Electric Power Market Summary

SUMMER 2006

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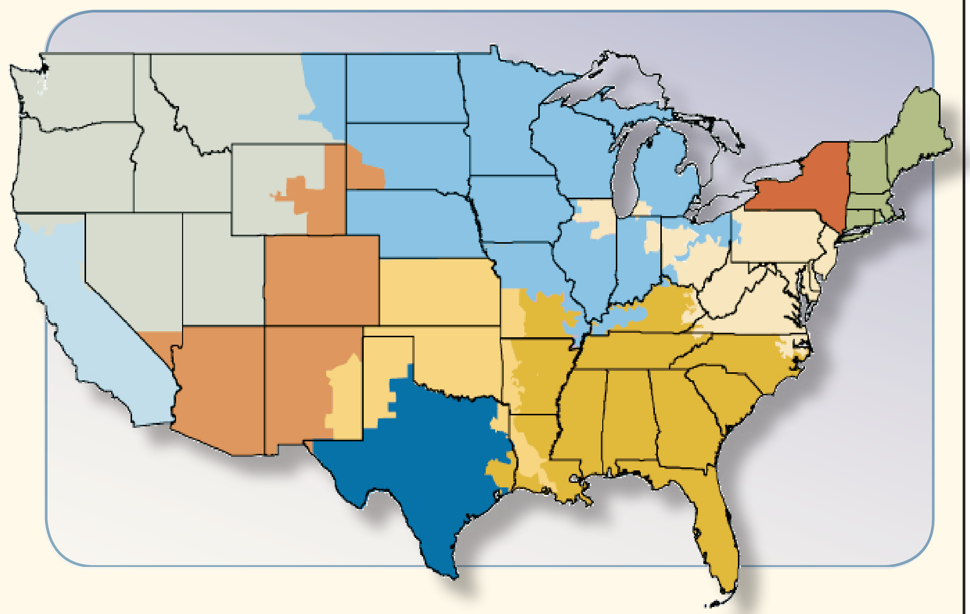
Peak electrical demands in summer 2006 were much higher in almost all regions of the United States than in summer 2005. Every regional transmission operator (RTO), and most other regions, set demand records. The bulk power grid and wholesale power markets performed well under the stress.

Ten percent more electricity was produced by natural gas-fired generators in summer 2006 than in summer 2005. Lower-priced gas, newly installed gas-fired generators, and more expensive fuel oil all contributed to this trend.



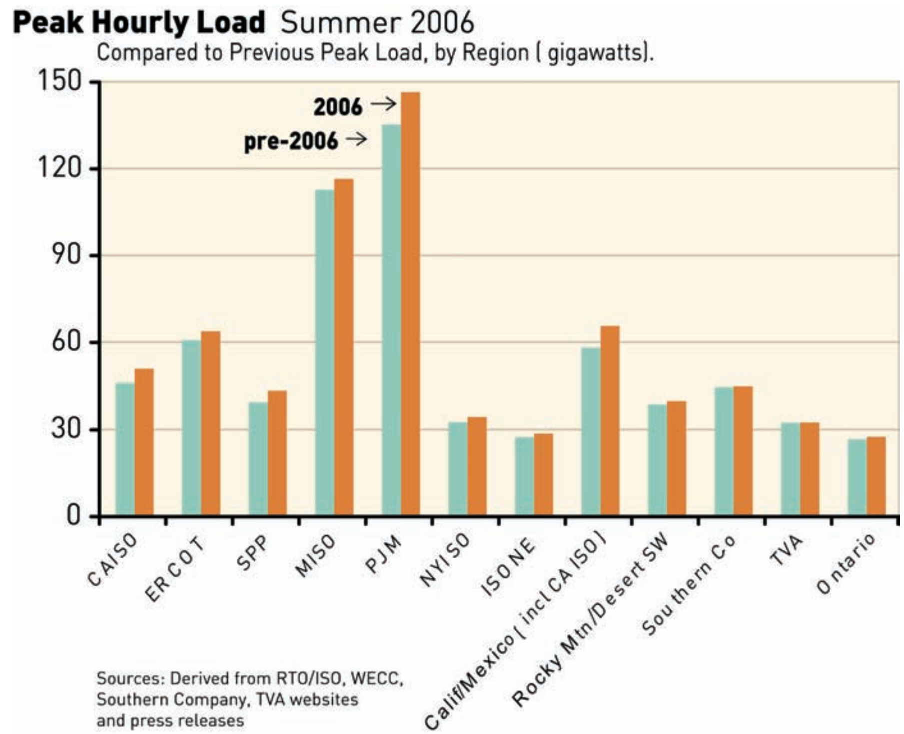
Despite spells of record-breaking heat, U.S. consumption of electricity in summer 2006 grew only one percent from the previous summer. Milder weather in parts of June and August reduced consumption in most major power-consuming regions except in the West.

Unprecedented generation availability and robust demand response[1] helped grid operators maintain reliability during peak periods, but in almost every area they still needed emergency actions such as warnings, public conservation, emergency transactions, and curtailment of interruptible loads. Even areas considered vulnerable—southern California, southwest Connecticut, Long Island, and Ontario— had no load shedding[2] or serious market problems.

Compared to summer 2005, average wholesale prices for electricity declined in the Northeast and Midwest and rose in PJM (Mid Atlantic and portions of the Midwest) and California. Throughout summer 2006 prices were moderated by lower natural gas prices, greater supplies of nuclear and hydropower, and occasional moderate weather. During hot weather, prices rose to reflect the use of more-expensive generators and, during extreme peak loads, scarcity, though the price levels and scarcity mechanisms varied by region.

Peak Demands Much Higher in 2006

Peak electrical demands[3] in summer 2006 were much higher in almost all regions of the United States and many demand records set in summer 2005 were broken. The California Independent System Operator (CAISO), PJM and the Midwest ISO (MISO) saw substantial growth in peak demand. All RTOs, and most other regions, exceeded their historic peak demand. Growth of peak demand is significant because it stresses both the grid and the markets. In summer 2006, both functioned without significant disruptions.



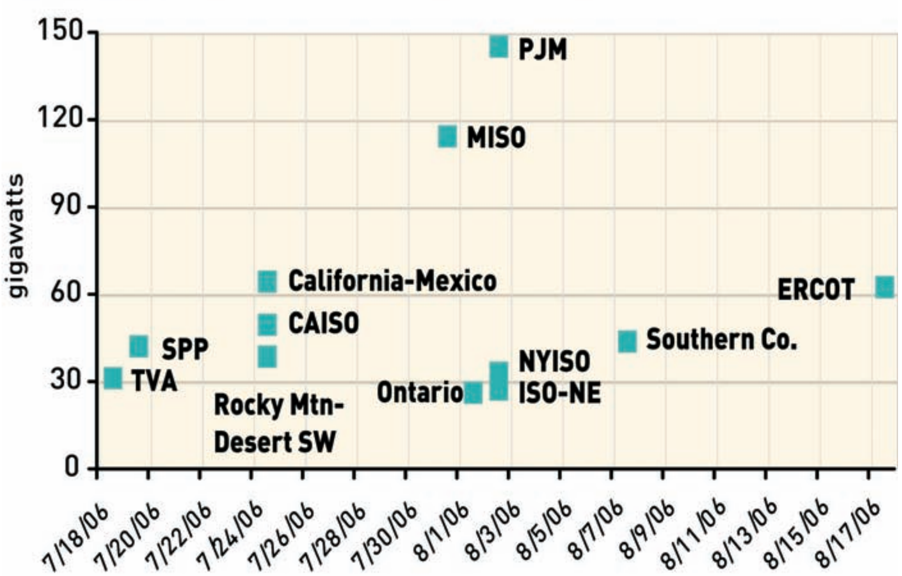
[1] Changes in electric usage by end-use customers in response to price changes or incentive payments. For a complete definition see Assessment of Demand Response and Advanced Metering (FERC Staff Report, August 2006.)

[2] "Load shedding" means disconnecting consumers from the grid, usually to prevent demand from exceeding supply, causing widespread grid collapse; "rolling blackout" is synonomous. "Blackouts" are failures of the grid to provide power for any reason. In this report the terms mean failure of the bulk power system, not the failure of local distribution systems or the disconnection of consumers, such as interruptible customers, whose contracts or terms of service allow for such disconnection.

[3] Peak demand is a region's highest hourly power demand during the summer. Average demand is the average of all hourly demands in a region during the summer. The terms "demand" and "load" are used interchangeably in this document to mean system power averaged over an hour.

Monthly peak demand records also were widely broken, especially in May 2006. Pre-summer hot weather can be troublesome if generation supplies have not yet fully returned from spring maintenance: ERCOT had a two-hour rolling blackout in April 2006 and the New York Independent System Operator (NYISO) had an April heat problem in a prior year.

Date and Size of Peak Load Summer 2006



Sources: Derived from RTO/ISO, WECC, Southern Company, TVA websites and press releases

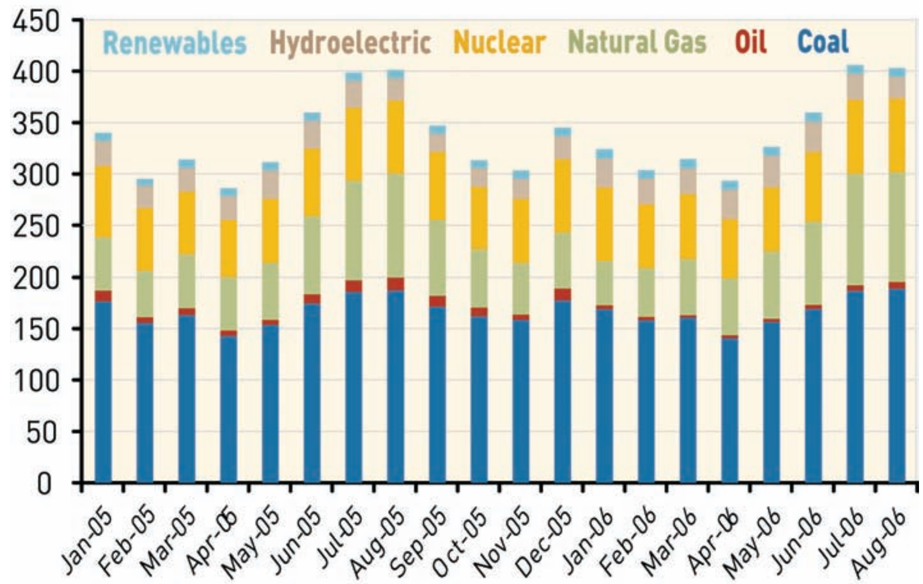
But in May 2006 the heat occurred at the end of the month, when most generation was available. Nevertheless, NYISO experienced large real-time price excursions when unusual congestion combined with thunderstorm reliability procedures to slow its real-time software, leading to drastic schedule changes with neighboring PJM and Ontario.

Large Increase in Natural Gas-Fired Generation

Gas-fired power generation rose 10 percent in summer 2006 over summer 2005 (see charts Net Generation by Energy Source and Change in Net Generation Output by Source.) The Western Electricity Coordinating Council (WECC) and Florida Reliability Coordinating Council (FRCC) regions, both strongly gas-dependent, had the largest increases in gas consumption for power generation, according to estimates by consultant Bentek Energy LLC. Several factors contributed to the increase. Natural gas was 10 to 20 percent cheaper, depending on location, in summer 2006 compared to summer 2005. High peak demands required greater use of the least-efficient generators, including gas-fired combustion turbines.

Net Generation by Energy Source

Thousands of gigawatthours per month



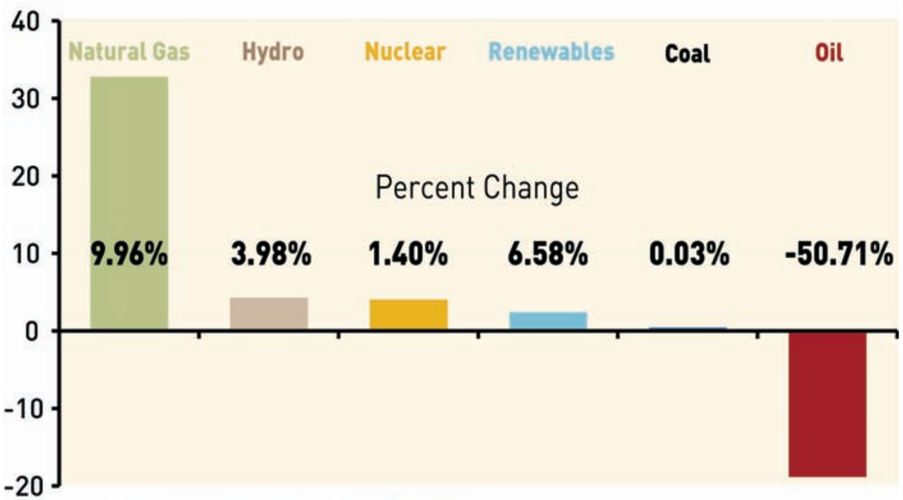
Source: Derived from Energy Information Administration (EIA), Electric Power Monthly data

Nationwide, about 20.2 gigawatts (GW) of new gas-fired generating capacity was added since summer 2005, out of a total addition of 22.6 GW.

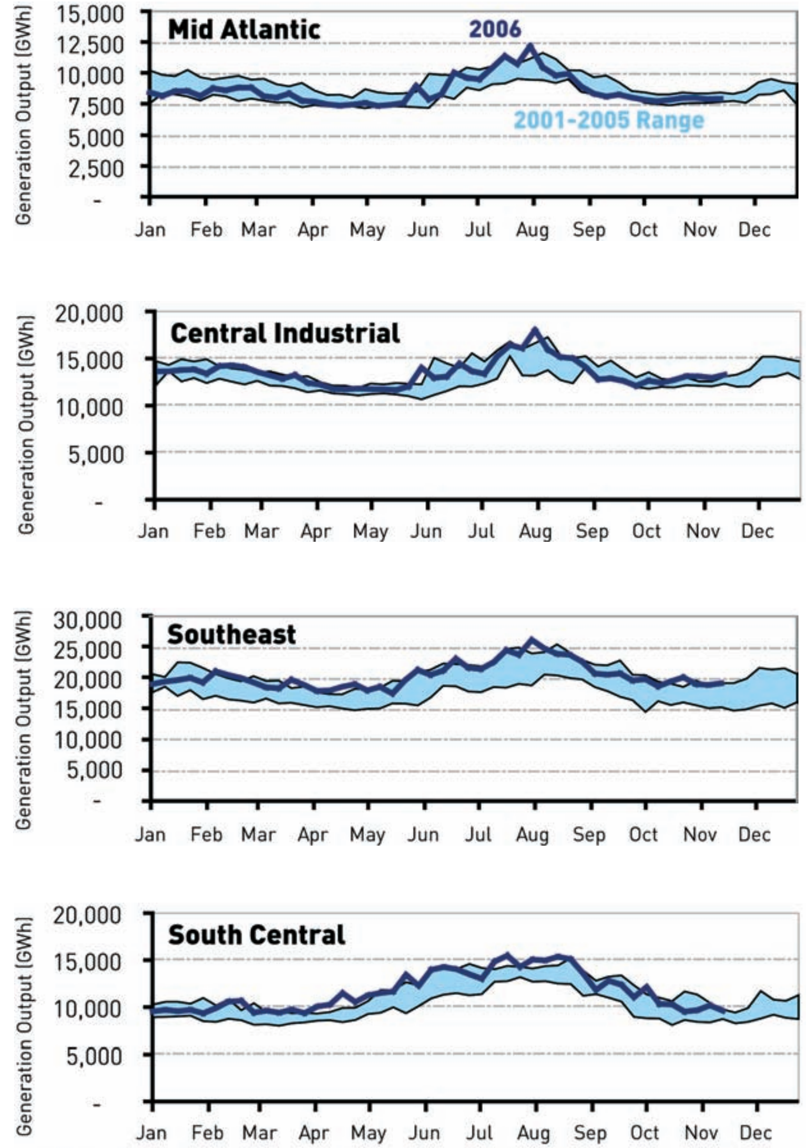
Output also increased from hydropower, nuclear and renewable generators, while coal-fired output was almost unchanged. Power generation from oil fell sharply. Fuel oil prices were higher than natural gas prices in summer 2006, while in summer 2005 oil had been cheaper than gas.

Change in Net Generation Output by Source

May - August 2006 compared to same period 2005 Thousands of gigawatthours



Source: Derived from EIA, Electric *Power Monthly* data



Source: Derived from Edison Electric institute (EEI), *Weekly Electric Output* data.

Electrical Consumption Grew Modestly

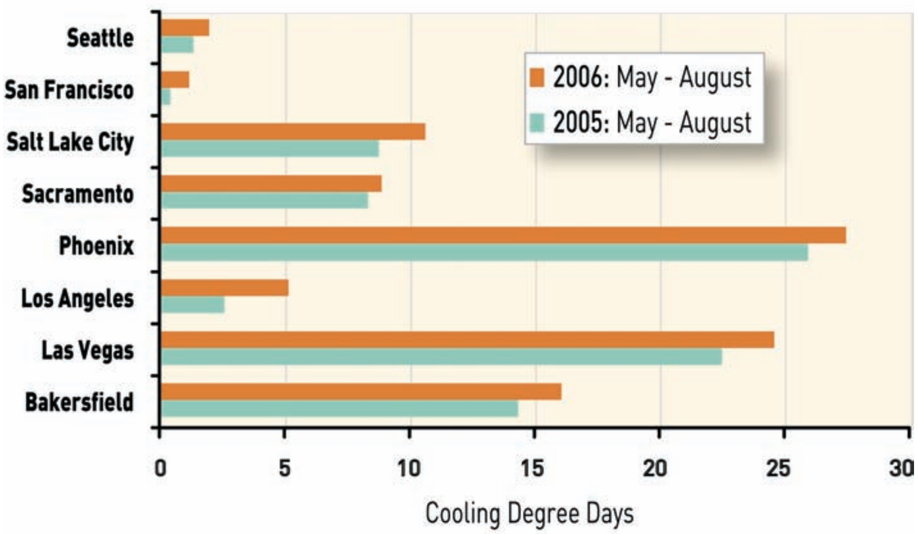
In summer 2006, despite record-breaking heat waves and the second-warmest[4] summer on record, U.S. consumption of electricity grew only one

[4] National Climatic Data Center, Report on Climate of 2006- August in Historical Perspective including Boreal Summer, September 14, 2006.

percent from the previous summer. Milder weather in June and August reduced consumption in most of the major power-consuming regions outside the West.

Western cities needed more cooling in 2006 than in 2005, but many eastern cities needed less. This diversity in cooling requirements also limited U.S. electricity consumption growth. The following figures show average cooling requirements measured in cooling degree days[5] for both summers.

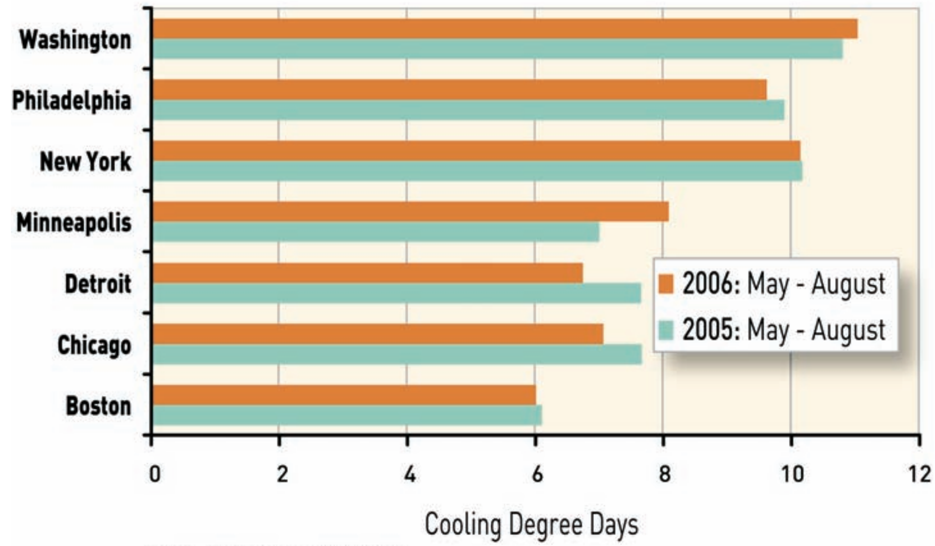
Average Daily Summer Cooling Requirements
Western Interconnection



Source: Staff analysis of National Oceanic and Atmospheric Administration (NOAA) data

[5] A cooling degree day is a measure of demand for air conditioning. The positive difference between the daily mean temperature and 65°F is the number of cooling degree days for that date.

Average Daily Summer Cooling Requirements
Eastern Interconnection



Source: Staff analysis of NOAA data

Bulk Power System Performed Well Under Stress

The U.S. bulk power system performed well in the face of very high demand. There were no instances of involuntary load-shedding (blackouts.) In the West, the 11-day heat wave broke demand records not only during peak hours but during weekend days as well, raising concerns that operators would be unable to schedule needed maintenance for generators. But suppliers and system operators seemed well-prepared: generators on average were available a larger fraction of the time in California, for example, than in any previous summer, and the transmission system, critical in import-dependent California, also performed well.

Consumers contributed by responding strongly to public appeals for conservation, and hydropower supplies were more abundant than normal. Even so, CAISO reached a Stage 2 emergency (when operating reserves are below or are expected to fall below 5 percent), allowing it to call upon interruptible customers to curtail use. The combined effect of interruptible and curtailable loads, conservation, and other utility load-reduction programs was a 4.1 percent reduction, more than 2,000 MW, at the peak day and hour. Neither southern California (identified by FERC in May 2006 as an area of summer concern[6]) nor any other region in the West was subjected to involuntary load-shedding.

Eastern areas also weathered the heat well. Southwest Connecticut, also flagged for concern,[7] benefited from ISO-New England's demand-response programs—which were particularly effective in Southwest Connecticut—and record-high availability of generators. Long Island was considered vulnerable[8] due to a tight demand and supply balance and limited import capabilities; as elsewhere, good demand response and high availability of generation helped avoid problems. Long Island Power Authority (LIPA) also credits strict planning criteria and good transmission performance.[9]

During summer 2005 Ontario experienced many transactional problems with imports and exports, raising concerns[10] that it could adversely affect neighboring MISO and NYISO in 2006, but a new day-ahead scheduling process reduced such problems by 90 percent. Ontario's Independent Electricity System Operator (IESO) said good generation availability (including from wind and hydropower), new capacity, and Toronto-area transmission upgrades also helped avoid operational and market problems during hot weather.

In general, generator outages were at unusually low levels during the summer. This improved availability was important to maintaining reliability during hot weather. Nuclear power plants operated at 96 percent of their total capability during June, July, and August, compared to 94.6 percent during the same period in 2005, amounting to an additional 1,350 MW on average. NYISO said only two generators were forced out of service during the heat waves, which suggests much better than average availability.[11] California reported that during its peak week it had the lowest power plant outage rate ever. PJM and New England also reported good availability. The Midwest Independent System Operator (MISO) region was an exception. High temperatures in cooling water sources and limits on discharge temperatures kept some generators there below full output.

Robust demand response was a common factor that significantly improved reliability in several regions. Demand response took several forms: voluntary conservation, paid capacity-based programs, and utility-

[6] See Summer Energy Market Assessment (Item A-3), Commission meeting of May 18, 2006; http://www.ferc.fed.us/EventCalendar/Files/20060518103507-A-3-with-talking-ptsl.pdf.

[7] Ibid., note 3.

[8] Ibid., note 3.

[9] Distribution-level systems did not fare as well as transmission during heat events. LIPA experienced a few distribution line overloads. In nearby Queens, Consolidated Edison had extensive local outages when a number of distribution lines were damaged by overloading. Southern California Edison replaced hundreds of distribution transformers.

[10] Ibid., note 3.

[11] NYISO planned for a forced outage rate of 5.43 percent, equal to about 2,100 MW on average.

administered load control and interruptible load. Notably, demand response in NYISO's western zones on Aug. 2 assisted PJM on its peak day by improving NYISO transmission voltages enough to allow all scheduled exports to flow to PJM.

Market Prices Reflected Supply and Demand

Electricity markets generally performed as expected in response to combinations of higher peak demands, moderate average demand, lower natural gas prices and better generating availability. The following table shows that prices rose in RTOs with the greatest increase in peak summer demand. For example, PJM's record peak demand increased 8 percent and its average summer 2006 price was 14 percent higher than summer 2005. California's peak rose 10 percent and its average price rose 5 percent.

Summer 2006 Average Day-Ahead On-Peak Prices and Changes from 2005

Region	2005	2006	Change	% Change
Mid-Atlantic (PJM Western Hub)	$64.51	$73.23	$8.72	14
California (NP15)	$65.15	$68.71	$3.56	5
Midwest (Cinergy Hub)	$52.86	$47.90	-$4.96	-9
New York (Zone J)	$110.37	$101.19	-$9.38	-9
New England (ISO -NE Internal Hub)	$75.36	$63.63	-$11.73	-16

Source: Derived from Platts Megawatt Daily and RTO/ISO data.

Where record peaks grew more modestly, prices fell. MISO, ISO-NE, and NYISO peaks grew less than 6 percent, and the New York City load pocket (Zone J) had approximately one gigawatt of new, efficient gas-fired generation in summer 2006. Prices fell in all three regions.

Scarcity Pricing Present in Several Areas During High Loads

Prices rose to very high levels during heat waves in both RTO-administered spot markets and in bilateral markets.

In NYISO, scarcity pricing is activated when demand-response measures are needed to maintain operating reserves or meet emergency conditions. NYISO's two demand-response programs were used locally or systemwide on July 18, July 19, Aug. 1, Aug. 2, and Aug. 3. Under these conditions, the clearing price is the higher of the locational price or the scarcity (demand-response) resource offer. Scarcity prices set price floors on these days. Hourly settlement prices for some zones ranged from $420/MWh to $1,500/MWh for one to five hours on each of these days.[12]

ISO-NE activated scarcity pricing on Aug. 1 and Aug. 2 as 30-minute reserves were depleted during peak hours. On Aug. 1, scarcity prices were activated for less than two hours in all zones but Maine, and on Aug. 2 scarcity pricing was active about four hours in all zones. During these periods the ISO administratively set the systemwide energy price to $1000/MWh.

In MISO the conditions for activating scarcity pricing did not occur. During peak loads on July 31 through Aug. 2, MISO took Energy Emergency Alert (EEA) actions that trigged the loss of interruptible load and implemented utility level demand-response programs. The resulting lower loads helped maintain adequate reserve levels and lowered prices. In review, the MISO Independent Market Monitor raised questions about

[12] High locational prices also resulted from co-optimization of energy and reserves, a market design element that reflects reserve values in energy prices.

the interaction of EEA actions and pricing.[13] If scarcity pricing (called shortage-condition pricing in MISO) is invoked, operating reserves used for energy are offered at $1,000/MWh and are eligible to set the price.

Scarcity pricing was not triggered in PJM in summer 2006. To trigger it, the RTO must dispatch emergency generation, reduce voltage or take other emergency actions. PJM issued warnings of such actions (such as a voltage reduction) but never implemented them. PJM's scarcity pricing provisions call for the locational marginal price for the entire region to be set by the highest offer price.

In bilateral markets, scarcity was reflected in both bilateral trading and in the relationship between power and fuel prices. For example, bilateral prices reached, and in some cases exceeded, the western soft cap[14] of $400/MWh, as shown in the following table.

On-Peak Day-Ahead Western Bilateral Prices Summer 2006

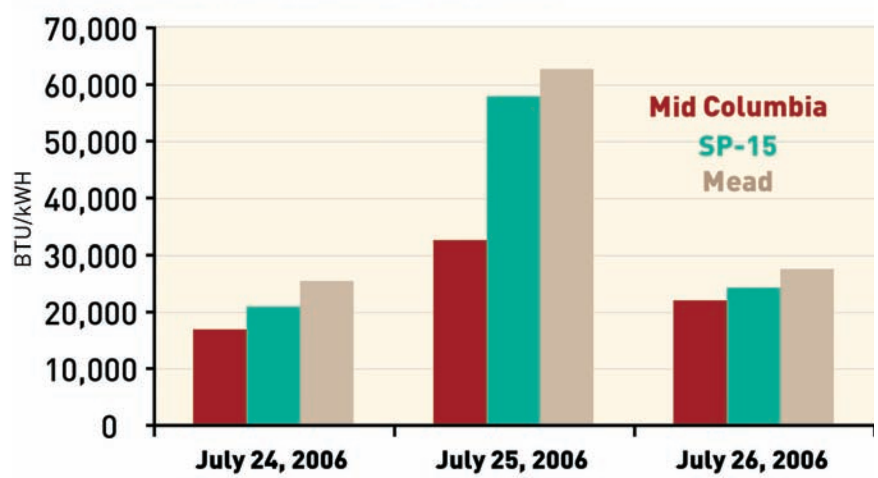
	July 24			July 25			July 26		
	High	Low	Avg	High	Low	Avg	High	Low	Avg
COB	$106	$97	$100	$315	$200	$258	$167	$136	$149
Four Corners	$200	$108	$124	$375	$250	$332	$197	$156	$178
Mead	$226	$109	$138	$413	$225	$365	$200	$151	$177
Mid Columbia	$120	$87	$90	$285	$150	$192	$155	$129	$144
NP-15	$220	$101	$120	$399	$250	$345	$190	$145	$169
Palo Verde	$200	$101	$115	$399	$200	$297	$185	$138	$161
SP-15	$220	$101	$123	$400	$250	$367	$190	$143	$167

Source: Derived from Intercontinental Exchange (ICE) day-ahead price data.

An indicator of scarcity is the ratio between the price for natural gas and the price for electricity. Known as an implied heat rate, it is the efficiency with which a generator must convert gas to electricity to break even, given their prices. If market prices for electricity and gas are such that even the least-efficient generator could make money—that is, the implied heat rate is very high—it indicates that there may be a scarcity premium in the price of electricity.

The actual heat rate for a simple cycle gas-fired generator is typically about 10,000 Btu/kWh, and the least-efficient plants need 20,000 Btu/kWh. The chart shows that implied heat rates in the west between July 24 and July 26, 2006 were well above those levels, strongly suggesting a scarcity premium in electricity prices.

Implied Heat Rates, Western Price Points



Source: Staff analysis of ICE electricity and natural gas prices

[13] The Independent Market Monitor noted a lack of explicit rules coordinating shortage pricing and emergency operating procedures and recommended MISO develop ways to prevent suppressing "legitimately high prices" with emergency procedures during shortage conditions. Patton, David; Independent Market Monitor Review: 2006 Peak Load Event; September 20, 2006 http://www.midwestmarket.org/publish/Document/3c9065_10e9e96031d_-7e6b0a48324a

[14] By order dated Feb. 16, 2006, the Commission modified the price cap on spot market sales in the WECC outside of the CAISO to a $400/MWh "soft" cap, 114 FERC 61,135, paragraph 1. A soft cap allows market participants to submit bids above the bid cap with adequate justification, in this case for sales that are 24 hours or less and are entered into the day of or day prior to delivery in WECC or in CAISO.