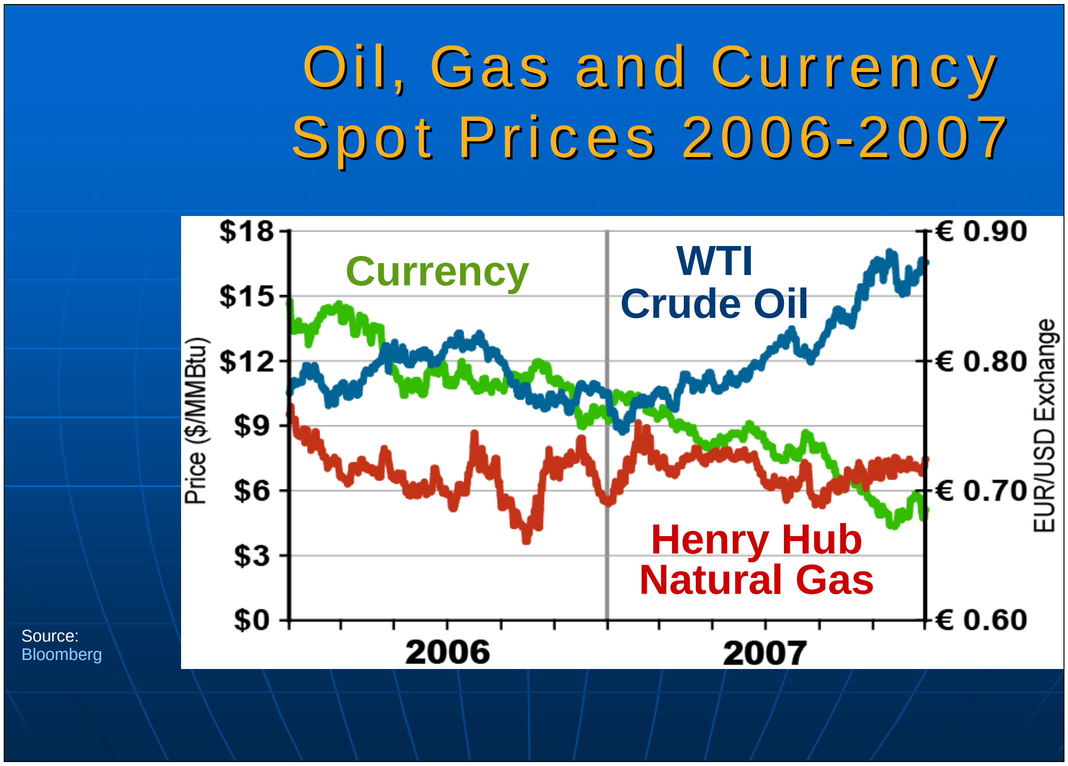
2007
State of the Markets Report

Item No.: A-3

March 20, 2008

Mr. Chairman and Commissioners, good morning. I am here to present the State of the Markets Report for 2007. With me from the Office of Enforcement are Chris Peterson, who directs the Gas group in the Division of Energy Market Oversight and Keith Collins, who directs our Electric group. Also with me is Jeff Wright, Deputy Director of the Office of Energy Projects. This presentation will be posted on the Commission's Web site today, and we will provide more comprehensive results of our analysis on the Web site over the next few weeks.

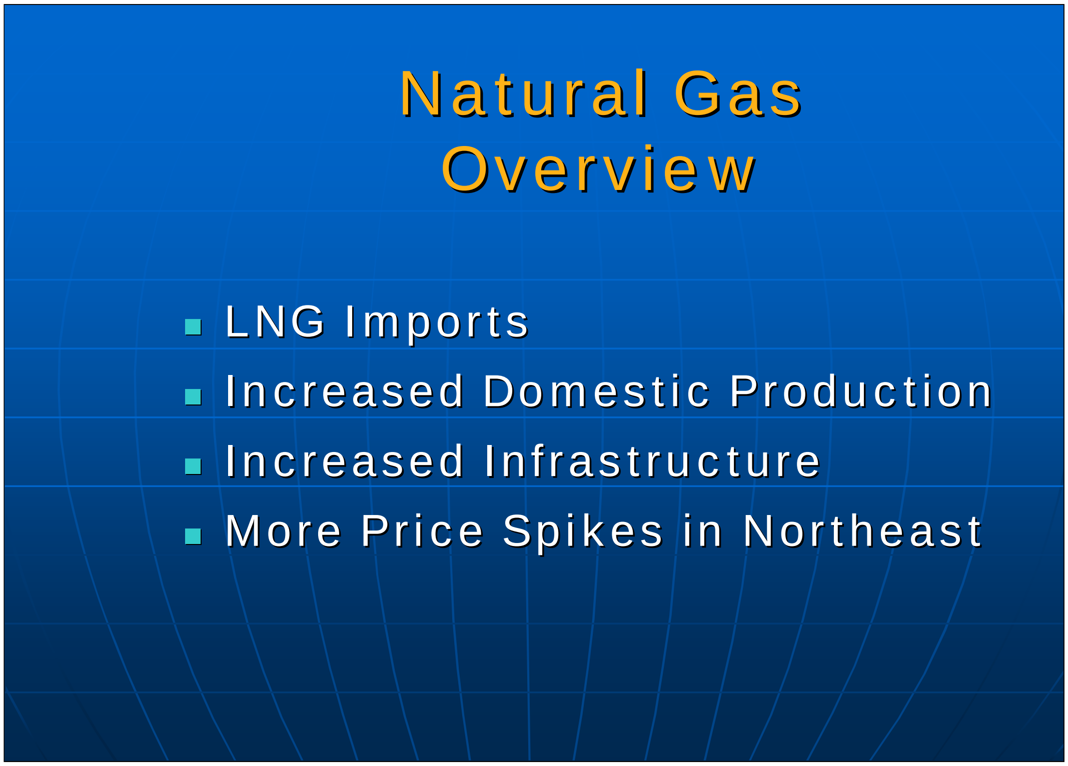


To understand how United States energy markets behaved in 2007, we need to start with two facts. Since the beginning of 2006, crude oil prices in U.S. dollars have increased by 74%. At the same time, the value of the dollar has fallen by 28% against the euro since the beginning of 2006. These two changes have substantially affected the competitive positions of our domestic energy industries – affecting imports and exports of both gas and coal and changing usage patterns for natural gas.

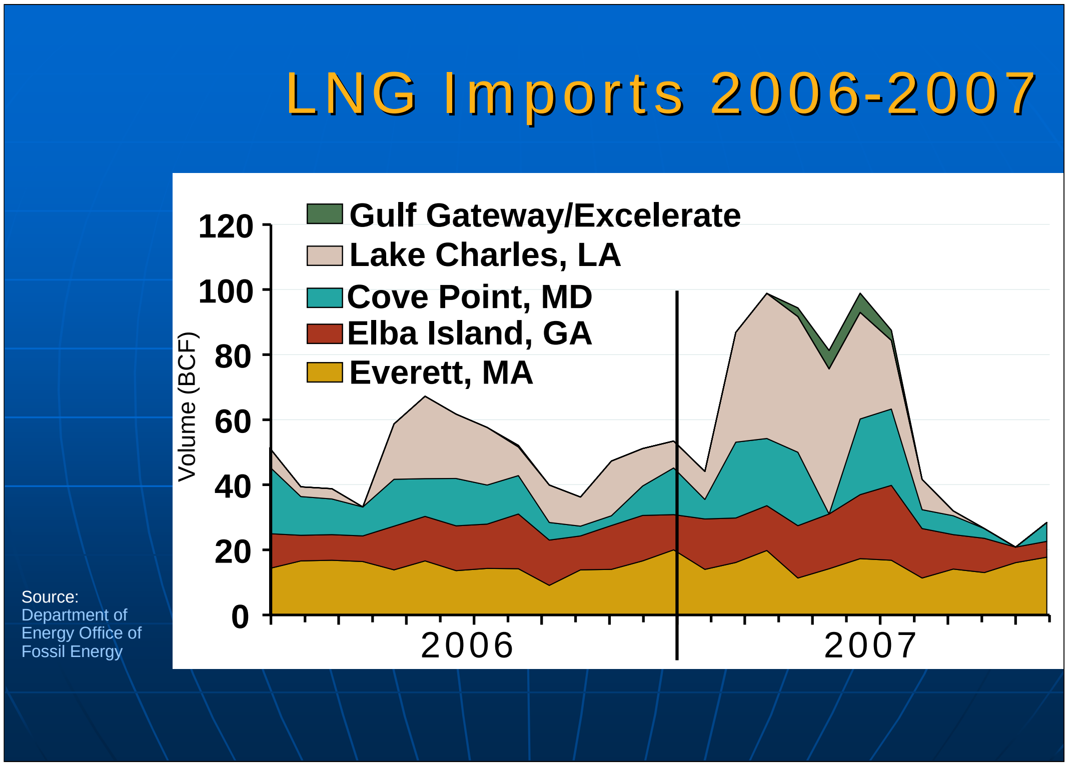
During 2006 and 2007, the most striking aspect of natural gas prices was their contrast to oil and currency prices: U.S. spot gas prices stayed mostly in a fairly narrow band between $6 and $8 per MMBtu. Prices in 2007 at the Henry Hub averaged about 3% higher than in 2006. That meant that natural gas was far cheaper than oil for the same heat content almost everywhere and almost all the time in 2007. As a result, generators who could switch from oil to gas almost certainly did so most of the time. That helps account for the fact that natural gas use in electric generation went up by 9% during the year, although oil use also increased.

Let me mention that so far in 2008, the pattern has been quite different. The dollar has continued to fall and oil prices have been as high as $111 per barrel. But natural gas prices in the United States have also risen substantially. Last week, the average future prices for the six months starting in April reached a high of $10.39 per MMBtu.

Even last year, however, gas prices were much higher than they were a few years ago. That led to a production response. United States natural gas production was up more than 3% in 2007. New pipeline projects entered service in 2007, flowing this new gas production to markets.



In reviewing natural gas markets in 2007, I will focus on imports of liquefied natural gas (LNG), increased domestic production, increased infrastructure, and pricing issues in the Northeast.

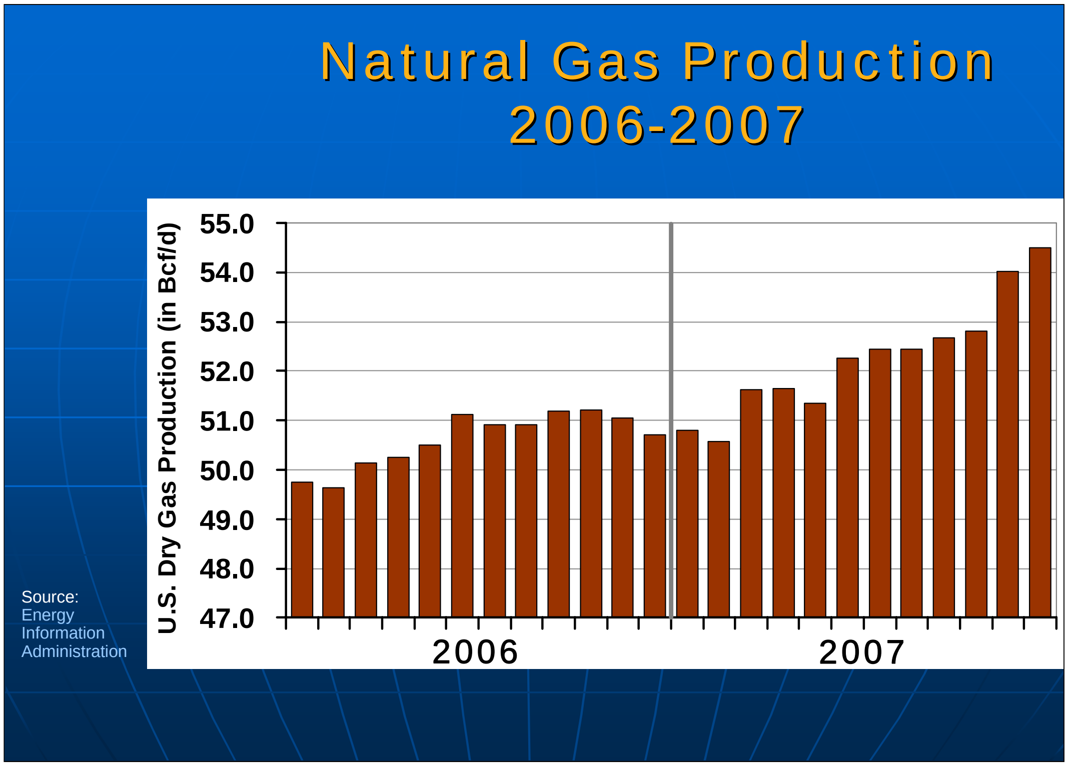


To start with LNG, the slide shows that for the first two-thirds of 2007, the United States received record amounts of LNG, partly because European prices were much lower than American prices. Indeed, we set an annual record for imports for the whole year.

But during the last few months of the year, competing markets offered higher prices, so that by December the United States had the lowest LNG imports for any month since 2002. Asian buyers, in particular, bought a record amount of Atlantic Basin LNG – 60 Bcf a month since September, partly to offset nuclear plant outages in Japan. Within the Atlantic Basin itself, higher European prices gave shippers little reason to send gas to most North American terminals.

In the future, shipments to the United States will depend on relative demand and prices around the world. In some years, imports may be higher than in others. But the basic need for LNG in the United States remains strong. It serves an essential peaking function for the Northeast in the winter and Florida in the summer. It takes advantage of abundant United States gas storage to buy LNG in the summer and deliver it in the winter. And, as production costs rise in the United States, LNG is likely to serve an increasing baseload function for the country as a whole, as it already does for New England.

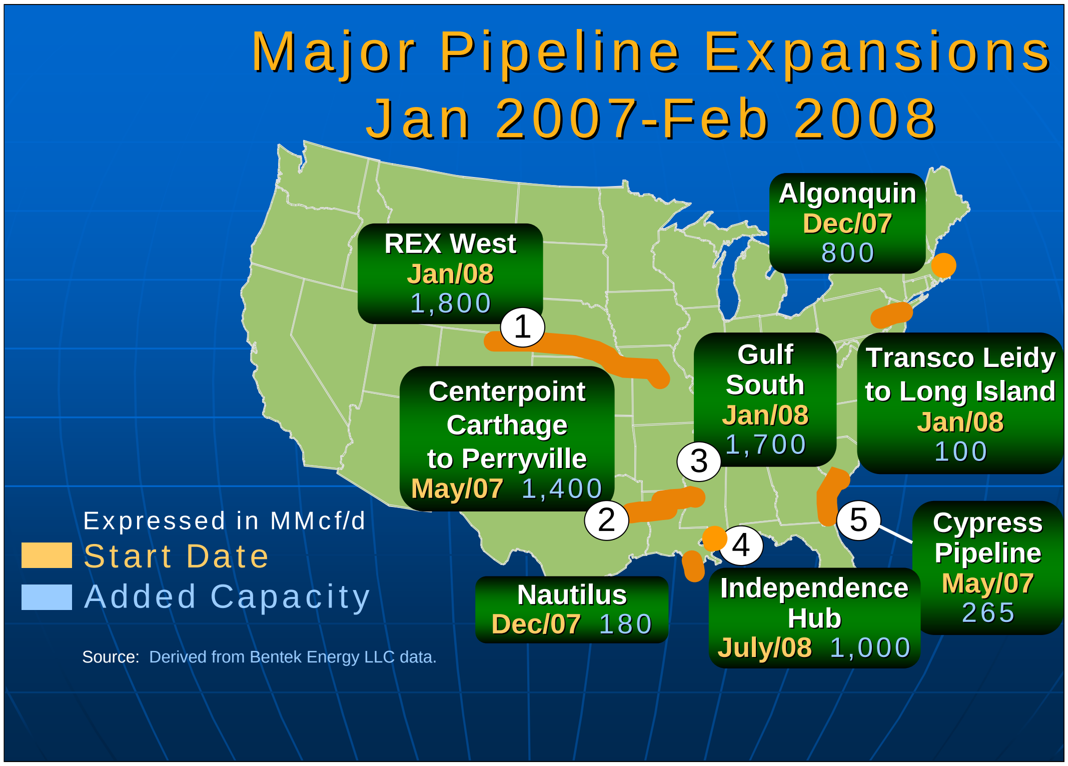
Finally, natural gas was not the only fuel affected by global conditions. Central Appalachian coal saw greater demand from global markets, especially late in the year. As a result, exports of Appalachian coal rose by 35% in November and December, compared to a year earlier, and prices rose by 18%.



LNG imports were down in the second half of 2007; natural gas usage in electric generators was up; and prices stayed relatively stable until the beginning of 2008. How was this possible? The answer is two-fold: domestic natural gas production is up, and new pipelines are bringing new supplies to market. On production, the latest Energy Information Administration (EIA) reports say that natural gas production increased by 3.3% in 2007.

That is largely the result of tapping new gas sources in East Texas, the Rockies and federal offshore. Natural gas prices in the United States have now been high enough for long enough to see a significant production response. Much of the new gas comes from relatively new technologies that are economic at recent prices: gas from shale in East Texas and Arkansas, record deep water gas in the Gulf, along with coalbed methane and tight formation gas in the Rockies. In fact, estimates suggest that gas rigs drilling for “unconventional” plays accounted for about 68% of the total gas rig count in 2007.

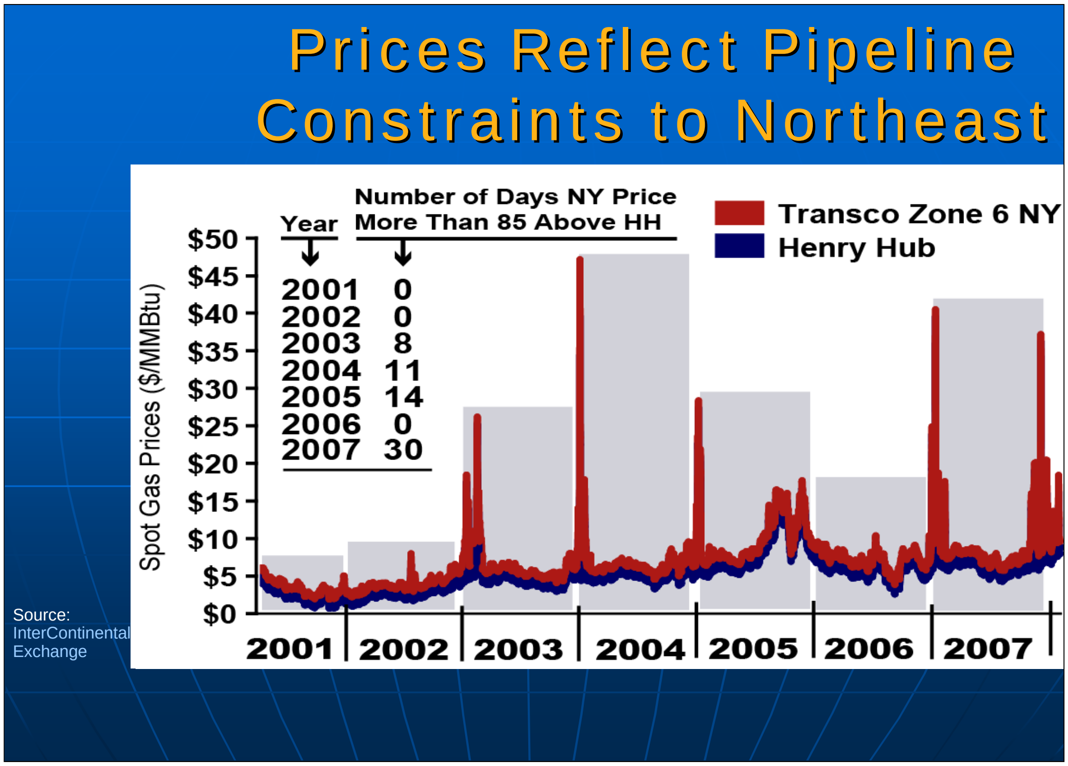
Another key factor helping to keep United States gas prices relatively stable is the abundance of storage. In both 2006 and 2007, we entered the injection season with ample storage inventories following relatively mild winters. This helped alleviate upward price pressure.



Equally important has been the nation's ability to build out its natural gas infrastructure. For decades now, the interstate pipeline system has expanded quickly to meet changing patterns of supply and demand. This ability is especially apparent in the projects placed into full or partial service during 2007 and the first two months of 2008. The most important projects on the slide include:

- New phases of the Rockies Express Pipeline linking Wyoming and Colorado gas production to markets in the upper Midwest – number 1 on the slide. REX West began service in January 2008 and equalized prices between Wyoming and the Midwest. Previously, Wyoming prices often fell to low levels, even reaching one cent per MMBtu with service disruptions at the Cheyenne Hub.
- CenterPoint and Gulf South both connect East Texas with Louisiana across the traditional barrier represented by the Sabine River - numbers 2 and 3 on the slide. Combined, these projects now move more than 2 Bcf/d of incremental gas from East Texas to eastern markets and have reduced the price differences between East Texas and Louisiana.
- Independence Hub connects up to 1.0 Bcf/d of new production in the Gulf of Mexico with onshore pipelines for delivery to downstream markets – number 4 on the slide.
- Cypress's initial phase connects LNG supplies at Elba Island, Georgia, to northern Florida, providing new supply for the growing Florida market, especially in the summer – number 5 on the slide. It also adds diversity to Florida's supply, a key consideration after the hurricanes in 2005. Future phases are under construction and will increase capacity to serve northern Florida.

Taken together these and other pipeline projects placed into full or partial service from the beginning of 2007 through the first two months of 2008 represent more than $6 billion of investment and 14.3 Bcf per day of new deliverability.



The development of Rockies Express largely eliminated a major, persistent price difference between producers in the Rockies and customers in the West and Midwest. The largest remaining price disparities in the country generally occur in the Northeast. During severe winter weather, New York and New England have long seen occasional periods when local prices rose far above those of other regions, including the Henry Hub. These periods appear to have become more frequent. In 2007 alone, gas prices in the Northeast were at least $5 higher than at the Henry Hub on 30 separate days. By contrast, in the six *years* before 2007, northeastern prices were that much higher than the Hub on a total of only 33 days.

Uniquely in the country, gas prices during these periods in 2007 have risen above those of residual fuel oil and, occasionally, distillate fuel oil. Production outages in the Canadian Maritimes have added uncertainty to the northeastern market as well. It appears that the market is signaling that the next major need for expanded infrastructure would be to deliver natural gas to the Northeast.

Let me turn to electric power. I'll start by looking at how wholesale markets differ in different parts of the country. Then I'll focus on basic volume and price trends, new generation builds and the industry's ability to respond to stress.

Three Electric Markets

Spot Electric Power Trading on ICE by Region, 2007, '000 GW Hours			
Region	Physical Trading	Financial Trading	Load in 2006
Northeast	0.5	91.1	1,026.4
Midwest	1.4	40.6	520.0
West	66.9	<0.1	709.8
Southeast	1.4	0.0	802.3
ERCOT	21.3	1.8	305.7

Source: ICE and Form 714. (Note that ICE has no contracts within SPP.)

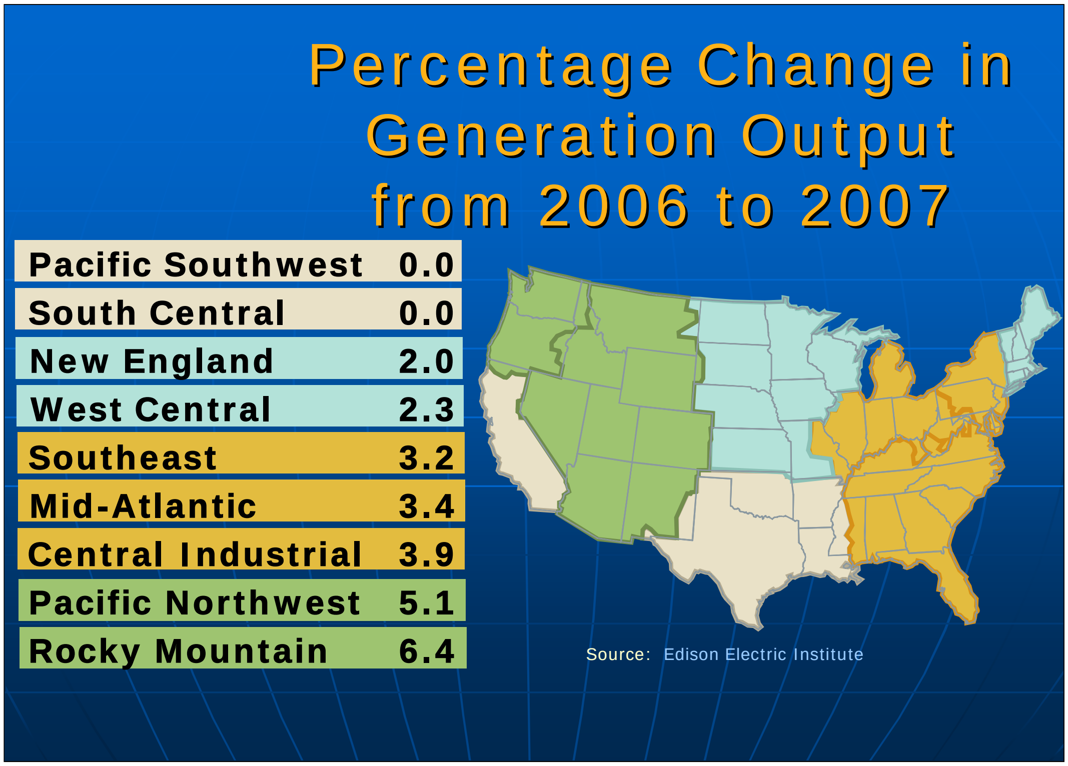
The most striking feature of American electric power markets is that there are really three quite different wholesale market regimes in different parts of the country. In regions where RTOs have day-ahead markets, bilateral spot markets act primarily as intraday derivatives of the prices RTOs produce. In the West, bilateral spot markets form the basic day-ahead physical market. And in the Southeast, bilateral spot markets appear to be a residual market for small amounts of power traded after the integrated utilities have handled most of their own loads.

The IntercontinentalExchange – ICE – provides the clearest view we have into bilateral spot markets, by which I mean day-ahead and intra-day trading.

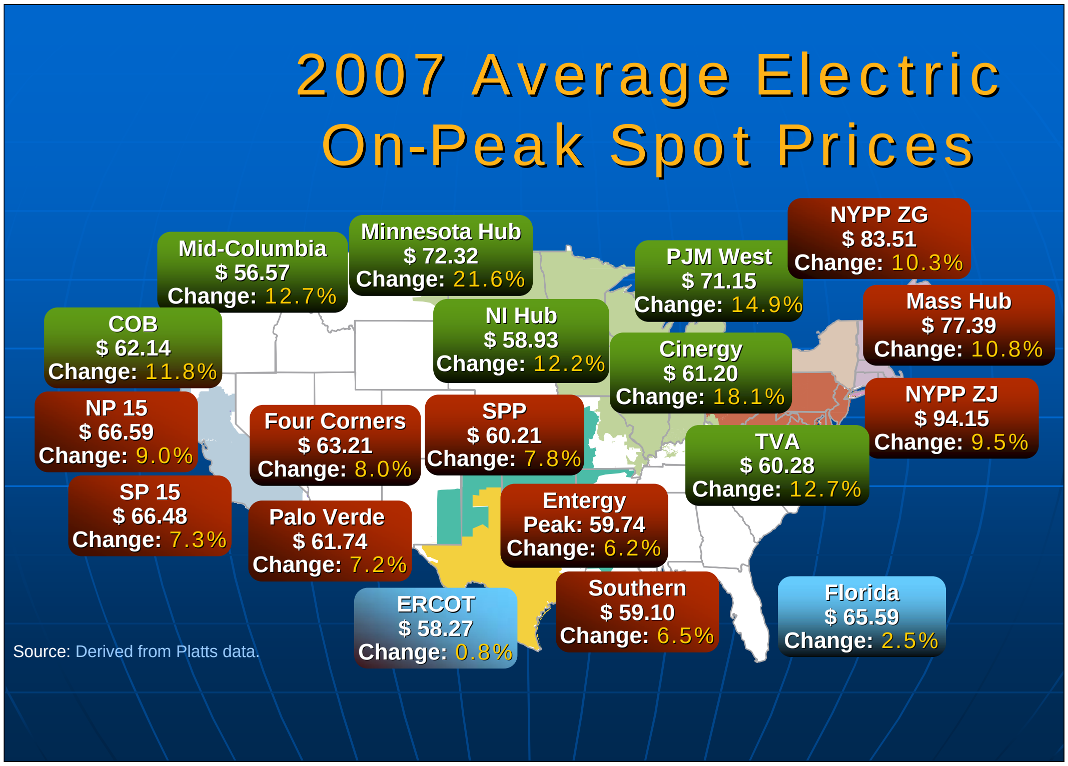
In areas with day-ahead RTO markets (ISO-NE, NYISO, PJM and MISO), ICE's spot market is primarily financial and operates within the day. There is little trading day-ahead. Fundamentally, it appears that market participants use the ICE market to hedge or speculate on price behavior during the day.

In the West (and ERCOT), the ICE spot market is fairly large and composed overwhelmingly of day-ahead, physical transactions. Bilateral spot markets appear to form the primary price discovery mechanism for day-ahead spot power transactions. There are many financial electric transactions on ICE in the West, but most are for longer terms.

And in the Southeast, the ICE spot market is also physical and traded day-ahead, but it is much smaller – less than one-fortieth the size of the Western ICE spot market. Based on ICE data, the Southeast appears to use bilateral spot markets to make minor changes in decisions otherwise taken within the major traditional utilities. Nonetheless, bilateral spot markets are important at the margin, and can become quite important during periods of system stress.



Electricity generation increased in almost all regions of the country in 2007, but the degree of increase varied considerably from one region to another. For example, New England, New York and California showed little increase, while the Southeast, the Midwest and – especially – the Rockies showed larger increases.

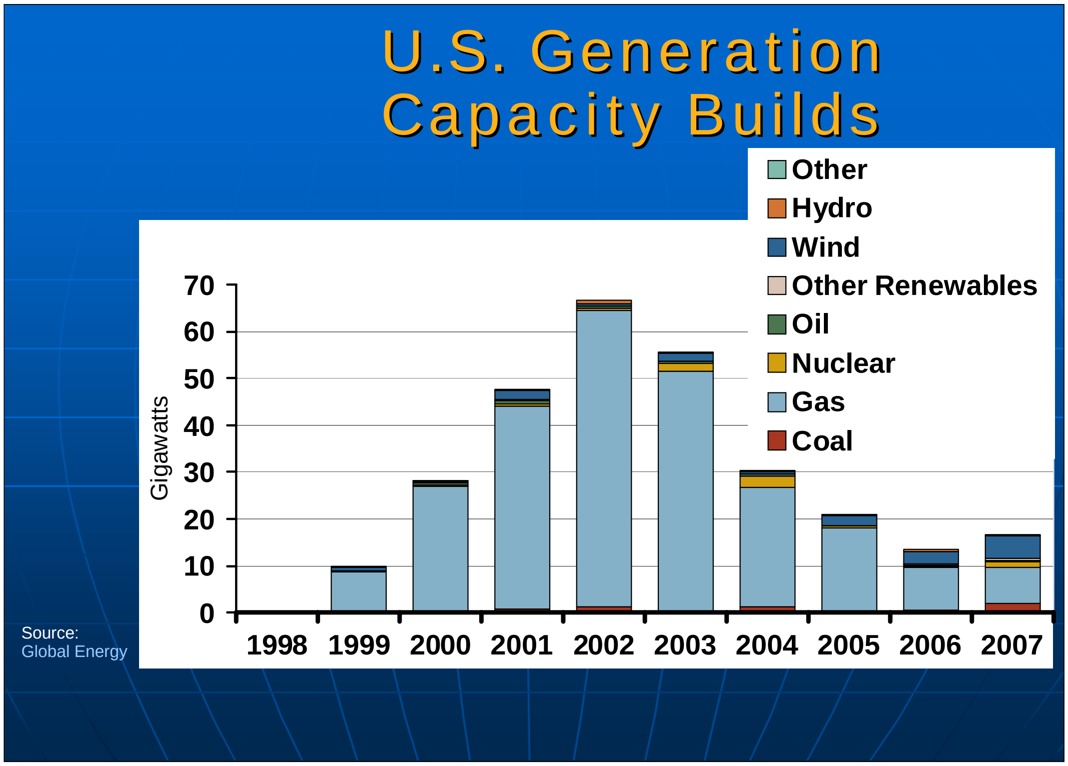


On-peak wholesale electric prices generally increased in 2007. A combination of moderate gas price increases and load growth meant that on-peak wholesale power prices increased by 6% to 11% at most pricing points, though in most regions, they remained below the hurricane-influenced levels of 2005.

In percentage terms, the highest price increases occurred in a region including MISO, PJM West and TVA. Several factors probably contributed to this result. For example, MISO made some additional transactions eligible to set the market clearing price, which lowered uplift while raising the market clearing price. PJM's market monitor reported that increasing loads increased prices by moving marginal generation further up the supply stack and that congestion had increased. Both factors probably affected MISO

as well.

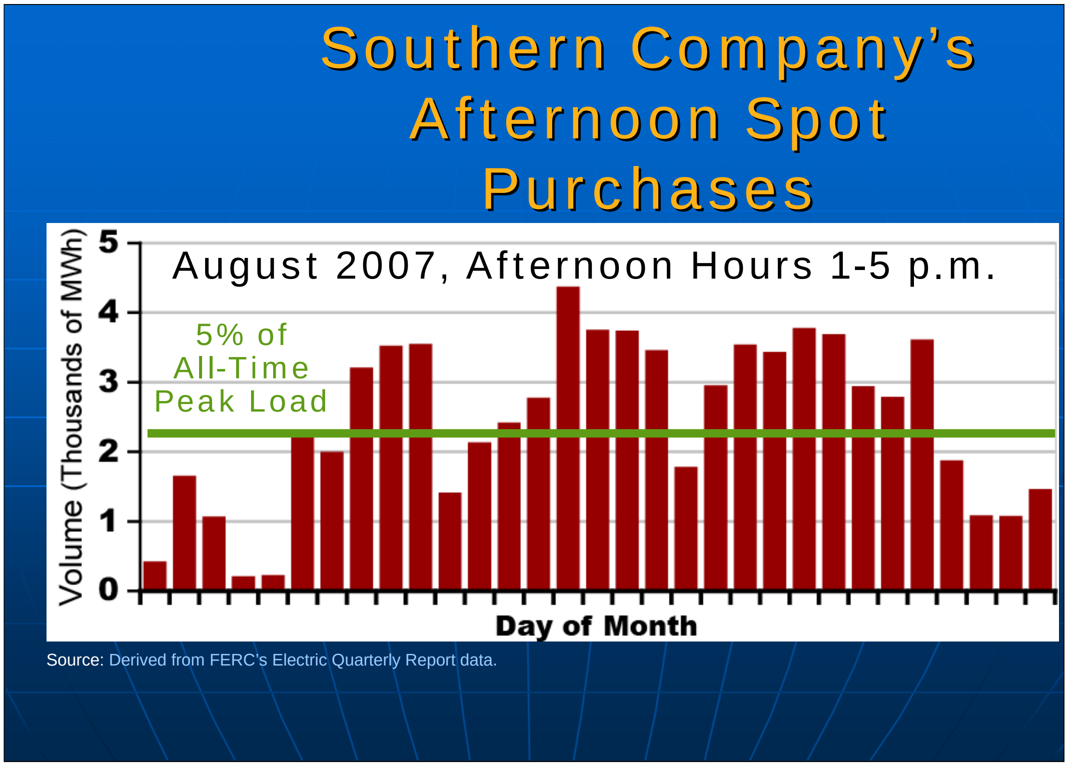
I'll also mention a couple of exceptions that stand out on the slide. In the Northwest, prices rose 12% to 13% – the additional increase arising from less favorable hydroelectric conditions. And ERCOT rose by only 1% because of a cool and rainy summer.



During 2007, the electric industry completed relatively little new generating capacity. What capacity increases there were came mostly from four sources:

- The Brown's Ferry nuclear plant in Tennessee was re-commissioned after being out of service for 22 years, accounting for about 7% of the overall increase in capacity.
- New natural gas units accounted for 7,500 MW of new capacity, 45% of the total.
- Coal plant additions were smaller, about 13% of the total.
- Wind units accounted for about 30% of the new capacity coming on line in 2007. So, wind and natural gas together account for three quarters of the additions. Among the incentives for investing in wind power are federal tax incentives and meeting the goals of renewable portfolio standards in many states. However, wind is an intermittent resource, often not available at peak.

The relatively slow pace of investment in new generation almost certainly reflects uncertainty about the future treatment of greenhouse gases, especially carbon dioxide. Developers canceled many proposed coal projects around the country in 2007.



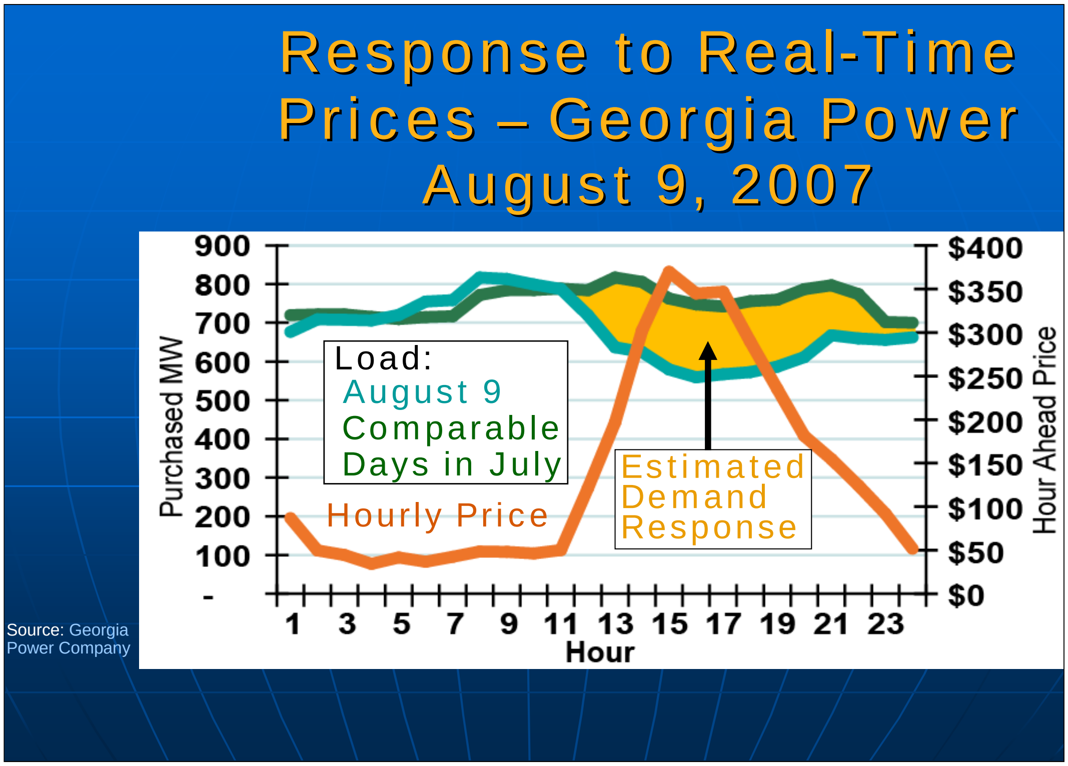
In 2006 and 2007, the American electric industry showed an impressive ability to address severe summer weather.

In 2006, the Northeast and Midwest faced a heat wave at the beginning of August. The region's RTOs successfully responded with various forms of scarcity pricing, demand response and emergency measures. Also in 2006, the West faced a long period of severe heat in July. Despite the prolonged heat, Western markets experienced a price spike on only one day. Otherwise, prices were relatively moderate and there was little or no disruption.

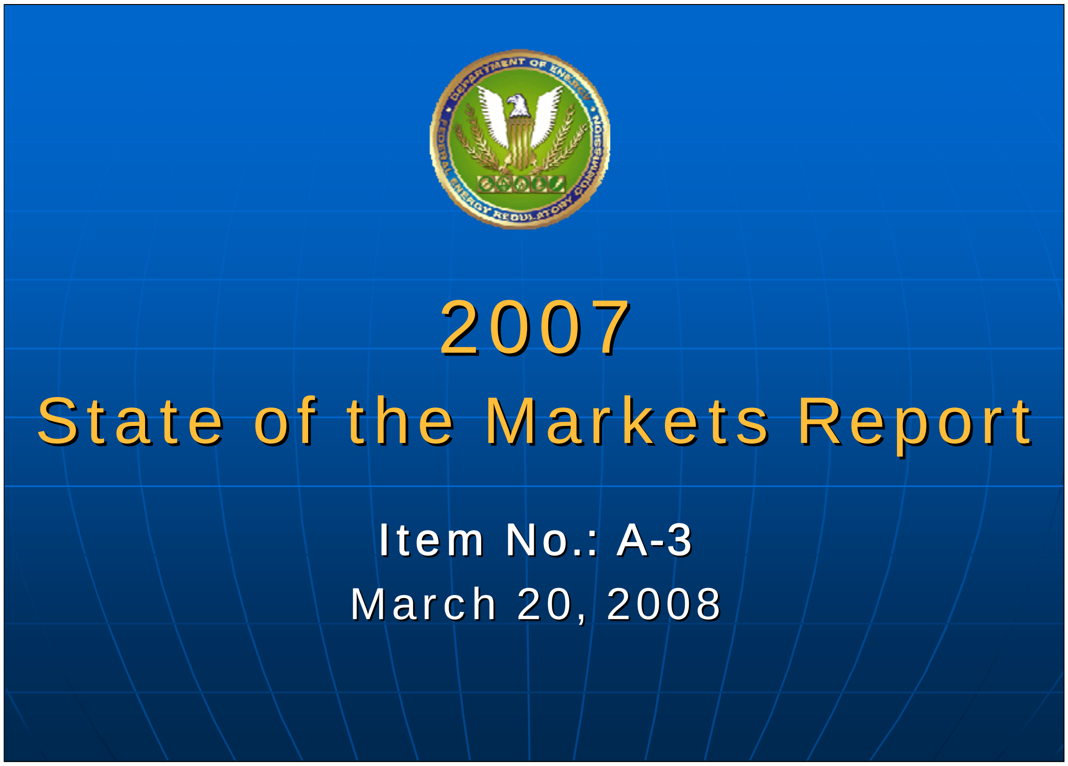
In 2007, it was the Southeast's turn. The region faced a heat wave for most of August, coupled with long-term drought that reduced hydropower resources and threatened to reduce some steam generation as well. As with other regions in 2006, the Southeast withstood the heat without major disruptions.

How did southeastern electric markets work during this period? We can see only limited information about spot wholesale markets in the Southeast. But over the last year, we have had several informal discussions about market developments with the Southern Company – and these have provided more of a window into the region than we had before.

Southern said that it used bilateral spot markets to help deal with the heat wave. Usually, Southern buys or sells less than 1% of its power on bilateral spot markets. Sometimes, it has no transactions at all. During August, however, as the slide shows, Southern increased its spot purchases, mostly in the day-ahead market. Indeed, EQR data show that Southern bought more than 5% of its power needs for some peak afternoon hours. These purchases show that the bilateral spot markets are serving a vital function, even in areas of the country where it is small overall.



Another key insight from the discussions with Southern is the practical importance of real-time pricing. Georgia Power's real-time pricing program for industrial customers lets customers choose whether to buy or not every hour, based on price. The chart shows how customer load in the program dropped during high priced hours on the peak price day (August 9), compared with loads on an otherwise similar day in July. Georgia Power estimates that real-time pricing reduced load for program participants by 23% during the most affected hour - about 1% of Georgia Power's overall load at the time. This reduction came at prices around $400/MWh, considerably lower than those reached when most demand-response programs were triggered in the Northeast during the 2006 heat wave.



That concludes our presentation on this year’s State of the Markets Report.
We welcome any questions.