



FEDERAL ENERGY REGULATORY COMMISSION

2010 State of the Markets

Item No: A-3
April 21, 2011

Good morning Mr. Chairman and Commissioners.

We are pleased to present the Office of Enforcement's 2010 State of the Markets report. The State of the Markets is staff's annual opportunity to share observations about natural gas, electric and other energy markets.

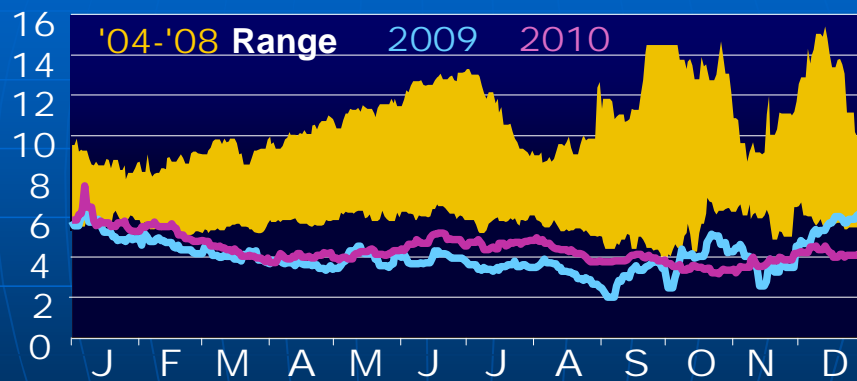
Before we begin, I'd like to mention that this presentation is based on opinions and conclusions of staff and not necessarily those of the Commission, the Chairman, or any of the individual Commissioners.

State of the Markets 2010

- Natural gas supply and demand reached record highs, while gas prices remained moderate throughout the year
- Pipelines adjust to new shale gas production
- Electric demand increased
- Electric capacity additions slowed

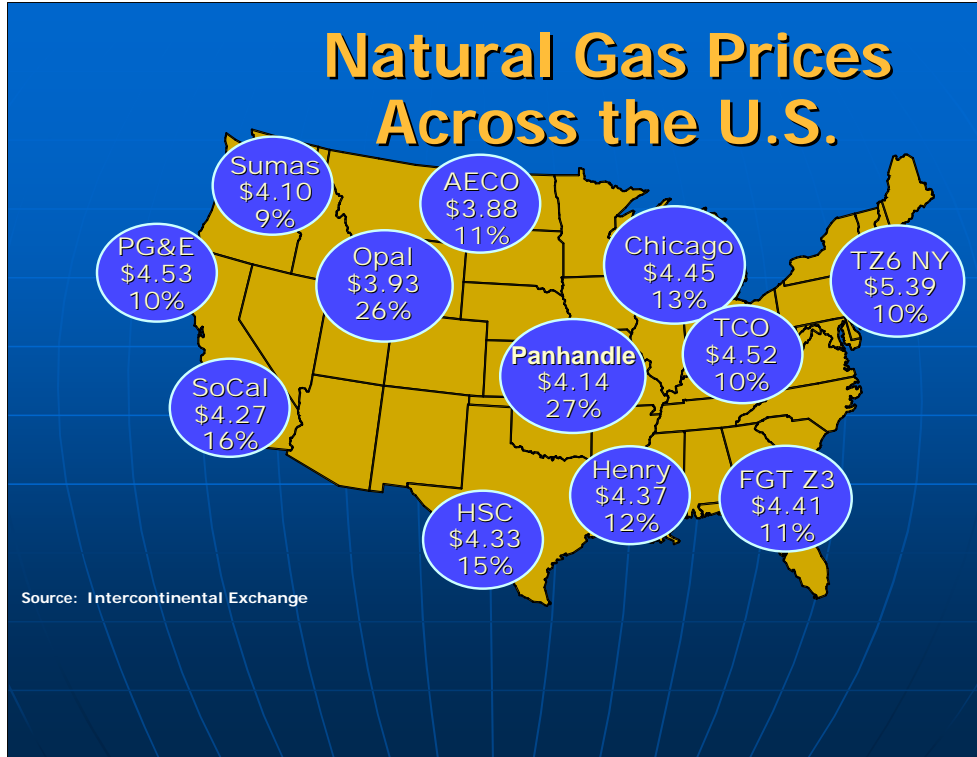
In 2010 we saw natural gas supply and demand set new records, while natural gas prices remained moderate through most of the year. We also saw regional changes in natural gas production and new infrastructure changing utilization along some key pipeline routes across the country. There was also increased demand in the power sector, but a decrease in the amount of power generation capacity added compared to prior years. Specifically, wind and natural gas-fired generation additions dropped off in 2010.

Henry Hub Natural Gas Daily Spot Price



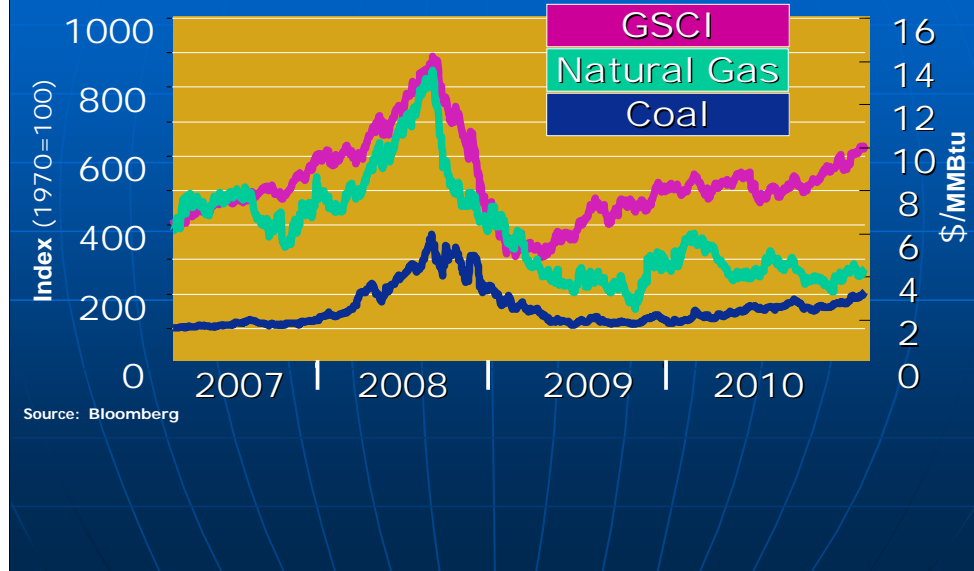
Source: Intercontinental Exchange

Though 2010 natural gas prices were up about 12 percent on average over 2009, they remained well below the levels of previous years. Natural gas demand increased in 2010 and was only partially offset by increased natural gas supply. Natural gas storage levels were high for much of the year and reached record levels in November. Outside of early winter 2010 and a few days in June, spot prices at the Henry Hub remained between \$3/MMBtu and \$5/MMBtu. By the end of the year, prices remained low despite a cold start to the winter.



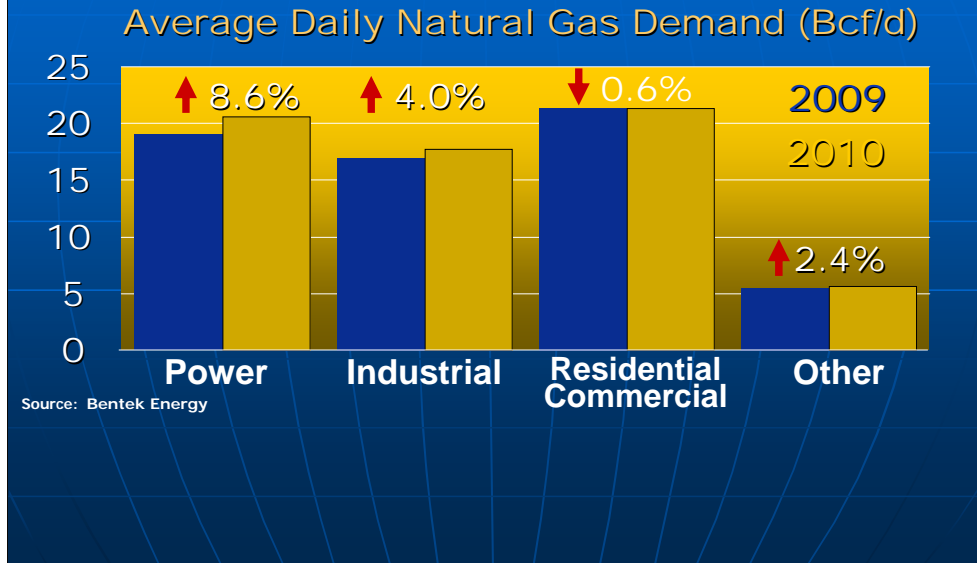
As at Henry Hub, average spot natural gas prices rose across the country. In last year's State of the Markets presentation, we highlighted the development of a national gas market due to increases in domestic production, added pipeline infrastructure and increased storage capacity. This trend continued in 2010, with regional price differences increasingly reflecting the variable cost of transport between hubs. Prices in the Rockies and Lower Midcontinent producing regions rose closer to the Henry Hub in 2010 as increased takeaway capacity to higher priced markets lifted local prices. The difference between natural gas prices in the Northeast and the Henry Hub fell as increased local production and pipeline capacity gave the Northeast more options to obtain natural gas.

Natural Gas Prices vs. Other Commodity Prices



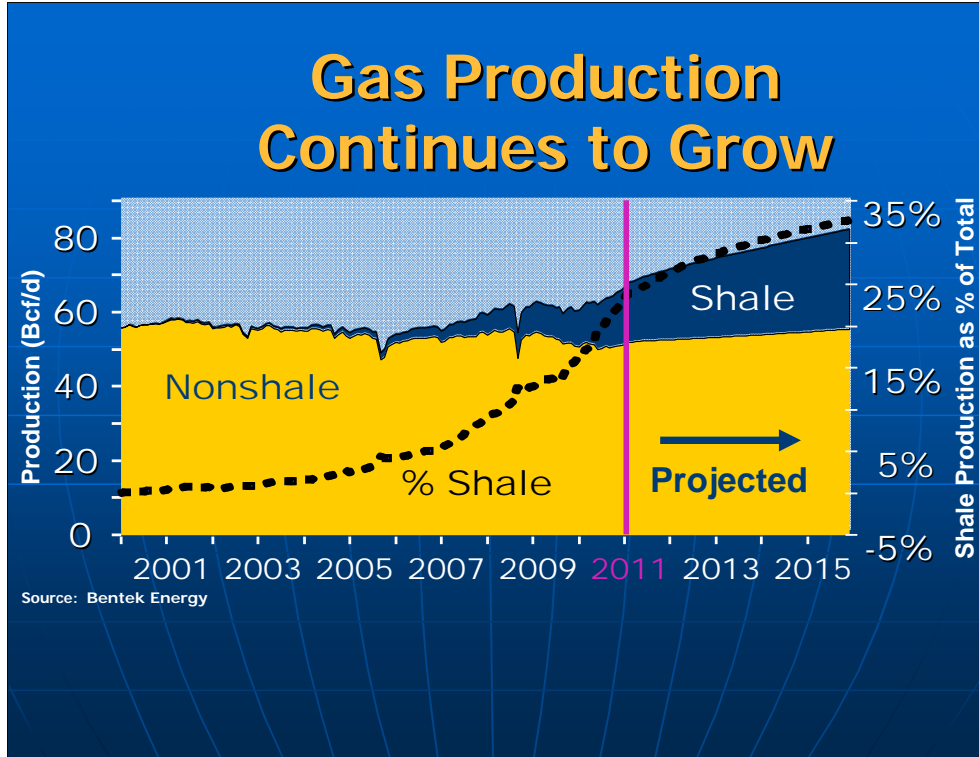
The course of natural gas prices in 2010 revealed an interesting new market dynamic. Through recent years, natural gas prices moved similarly with other commodities, represented here by the Goldman Sachs Commodity Index (GSCI). Yet as commodity prices have been generally increasing since the beginning of January 2009 (the GSCI has doubled in the last two years), natural gas prices have remained relatively flat. This is a result of several factors. Aside from a small amount of LNG imports, at present, the North American natural gas market is self sufficient and largely insulated from the international pressures that other commodities face. Strong domestic production growth, combined with added pipeline and storage infrastructure, have increased domestic supply and reduced geographic and seasonal price differences. And unlike in 2008, natural gas prices appear to be responding primarily to physical fundamentals, namely growing supply from lower-cost sources, rather than financial market influences. Also, the graph shows that natural gas prices and coal prices have been converging. This has led to some dispatching of natural gas-fired generation before coal-fired generation.

Natural Gas Demand Grows in 2010



Following several years of modest growth, U.S. natural gas demand increased 3.7 percent in 2010. This was driven by a recovering economy that boosted industrial natural gas demand by 4 percent and by strong growth in the power sector. There was virtually no growth in residential and commercial consumption.

Though weather conditions can affect year-to-year demand in the power sector, the use of natural gas to generate electricity has grown steadily in recent years and now accounts for almost one-third of total U.S. natural gas demand. Increased natural gas generating capacity utilization, the large growth in and lower production cost of proven natural gas reserves and a flatter forward curve have positioned natural gas generation to increase market share in the power sector. Natural gas is increasingly edging out coal as the most economical fuel for baseload power production in more parts of the country for longer periods during the year. This added approximately 1.1 Bcf/d to 2.8 Bcf/d on average to total U.S. natural gas demand over the course of 2010. Given current natural gas and coal prices this trend should continue in 2011.



U.S. domestic natural gas production grew steadily over the course of the year, from just over 58 Bcf/d in early January to more than 63 Bcf/d in late December, reaching record highs. This growth can be attributed to increased shale-gas production, which accounted for 23 percent of total U.S. production by the end of 2010, up from just 13 percent of total production two years before. Production from the Haynesville, Fayetteville and Marcellus basins alone grew more than 7 Bcf/d in the four years from January 2007 to January 2011. Some market analysts forecast shale-gas could account for one-third of total U.S. production by the end of 2015.

This production growth occurred in spite of continued low natural gas prices because much of the increase in natural gas production in 2010 was associated with natural gas liquids (NGL). Natural gas liquids include ethane, propane, butane and natural gasoline and can add a significant source of revenue to natural gas production, particularly because NGL prices have been increasing with the oil market. In some plays such as the Eagle Ford and North Barnett Shale in Texas, and the Bakken Field in the Dakotas, the breakeven cost for natural gas has fallen to zero, and natural gas has essentially become a byproduct of oil and NGL drilling. With this trend, we witnessed a shift in drilling from pure natural gas wells to wells that produce both natural gas and NGLs.

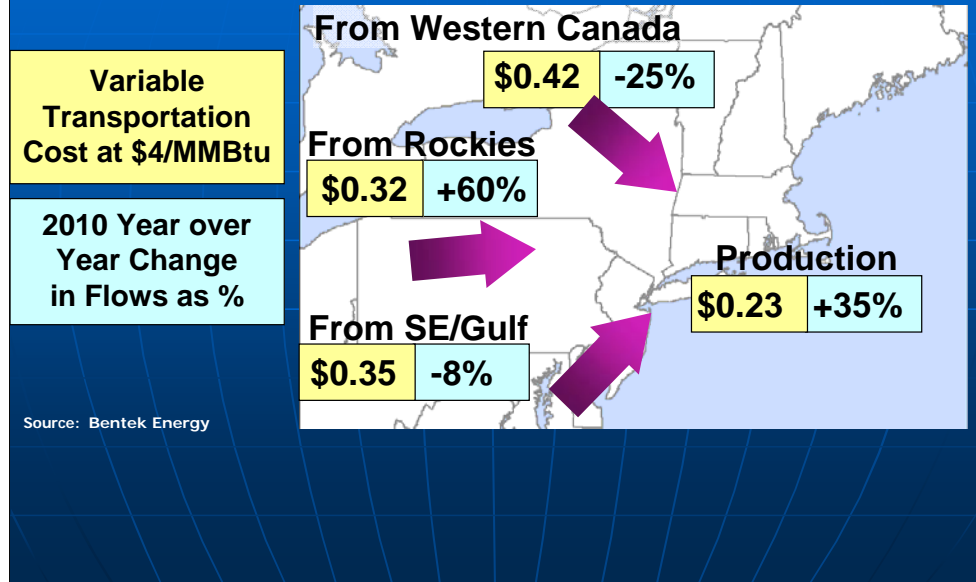
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Over 2010, there were renewed environmental concerns regarding air and water quality problems associated with both the increased level and methods involved with natural gas extraction, specifically the hydraulic fracturing method used in shale-gas drilling. The Environmental Protection Agency, at the direction of Congress, is undertaking "a study of this practice to better understand any potential impacts of hydraulic fracturing on drinking water and groundwater." The EPA recently submitted its draft study plan to the agency's Science Advisory Board, with the goal of understanding the relationship between hydraulic fracturing and drinking water resources from the beginning to the end of the drilling cycle, and expects initial research results by the end of 2012 and a final report in 2014.

Another aspect of the growth in onshore shale-gas is that the U.S. is less susceptible to disruptions in production from hurricanes in the Gulf of Mexico. However, we have seen instances of well freeze-offs that can have a significant though short-lived effect on onshore production.

Shale Growth Affects Pipeline Utilization



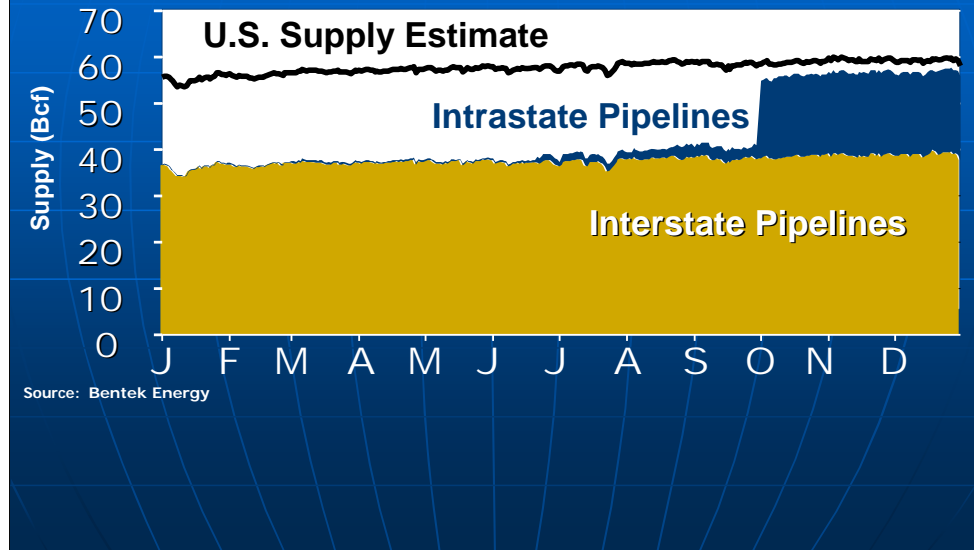
Regional changes in natural gas production and new long-haul pipelines are changing utilization along some key pipeline routes across the country. The 1.87 Bcf/d Rockies Express Pipeline, which completed its route from Wyoming to Ohio in 2010, displaced natural gas from Western Canada and to a lesser extent the Gulf Coast. That displacement has accelerated with the rapid growth of Marcellus natural gas production. U.S. natural gas is now being regularly exported to Canada via backhaul; a number of proposed new Northeast pipeline projects will export Marcellus natural gas to Canada.

U.S. pipelines at most risk for displacement include those flowing Midcontinent and Gulf Coast production to the Northeast and the TransCanada pipeline system into the Northeast.

In Canada, TransCanada filed for a reduction in its long-haul rates to try to keep long-haul customers, proposing to make up for lost revenues by increasing rates on short-haul customers. In the United States, both Columbia Gulf and Tennessee filed rate increase proposals, citing growing Marcellus production and a need to offer discounts on long-haul rates from the Gulf Coast to compete. These pipelines will likely see less utilization on pipeline segments between the Gulf Coast, the Midcontinent and the Northeast but will likely have higher short-haul utilization within the Northeast.

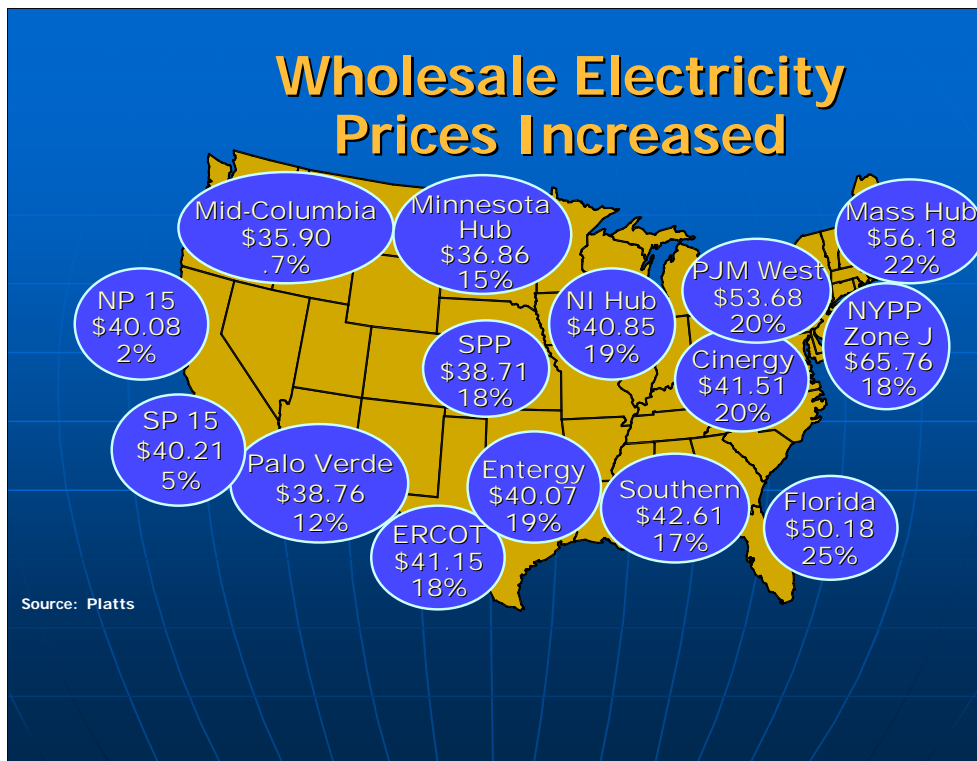
This is a trend we will be following as regional shifts in natural gas production continue to impact pipeline utilization on established long-haul pipelines with higher transportation costs.

FERC Order No. 720 Improves Market Transparency



FERC Order No. 720, implemented on October 1, 2010, required major non-interstate pipelines to begin posting daily nominated receipts and deliveries on their systems. The result was a sharp increase in market transparency. Prior to October 1, 65 percent of U.S. natural gas supply was visible to the market. After October 1 this increased to 95 percent, and we now know that intrastate pipelines account for approximately 18 Bcf/d of daily U.S. natural gas supply. This allows the market to estimate daily U.S. natural gas supply much more accurately. In Texas, observable production increased from 5 Bcf/d in the first half of 2010 to more than 17 Bcf/d after implementation of Order No. 720. We also observed more deliveries to power plants and industrial customers. Order No. 720 has successfully increased market transparency and the level of daily market information available to market participants, analysts and regulators.

I will now hand the presentation over to Lance Hinrichs to talk about developments in the electric markets.

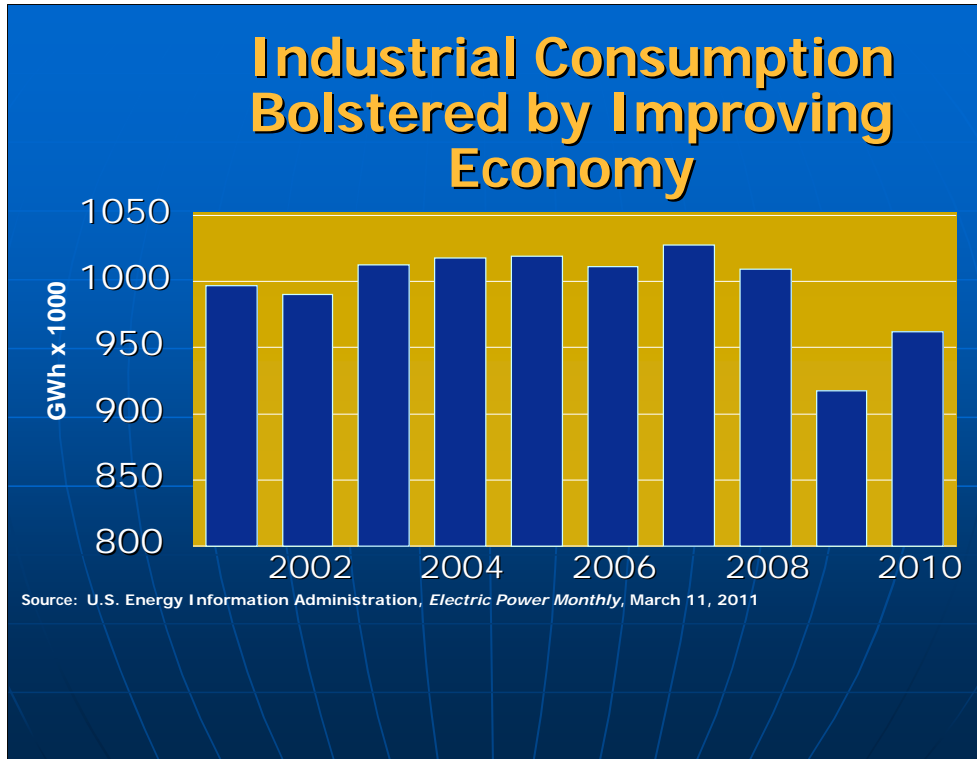


Last year we reported that 2009 wholesale electricity prices fell by half from the previous year. In contrast, 2010 peak hour prices were up almost 17 percent compared to 2009. Despite this increase, 2010 prices are still roughly 42 percent lower than 2008.

The 2010 price rise was primarily related to the previously mentioned increase in fuel price. However, higher power loads throughout most of the country also had an impact; making it necessary for operators to rely on higher cost generators

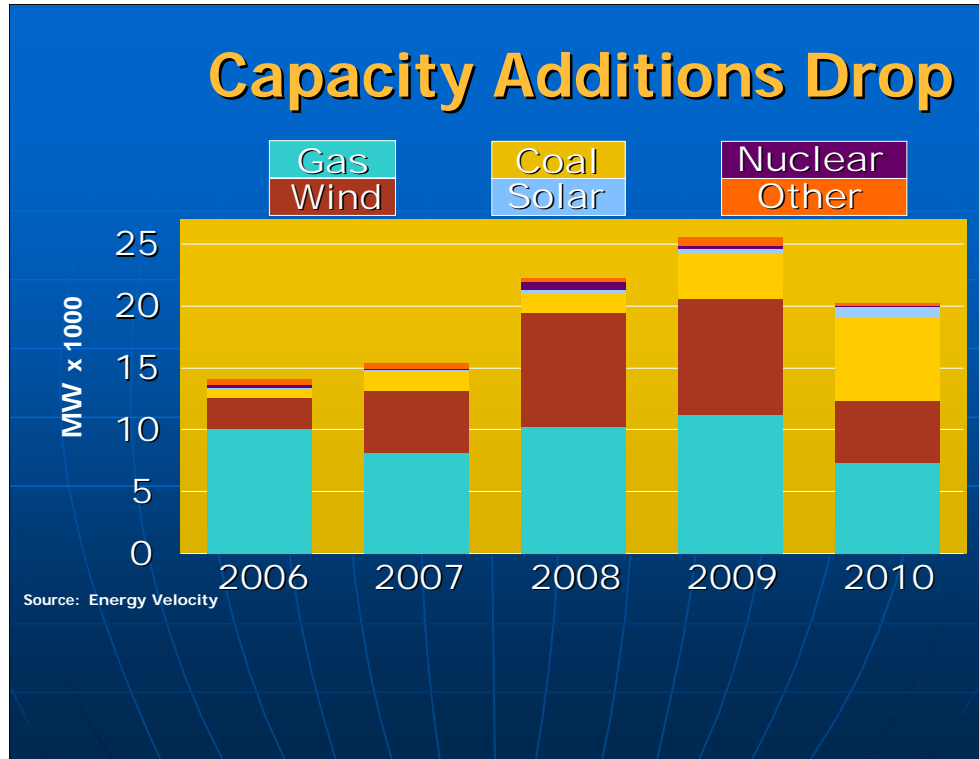
As this map shows, the increase in price was not uniform across the country. In the East, a hot summer, along with early signs of a moderate economic recovery, pushed up electricity demand. In PJM, for example, average load was up 4.7 percent. Overall, Eastern prices rose by nearly 20 percent.

In contrast, the West experienced a more modest increase in prices due to mild weather. Specifically, a relatively mild summer in California led to a decrease in load of almost 3 percent, compared to 2009. Late spring precipitation in the Northwest resulted in better than expected hydro generation output which also moderated prices and even resulted in negative off-peak prices, at the Mid-Columbia trading hub. Overall, prices in the West were up by 6 percent.



Consumption of electricity increased in 2010, in part, due to the improving economy. The recession helped to drive down consumption, from a high in 2007 to a low in 2009, and in 2010 we saw the initial signs of a recovery. Even though industrial demand has not returned to the earlier levels, it is consistent with the economy's 2.9 percent rise in gross domestic product in 2010.

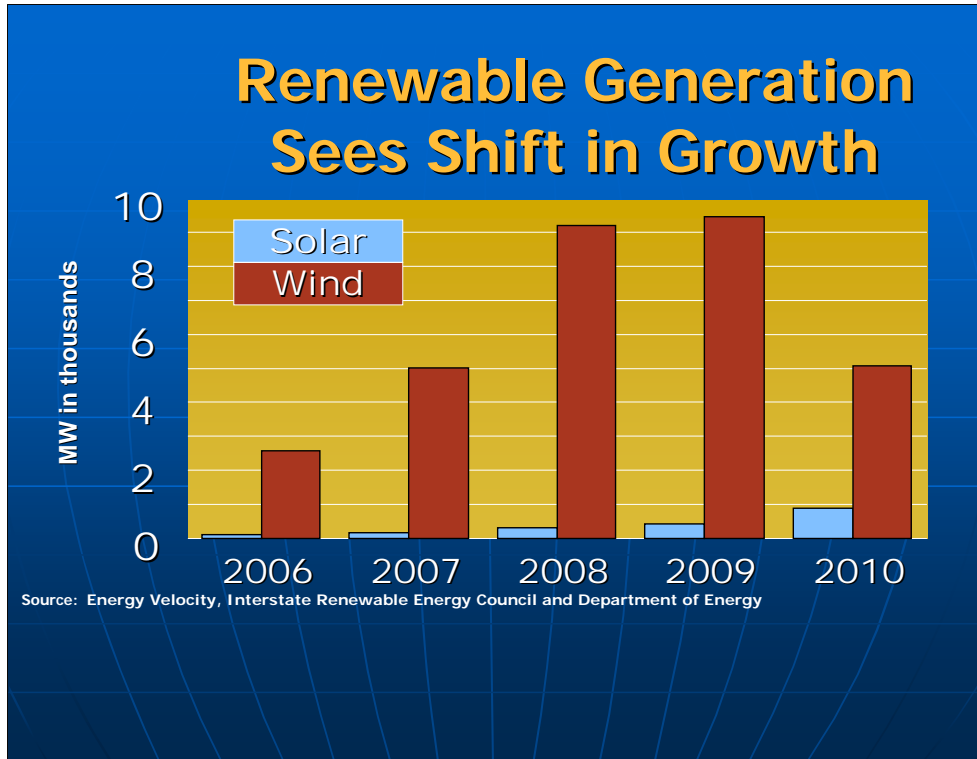
Not shown on this chart are the consumption trends for the residential sector, which are primarily driven by weather. After a relatively mild 2009, residential usage was up by 6 percent in 2010. In particular, the summer months were hotter than normal for all regions but the Pacific Coast states. In the Sunbelt, there was record heat and, as a result, the Southwest Power Pool and ERCOT set records for peak electric demand. Additionally, the winter months produced more heating degree days than normal in all sections of the country except for New England and the western states.



In 2010, we saw a drop in the amount of new electric generation capacity added compared to the prior year. Overall, plant additions were down approximately 20 percent in 2010, compared to 2009. This is consistent with the effects of a slowly recovering economy, sluggish power demand growth and tight credit in recent years.

While natural gas and wind plants have recently dominated the megawatt-capacity share of additions, there was an increase in the amount of new coal-fired generation in 2010. These new coal plants came from projects that were the product of a multi-year development process that was initiated when the economic signals for investment were quite different from today. Over the past four years, the relative fuel cost advantage for coal plants has decreased, coinciding with the previously mentioned increases in shale gas production. In contrast, the development timeline for natural gas and wind plants is appreciably shorter.

High capital cost, reduced load growth and plentiful natural gas supplies have slowed the development of new nuclear facilities. Over the last several years, the NRC received 19 applications to either construct or reserve sites for new plants. However, by the end of 2010, several of the developers requested that the NRC suspend review of their applications, and others have indicated that they will not immediately proceed with construction. Utilities in traditional markets are developing most of the nuclear plants that are still moving forward. In particular, the Southern Company and SCANA have started preliminary site work for new reactors at two different sites.



Renewable resource additions in 2010 were mixed.

For renewable capacity, wind was the leader, adding just over 5,000 MW. Despite a 15 percent drop in turbine prices and a continuation of federal tax incentives, this growth was roughly half the rate of the previous two years. It was primarily attributable to significantly lower natural gas prices and a weak investment environment. These conditions made it difficult for developers to sign long-term power-purchase agreements, which are an important consideration to project financing.

The Midwest ISO added the most wind generation, with an additional 1,500 MW, now bringing its system-wide capacity to more than 9,000 MW. This now rivals ERCOT as the region with the greatest wind capacity. The system-wide share of wind grew to between 4 and 8 percent of total energy output in MISO, SPP, and ERCOT

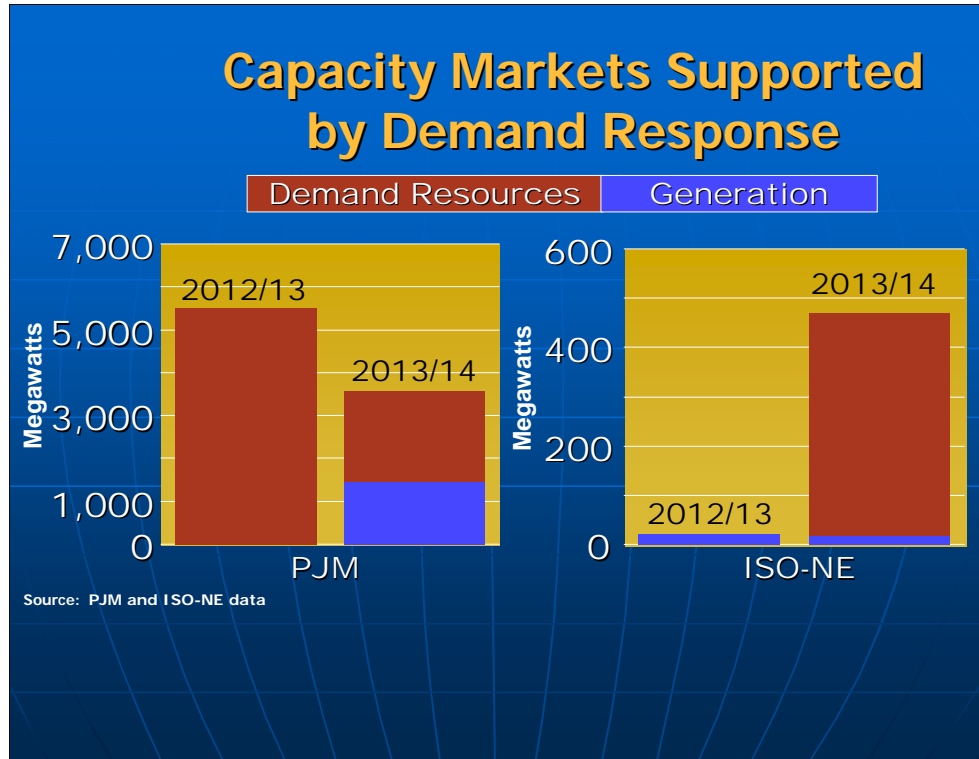
Solar projects grew robustly in 2010. Grid-connected solar photovoltaics increased at twice the rate of 2009, adding 883 MW. Five states dominated these additions: California, New Jersey, Nevada, Arizona, and Colorado, which together accounted for 64 percent of the new capacity. Separately, concentrating thermal solar power grew by 77 MW, the first big jump since the 1980s. In total, there is now more than 2,000 MW of grid-connected solar capacity.

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This growth has been supported by several factors, which include state-level incentives, favorable federal tax policies and a 21 percent decline in system costs. In particular, 16 states and Washington D.C. have provisions in renewable portfolio or energy standards that specify what percent of their target should be solar generation or distributed resources. Also, utilities tripled their photovoltaic installations to 242 MW, as they capitalized on changes that allow them to use federal tax credits and cash grants.

In response to the growth in renewables and their role in the markets, the Commission issued a Notice of Proposed Rulemaking for Variable Energy Resources in Docket No. RM10-11-000. In it, the Commission sought comments on the extent to which barriers may exist that impede the reliable and efficient integration of variable energy resources into the grid, and whether reforms are needed to eliminate those barriers.



RTO capacity markets provide a means for load-serving entities to procure resources to meet forecast load and allow generators to recover a portion of their fixed costs. In PJM and ISO-NE, capacity commitments are for a three-year period into the future. NYISO conducts capacity auctions for the upcoming season in the form of semi-annual seasonal strip auctions.

Despite a modest capacity price increase in 2010 for PJM, capacity prices have generally been steady or decreasing for the forward delivery years 2012-13 and 2013-14 for both PJM and New England. Load growth rates forecast for the forward years in PJM and ISO-NE, a key input for determining when new capacity will be needed, have remained relatively flat or declined, reflective of modest economic growth. In the auctions conducted last year for the forward delivery period of 2013-2014, PJM's RTO-wide price was \$843 per MW-month, with locational prices higher in the eastern part of the region. This was up 68 percent from the auction for the 2012-2013 delivery year, but down 75 percent from the auction conducted the year prior. ISO-NE's price was \$2,951 per MW-month, unchanged from the 2009 auction for the 2012-2013 delivery year.

For the auctions held in 2010, demand resources, that is demand response and energy efficiency, accounted for much of the incremental capacity for the forward periods. In PJM, net of retirements or deratings, 60 percent of new, incremental capacity committed was associated with demand response. In New England, 96 percent of the new capacity commitments were also associated with demand resources.

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Turning to New York, the summer peak load forecast for the state was down 450 MW or approximately 1 percent less than the previous year. Further, in 2010, NYISO saw a 900 MW net increase in capacity resources over the 2009 level. That, combined with a 130 MW increase in demand response, resulted in a slight decrease in capacity prices for 2010, when compared to 2009. Summer strip prices for New York State were \$2,470 per MW-month, down 18 percent compared to the prior summer.

New York City, a notable load pocket, had a large generator discontinue operations, and capacity prices for the summer capability period increased, as anticipated. Demand-response resources in the city remained important to the supply-demand equation, with more than 480 MW of demand response capacity offered at auction, which is about 20 percent of all demand-response resources in the NYISO.

RTO Market Rule and Design Changes

- SPP's Integrated Transmission Plan (ITP) approved
- CAISO new category for policy-driven transmission approved
- ERCOT commences its nodal market

Last year, the Commission approved a number of RTO market rule changes on topics ranging from transmission planning and cost allocation to capacity market mitigation measures. For example, the Commission approved SPP's Integrated Transmission Plan (ITP) where SPP conducts 20-year, 10-year and near-term assessments to determine transmission needs particularly for higher-voltage facilities. The Commission also approved the CAISO's tariff proposal to create a new category of policy-driven transmission facilities to meet policy requirements and directives.

In Texas, ERCOT launched its nodal market redesign on December 1st. This market is, of course, not regulated by the Commission; however their design is similar to several of markets that we oversee and the Division of Market Oversight will be following these developments to observe their results. The major upgrades to the ERCOT model include a transition from a four-zone pricing model to one with 8,000 nodes and, also, the introduction of both a day-ahead market and congestion revenue rights, which are similar to financial transmission rights, or FTRs.

That completes our presentation. We are available if you have any questions.



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