been less important than in natural gas. The electric power futures contract now centers on PJM (just as the gas contract centers on the Henry Hub) and has been in place since March 19, 1999. Trading on the electric power futures contract increased 9 percent in 2006.

As noted in the Commission's *2004 State of the Markets Report*, financial trading of electric power on the IntercontinentalExchange (ICE) began to increase rapidly in 2004, especially in PJM.⁹⁹ During 2005 and 2006, the increase in financial electric swap trading continued (see Figure 32). The increases continued for electricity trading in PJM and were particularly notable at western trading hubs, where volume tripled between 2005 and 2006 (though starting from a lower base than PJM's).

Influence of Futures Prices on Some Physical Gas Price Indices

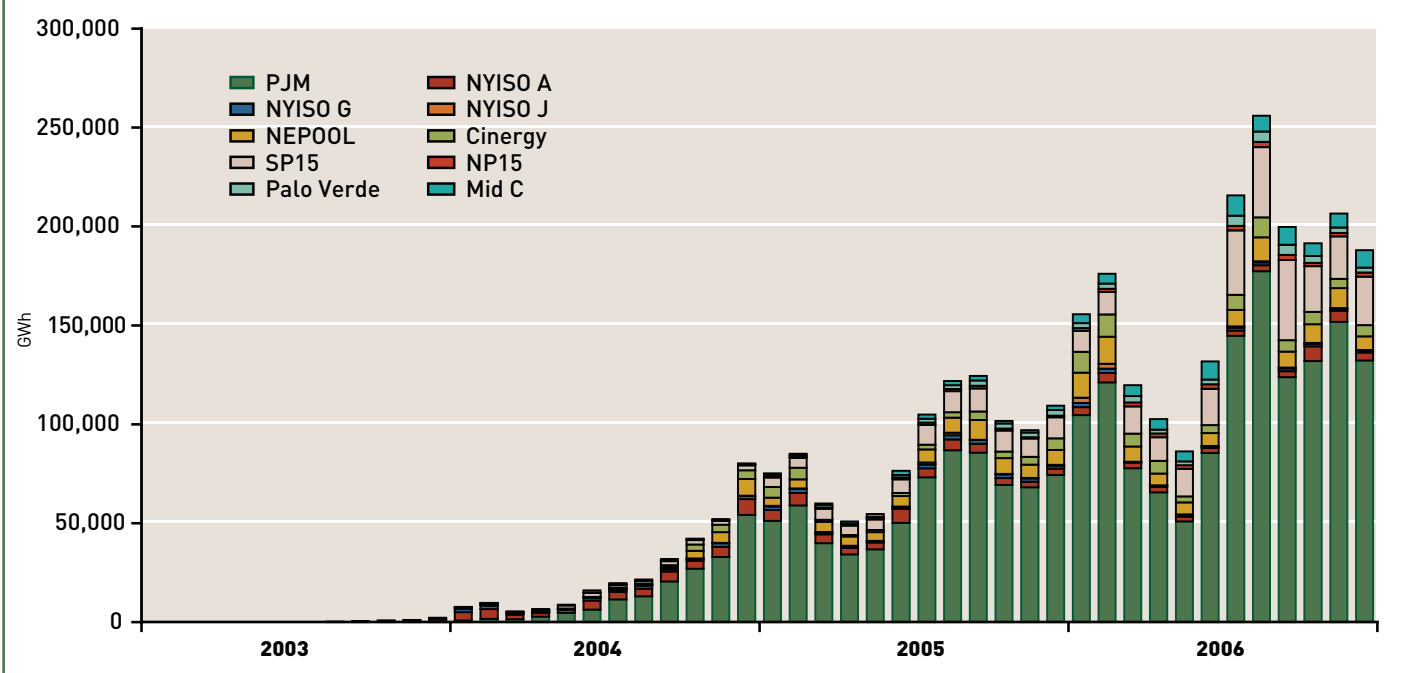
As a practical matter, monthly cash physical and futures natural gas prices are and must be closely related to one another, if markets are working effectively. The fact that many participants can engage in both futures and monthly cash physical markets means that any material differences will be arbitrated away. That is, at least some market participants will pick the least expensive way to establish a position using different combinations of products. In doing so, they will force the values of those different combinations to converge. Consequently, big changes in cash physical market values naturally affect futures trading, and vice versa.

However, in some cases, the mechanisms tying futures to monthly cash physical prices are more direct. Many natural gas market participants in many areas make contracts using

99. 2004 SOM, 63.

Fig 32

Growth of Financial Electricity Trading Volumes, 2003-06



Source: Derived from ICE data.

indices that rely on surveys of fixed-price bilateral physical deals to set prices. For such contracts, the index price rests on an average of monthly cash physical deals made during the last five business days of the prior month (known as bidweek) at fixed prices that are then aggregated by the end of bidweek to form monthly price indices.

By 2006, most of the transactions that set these indices in the Northeast United States and along the Gulf Coast were *physical basis* deals. But many of these physical basis deals set their price as the final settlement price for the Nymex futures contract at Henry Hub plus a fixed, agreed-upon differential. Consequently, in these locations, index prices are effectively an average of these fixed, agreed-upon

differentials added to the final Nymex settlement price. In those areas, index prices reflect the Nymex close.

The prevalence of physical basis transactions varied in indices varied around the country in 2006 (see Figure 33). Physical basis predominated in the Northeast and along the Gulf Coast but not in the rest of the country.¹⁰⁰

The link between index prices used for physical contracts and the Nymex closing price is interesting because conventional wisdom sees the monthly cash physical markets as primary and the futures markets as derivative. The linkage from Nymex futures prices back to monthly cash physical prices and transactions occurs largely because market participants believe the Nymex trading market is reliable; as

100. Monthly indices are only one part of overall market prices in any region. Large gas buyers such as local distribution companies (LDCs) typically buy some gas well in advance of use and put it in storage, and may buy monthly gas using a variety of fixed and floating commodity prices. Furthermore, market-determined physical basis settles after the futures contract, and to some extent can change price in an opposite direction to the Nymex settle. Thus it is difficult to determine the actual financial impact of the Nymex Henry Hub settle on any particular local market natural gas price.

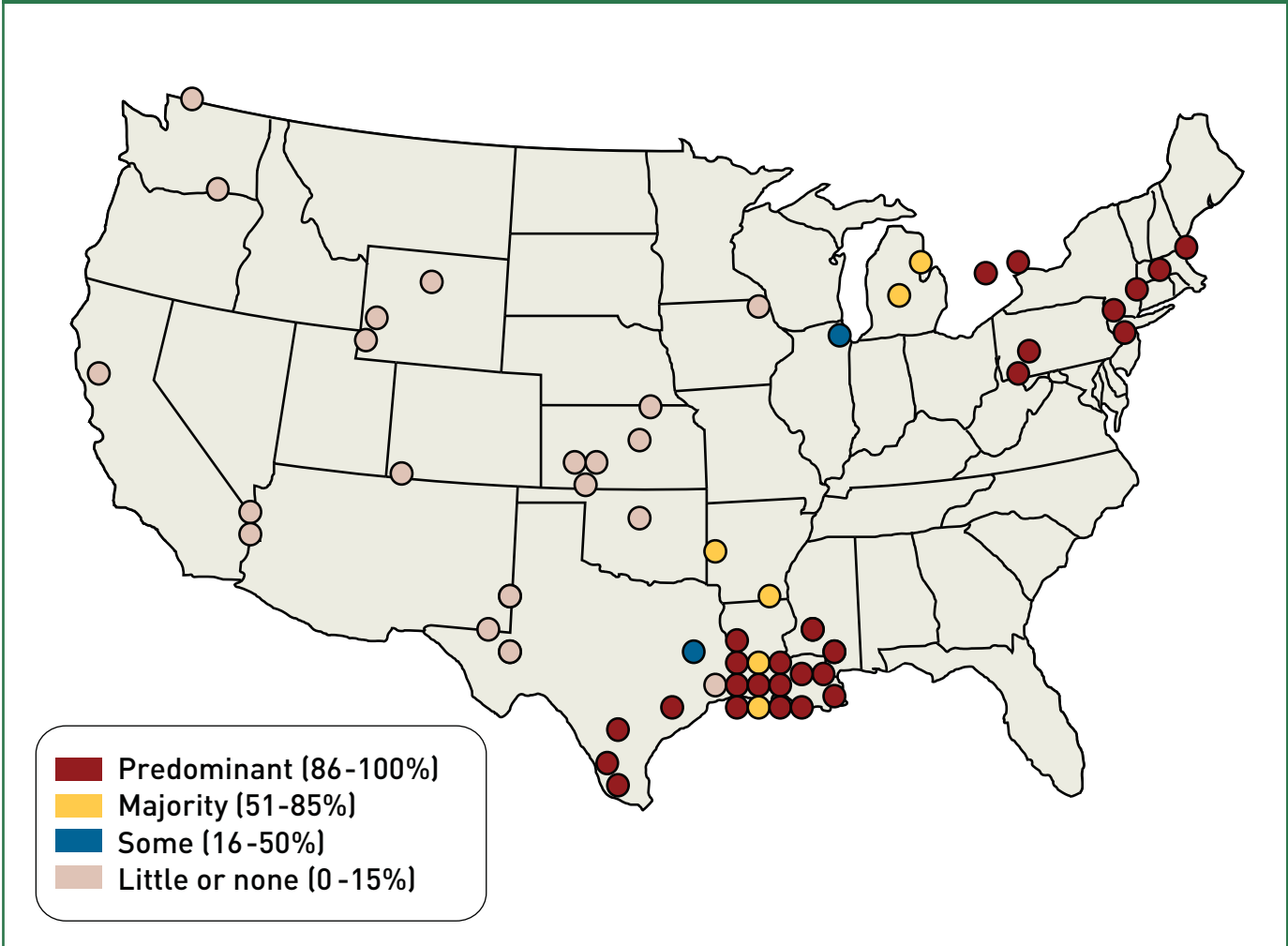
former Commissioner of the Commodities Futures Trading Commission, Sharon Brown-Hruska, said:

Gas buyers often utilize the Nymex monthly settlement prices to determine the prices for swaps and physical transactions. Both sides are willing to reference such a price because they believe that the price is determined in a liquid, efficient and, importantly, transparent market.¹⁰¹

Provided that gas buyers and sellers are correct in their belief about the reliability of Nymex, the use of futures prices to effectively set some physical index prices is an understandable, if perhaps not well understood, practice.

Fig 33

Use of Physical Basis in Natural Gas Price Indices at Major Trading points, 2006



Source: Staff analysis of Platts data.

101. CFTC Commissioner Sharon Brown-Hruska, "The Functions of Derivative Markets and the Role of the Market Regulator," address at 2006 Planalytics GasBuyer Client conference, May 18, 2006, available at: <http://www.cftc.gov/opa/speeches06/opabrownhruska-45.htm>.

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The site is organized as follows:

State of the Markets: An overview that summarizes the key points of the natural gas and electric market content provided on this site.

Reports & Analyses: Reports that consider key issues affecting natural gas and electric markets.

Market Snapshots: Division of Energy Market Oversight presentations at the Commission's Open Meetings.

Market Views: Collections of market information prepared for various audiences.

Electric Power Markets: An understanding of U.S. electricity markets.

Natural Gas Markets: An understanding of U.S. natural gas markets.

Other Markets: An understanding of the other U.S. energy markets.

Glossary: Brief definitions of certain terms used under Market Oversight.

Acronyms: Most commonly used acronyms under Market Oversight

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