Slide 1


Good morning Mr. Chairman and Commissioners.

We are pleased to present the Office of Enforcement's 2011 *State of the Markets Report*. The *State of the Markets Report* is staff's annual opportunity to share our assessment on the natural gas, electric, and other energy markets.

*The presentation is based on conclusions of the staff and not necessarily those of the Commission, the Chairman or any of the individual Commissioners.*

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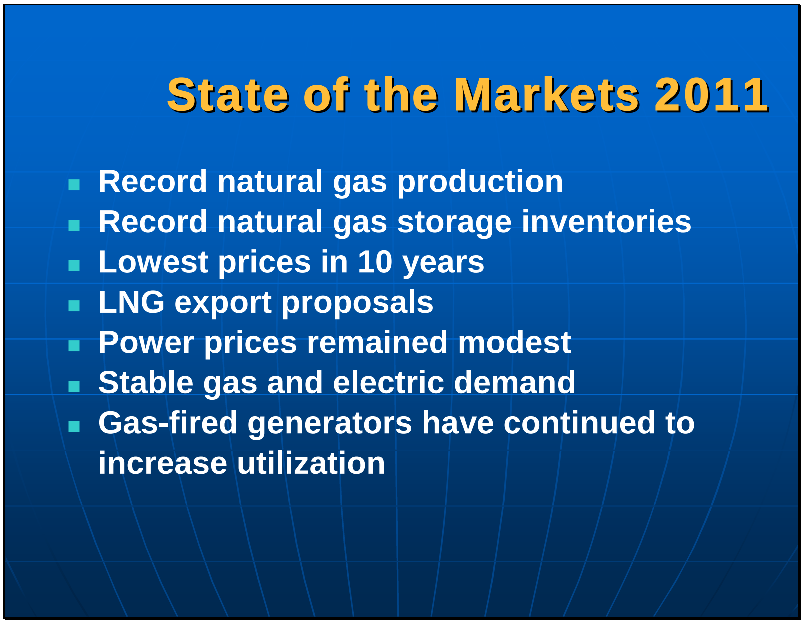


Natural gas production reached an all time record in 2011, surpassing levels last seen in the 1970's. Growing supply outpaced demand, which led to record high natural gas storage going into the 2011/2012 winter and natural gas prices fell to lows not seen since the early 2000's. Plentiful natural gas supply and low prices led to talk of the need to develop new domestic and foreign markets for natural gas and in 2011 seven LNG export projects were proposed in the U.S. with almost 14 Bcfd of capacity. The electric markets also experienced low prices as fuel costs fell and demand remained stable. Changes in the pricing relationship between natural gas and coal-fired generators caused a fundamental shift in the utilization of these plants, with natural gas plant production increasing and coal plant output falling.

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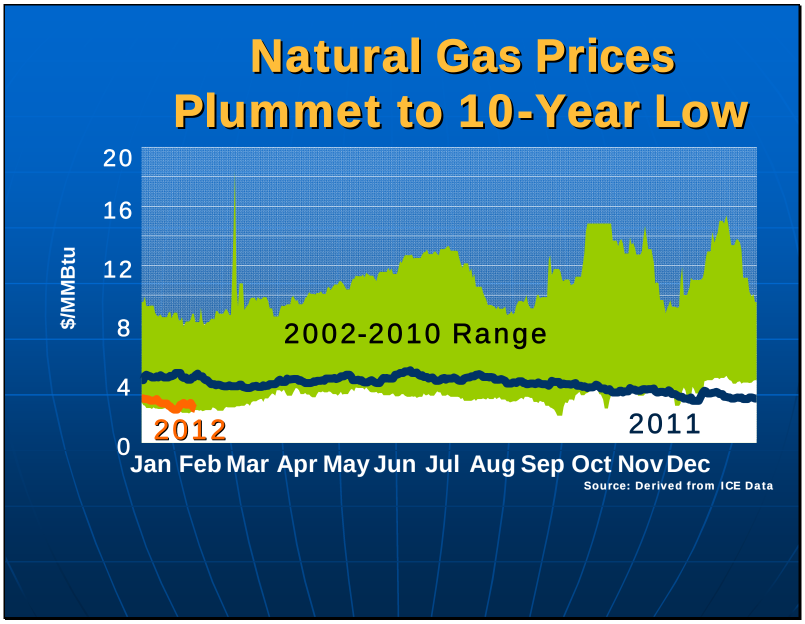


In this slide, we compare the current Henry Hub natural gas spot price (shown in red) to the ten-year range (show in green) to illustrate how prices fell below that range towards the end of 2011. In 2011, natural gas prices at Henry Hub were down about 9% over 2010. The price of natural gas fell from the mid- $4/MMBtu at the beginning of the year to under $3/MMBtu by December. The price remained at the $3/MMBtu level through the end of the year and reached parity with Central Appalachian coal.
The most recent Nymex forward curve for natural gas shows that the market anticipates that prices at Henry Hub will remain under $4/MMBtu through 2014. Some natural gas producers have voiced concerns that declining revenues due to low natural gas prices will affect their ability to explore for and produce natural gas. We have already seen some producers announce plans to cut back natural gas production and drilling in gas only shales while increasing drilling in shales rich in natural gas liquids. These announcements and possible impacts on production are trends we will follow closely in 2012.

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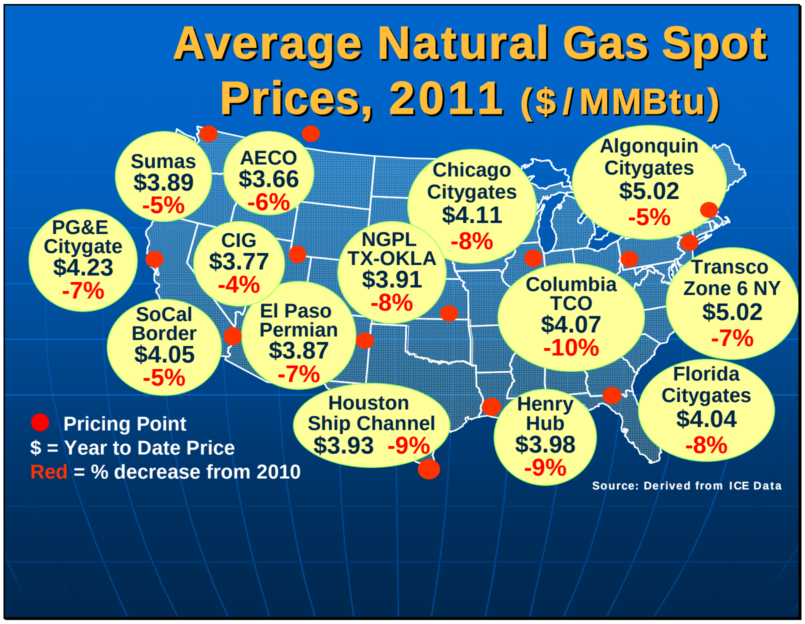


All pricing points declined in 2011. Average natural gas spot prices declined across the country by around 7% in 2011, as shown in the map. This winter was the warmest in 60 years and the Northeast, which usually sees the highest winter prices, saw no sustained price spikes. The Transco Z6 NY price for this winter averaged $4.25/MMBtu with a peak at only $12/MMBtu, whereas last winter, prices averaged nearly $7/MMBtu and peaked in December 2010 at $20/MMBtu.

New pipelines completed during 2011 linked growing supply sources to markets and contributed to shrinking regional price differences. In some cases, the market price of natural gas between regions declined to less than variable transportation costs. When prices drop below the variable cost of transportation, it becomes uneconomical to move natural gas to try to capture price differences between pricing points.

We have also seen a decline in the seasonal difference between winter and summer natural gas prices. Falling seasonal spreads reflect increased production and storage capacity, as well as greater year-round use of natural gas by power generators. This decline has developed over the past several years and we expect the trend to continue.

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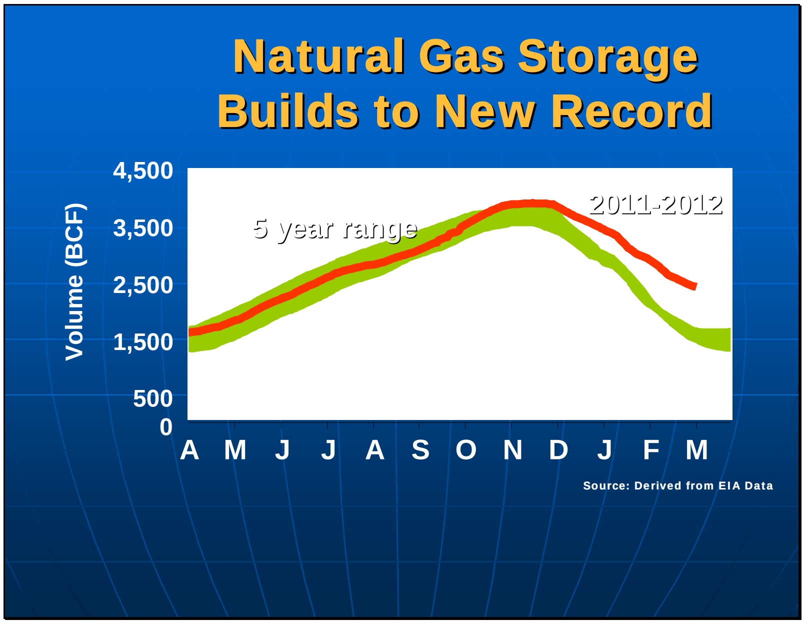


The recent warm winter, relatively low natural gas demand, and strong production exacerbated the current oversupply in the market. By the end of March, natural gas in storage was over 50% higher than the 5-year average which is shown in green on the graph. Natural gas in storage has never been at such high levels going into the spring and this will help inventories rebuild for next winter.

Although very high storage levels so early in the refill season indicate a need for additional storage, market conditions do not generally support the building of new storage. As mentioned in the last slide, winter-summer gas price spreads are at historically low levels and barely cover the cost of storing gas.

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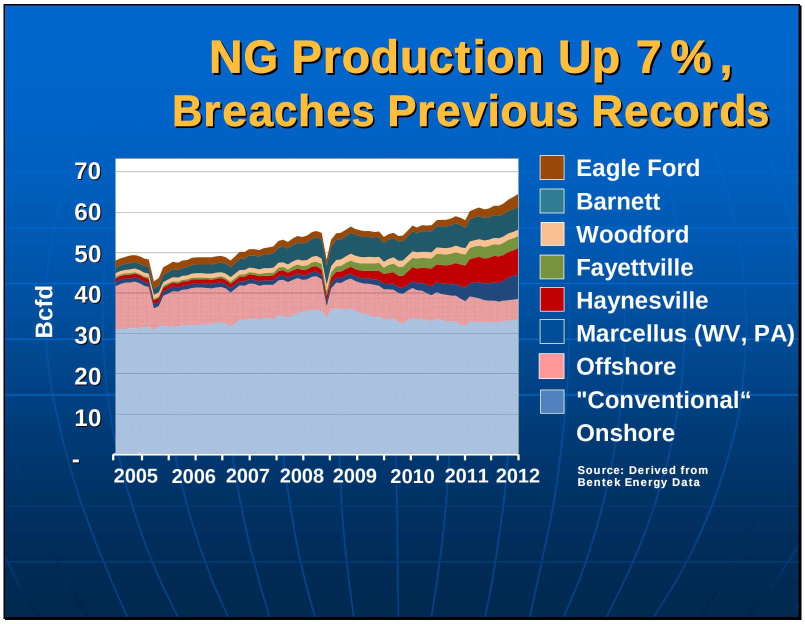


This slide shows natural gas production over the last seven years by source. Dry natural gas production grew 7% in 2011 to 65 Bcfd, surpassing an all-time record last set 25 years ago. Growth was primarily driven by robust on-shore shale gas production, which accounted for a third of total U.S. dry natural gas production by December 2011. This is up from 23% the previous year and just 13% three years ago. Dry gas shales, such as the Haynesville in North Louisiana, the Fayetteville in Arkansas and the Barnett in the Dallas/Fort Worth area, remained the largest producing shales in 2011. However, the fastest growing shales were found in the liquids-rich shale basins. The Marcellus Shale is a liquids-rich play in parts of Pennsylvania and West Virginia and production doubled over the year to nearly 6 Bcfd by the end of 2011. Production from the Eagle Ford Shale in South Texas grew 64% to 3 Bcfd over the same period, the highest growth of any shale. Some Eagle Ford wells produce as much as 70% natural gas liquids, which can double profitability compared to a gas-only well. The rapid increase in natural gas liquids production outstripped liquids processing and takeaway capacity in many regions, resulting in development and production bottlenecks for both natural gas and liquids. The liquids infrastructure in the Appalachian region was not designed to handle the volumes produced by the Marcellus Shale. The Eagle Ford Shale in Southeast Texas faces similar problems. Industry plans to add over 700 thousand barrels of fractionation and processing capacity and 1.3 million barrels per day of liquids pipeline takeaway capacity by 2014 to alleviate these bottlenecks.

Low prices and the drive to tap shale gas reserves have touched off a race to reduce drilling costs and improve rig operating efficiency. These improvements resulted in production increases even as the natural gas rig count declined. In 2011, the natural gas directed rig count dropped 6%, even as production increased. There are many shale gas wells that have been drilled but not completed because producers are waiting for higher prices. This will enable gas production to come on-line quickly as market conditions warrant.

Concerns regarding environmental issues associated with hydraulic fracturing remained at the forefront in 2011. At the federal level, the Environmental Protection Agency continues its study of the relationship between hydraulic fracturing and drinking water with its final study plan released in November 2011 and the final results not expected until 2014. At the state level, actions on fracking range from outright bans, such as the one in the New York City watershed, to the reassessment of current regulations in Ohio, as that state prepares for oil and natural gas development in the Utica Shale. There have been some reports of increased flaring levels of gas associated with the increase in oil production, but these are mostly a localized phenomenon. The overall level of flaring in the U.S. in 2010 (last year available) remained less than 1% of dry natural gas production, essentially unchanged from the average amount flared for the last 30 years.

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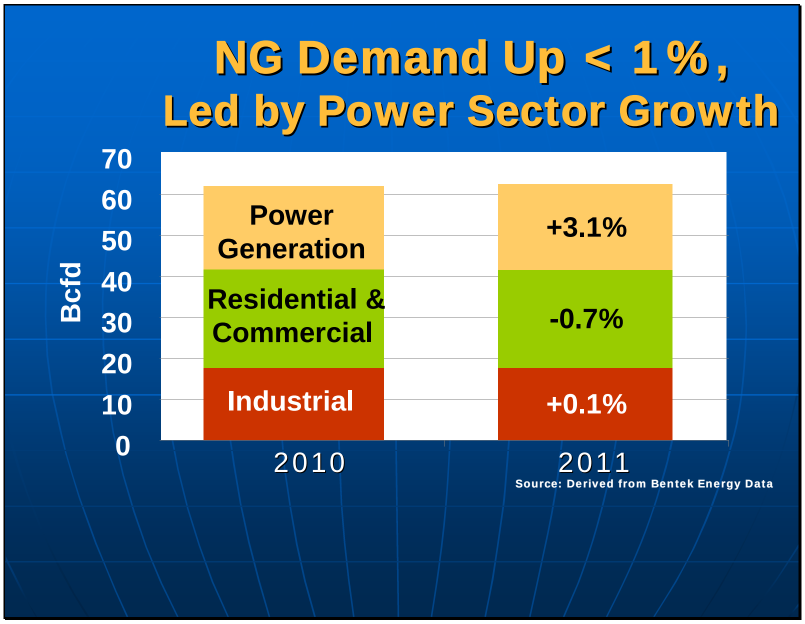


U.S. natural gas consumption in 2011 was up less than 1% over 2010. As shown, most of the growth came from natural gas-fired power generation, which was up slightly more than 3%. There was virtually no change in industrial natural gas consumption, and residential and commercial use fell 0.7%. However, while overall natural gas consumption varies year to year, strong growth in natural gas-fired power generation supported 10% growth in consumption over the last 10 years as Lance will discuss in more detail later in the presentation.

The greater reliance on natural gas has increased the importance of coordination between gas-fired generators and the natural gas pipeline companies that supply them. Concerns about coordination have been particularly strong in the Northeast, which is heavily dependent on natural gas and has experienced coincident peaks in both electric and natural gas demand during the winter season. It can also be a concern in parts of the Southwest that lack robust storage infrastructure. Also, upcoming coal plant outages for emission retrofits are expected to lead to greater use of natural gas-fired plants. Regional grid operators continue efforts in areas of planning, reliability and market operations.

Over the past year, as focus has increased on gas-electric coordination, natural gas and electric companies have launched initiatives such as enhanced communications between the various industry segments including generators, RTOs, and pipeline companies. In February 2012, the Commission issued administrative docket AD12-12 requesting comments on the issue of natural gas and electricity interdependence. Approximately 80 interested entities submitted comments, and commission staff is currently reviewing these submissions.

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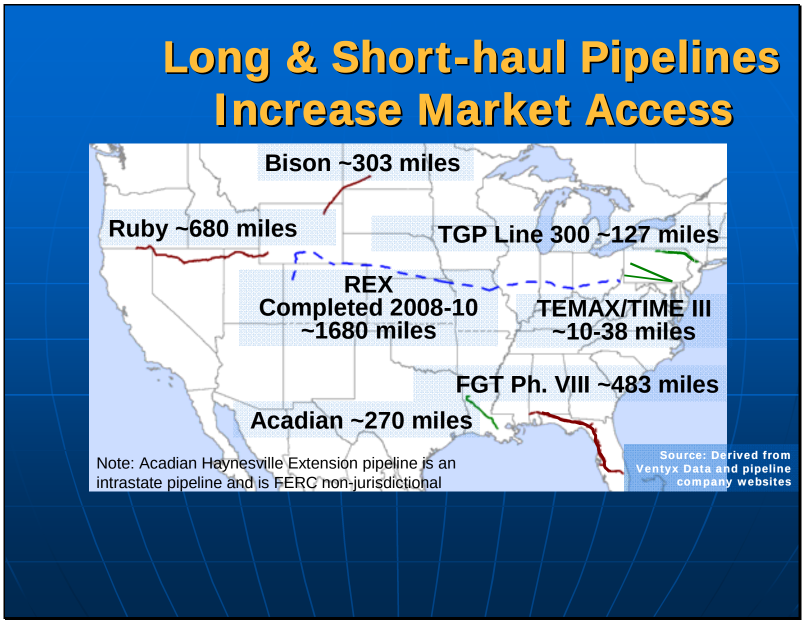


Last year transportation capacity values dropped on many long-haul pipelines as strong production growth in the Marcellus and other shale basins displaced some natural gas flows from traditional supply basins. For example, we saw Rockies natural gas flows to the Northeast on Rockies Express Pipeline (REX) decline more than 40% since early November 2010, from 1.7 Bcfd to 1 Bcfd. The decline was so severe that S&P reduced REX's credit rating. The downgrade is the result of persistent low profitability in shipping Rockies natural gas eastward, which has occurred because Rockies natural gas has been displaced in the Northeast by increased flows of less-expensive Marcellus Shale gas from Pennsylvania. Also, the new Ruby pipeline competed with REX providing Rockies producers access to a more profitable market in Northern California. S&P said that lower profitability now has increased the recontracting risk on REX as well. As with the Rockies, traditional U.S. Gulf Coast supplies have been displaced by largely liquids-rich Mid-Continent production.

In 2011, FERC jurisdictional natural gas pipeline companies added roughly 2,100 miles of new pipe or about 9.3 Bcfd of transportation capacity, while major intra-state pipelines added another 400 miles of new pipe and 4.7 Bcfd of transportation capacity. The six largest projects, shown on the map, accounted for 57% of new transportation capacity. Major projects include Ruby Pipeline, Florida Gas

Transmission Phase VIII Expansion and the Bison Pipeline. In 2011, pipeline developments shifted to projects focused on relieving local bottlenecks in new producing basins rather than long-haul pipelines. Most are located in the Northeast and Southeast and include the Tennessee Gas Pipeline Line 300 Expansion, the Texas Eastern TEMAX/TIME III project and the Acadian Haynesville Extension, an intrastate pipeline which feeds into the Henry Hub.

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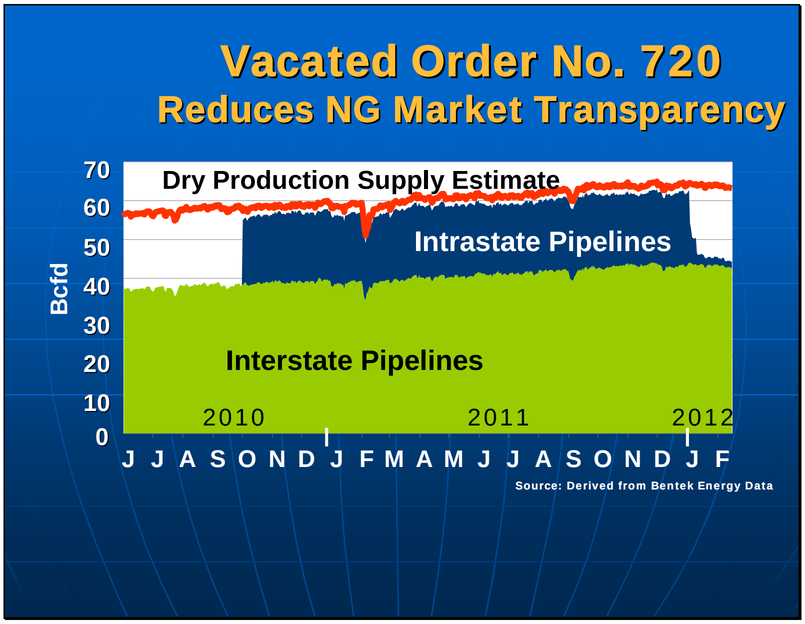


FERC Order No. 720, issued in October 2010, required major non-interstate pipelines to post daily nominated receipts and deliveries on their systems, the blue area of the graph. This resulted in a sharp increase in market transparency during 2011, with 97% of daily dry natural gas production visible to the market through pipeline receipts. Order No. 720 data made visible to the market daily natural gas production from some of the fastest growing shale plays. Demand visibility also increased significantly with implementation of Order No. 720. Prior to Order No. 720, the market did not have thorough information on the intra-state pipeline customer mix. For example, the amount of daily natural gas consumption from industrials or power generators in markets served predominantly by intrastates was not visible.

The Order No. 720 postings also allowed the market to see the impact of daily changes in natural gas supply and demand and effects on interstate price formation and fundamental market dynamics. For example, in February 2011, Order No. 720 postings enabled market participants to quickly assess the regional extent and impact of natural gas well freeze-offs as shown in the graph by the sharp dip in intrastate pipeline flows during February 2011.

In 2011, the Fifth Circuit Court of Appeals vacated Order No. 720 and most non-interstate pipeline postings ceased at the beginning of 2012. Now the market is only able to observe about 70% of daily changes in dry natural gas production and even less demand.

Recently many producers announced a dial back of natural gas production in response to low natural gas prices. With the loss of Order No. 720 data and with it producer deliveries into intra-state pipelines, it has become more difficult for market analysts to assess whether announced *well shut-ins* are actually occurring and if so, what affect they are having on market fundamentals. Less information usually injects greater uncertainty, price volatility, and risk into markets.

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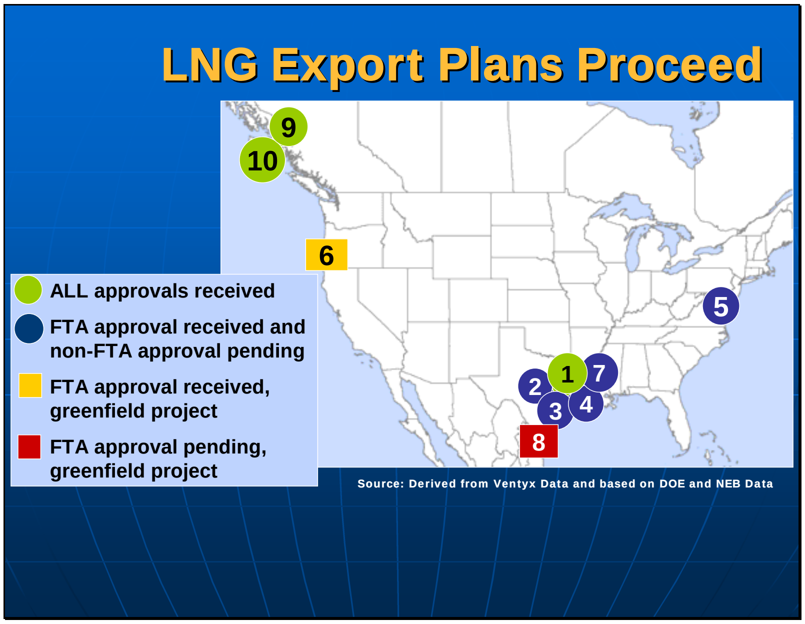


U.S. producers are seeking new foreign markets for growing supply and nearly 14 Bcfd of LNG export capacity was proposed in 2011 at various locations shown on the map. To put this into perspective, 14 Bcfd is about 21% of average daily U.S. natural gas production. EIA recently completed an assessment of the domestic price impact of U.S. LNG exports and concluded that U.S. natural gas prices could rise 9% at 6 Bcfd of exports and 11% at 12 Bcfd. A number of other studies have also analyzed various U.S. LNG export levels, with some showing no appreciable effect on prices and others showing a greater impact than EIA.

Cheniere Energy's Sabine Pass LNG, which has been approved by the Department of Energy to export domestically produced gas as LNG, is the furthest along with 90% of its proposed export capacity contracted by buyers in Korea, India and Spain. These buyers are likely willing to pay a price premium for the security and diversity that the U.S. natural gas market provides. So far, the Lower 48 has only re-exported small quantities of previously imported LNG. In its 2012 Annual Energy Outlook forecast, EIA projects that U.S. LNG exports will begin in 2016 at 1.1 Bcfd, doubling to 2.2 Bcfd by 2019.

I will now turn the presentation over to Lance Hinrichs to discuss developments in the electric markets….

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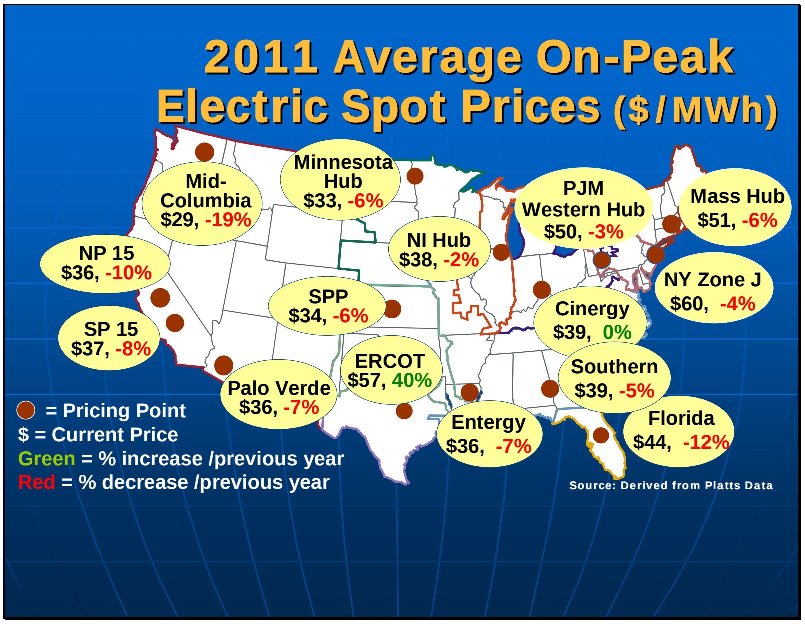


Power prices in 2011 were down throughout the U.S., with the exception of the ERCOT RTO and the Cinergy trading hub. This largely tracked the drop in natural gas prices that Valeria described and highlights the role of natural gas as the marginal, or price setting, fuel in most markets. On average, nationwide power prices were down 0.5% from last year, despite a warmer than normal summer.

Prices in the East were between 3 to 12% lower, primarily due to the lower natural gas prices. Western power prices fell between 7 and 19% supported by the robust hydroelectric output in the Pacific Northwest that was 27% above the 5-year average. The most dramatic change occurred in ERCOT, where prices rose by 40% due to extreme summertime heat that set a record breaking 41 straight days at or above 100 degrees. As a result, in August, there were 9 days in which ERCOT's energy-only market saw day-ahead prices rise to the $3,000/MWh price cap. This was in contrast to the Southwest Power Pool (SPP) region, which also experienced a hot summer. However, prices in the SPP region fell by 6%, primarily due to a robust capacity surplus and power imports of 2 to 3 GW during peak periods.

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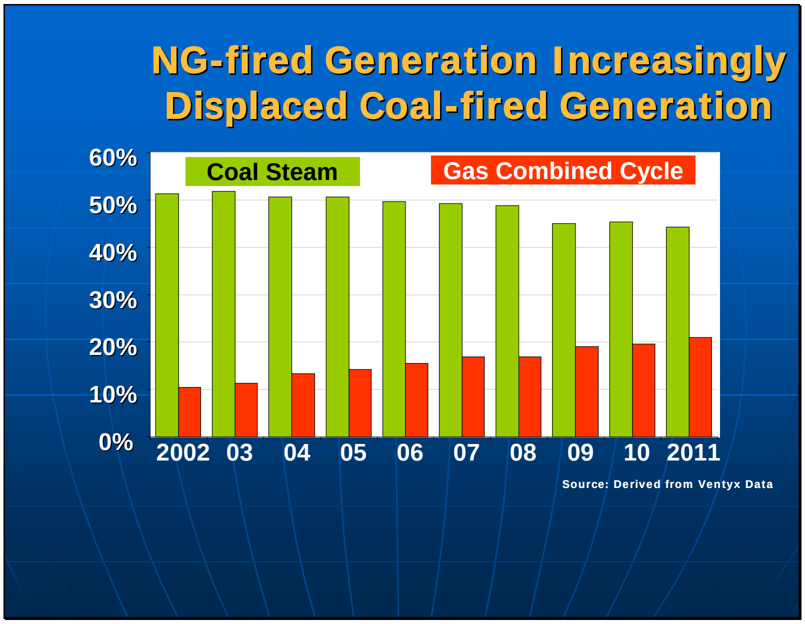


Natural gas-fired combined cycle generation (shown in red on the chart) continues to move up in the nations' supply stack, displacing coal-fired generation (shown in green). Coal generation, as a percentage of total output, declined steadily to 44% in 2011 from about 51% in 2002. Over the same period, generation from natural gas-fired combined cycle plants grew to more than 20% from 10%.

The underlying reasons for increased natural gas-fired generation use are well known: it is cheaper to build, has shorter construction times, and offers more flexible operations with fewer environmental restrictions. Coal plant construction, however, has not come to a halt. Coal still maintains a fuel-cost advantage for large base-load plants in certain locations, particularly where delivered coal costs are low.

This brings us to a more recent situation where decreases in natural gas prices are causing natural gas combined cycle plants to replace some coal plants in the generation supply stack. Some of this transition was starting to take place when natural gas prices were $1 to $1.50/MMBtu higher than they are today. However, there is now additional pressure for natural gas-fired plants to compete with coal production. Low natural gas prices in 2011 helped push the proportion of coal generation down during the year, ending at 39% of total U.S. generation in December.

Over roughly the last decade, the largest volume of natural gas-fired combined cycle generation construction occurred from 2000 to 2005. Their capacity factors have been growing steadily since that time, from the low 30% range to nearly 40%.

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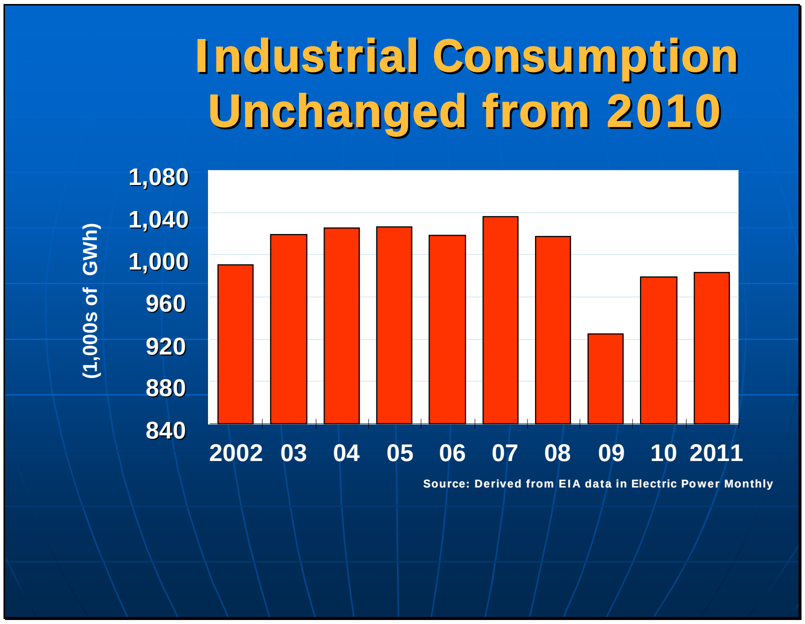


In last year's State of the Markets Report, we told you that the consumption of electricity had partially recovered from a recession-induced decline in 2009. In 2011, this rebound appeared static and overall demand was down by 1%, with little change in each of the three major consumer categories.

This chart shows industrial demand, which was up last year by less than 1% from 2010 levels and mirrors economic activity which rose at a moderate pace, according to the Federal Reserve.

Commercial sales, which are driven by a combination of weather and economic activity, also rose slightly in 2011 from the year before.

Residential sector consumption, which is primarily driven by weather, fell 1.5% in 2011, despite record peak loads in many areas of the country during the summer. Last year's dip in residential electricity sales runs counter to a longer term trend towards more energy-intensive technologies in homes and larger residential structures.

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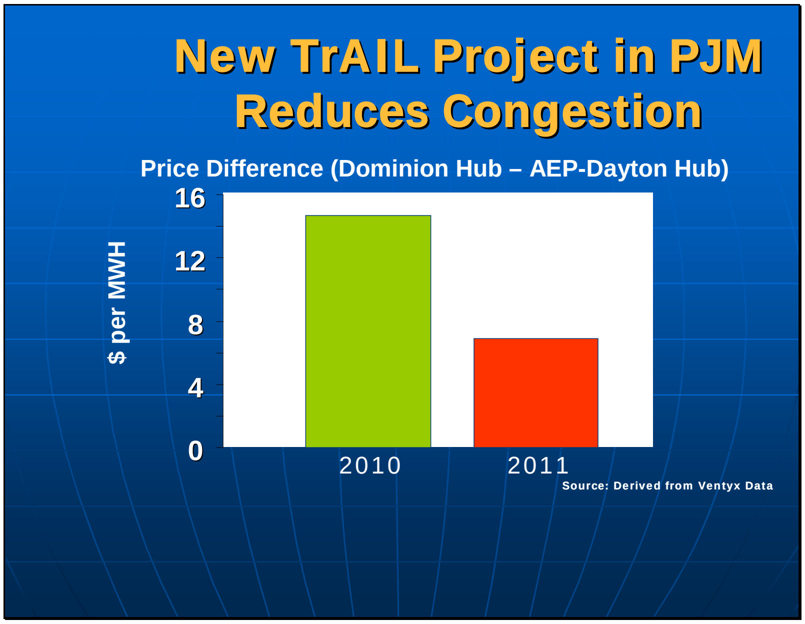


The 218-mile, 500-kV, TrAIL power line in PJM went into service in May 2011. The line begins in southwestern Pennsylvania, crosses northern West Virginia, and terminates in Loudon County, Virginia. It increased west-to-east transfer capability by over 2,600 MW and has helped reduce congestion bringing prices in eastern and western PJM closer together. The graph shows the drop in the price difference between the Dominion Hub and the AEP-Dayton Hub, falling from $14.67/MWh in the summer of 2010 to $6.68/MWh in the summer of 2011.

Over the two interfaces that benefit most from TrAIL, congestion declined sharply and allowed lower cost generation in western PJM to flow to eastern and southern PJM. On the AP South interface, congestion declined by over 1,000 hours while congestion on the Bedington-Black Oak interface declined by over 1,800 hours. Total congestion costs over these two interfaces dropped by half to $262 million in 2011.

TrAIL's benefits were also evident in PJM's forward capacity market. The Reliability Pricing Model, or RPM, provides load serving entities a means of procuring capacity three years in advance of the actual delivery year. This was first seen in the May 2008 auction for the 2011/2012 delivery year, when the line's projected capacity was included in the auction's assumptions for those delivery years. As a result of the line's increased deliverability of capacity, the difference in capacity prices between the east and west regions dropped to zero for the 2011/2012 delivery year from more than $100/MW-day for 2009/2010.

TrAIL has also enhanced system reliability and operational flexibility by making it possible for the RTO to accelerate the re-construction of the 100-mile long Mt. Storm-Doubs 500 kV line, which runs on a roughly parallel path to the TrAIL. TrAIL's new capacity allows operators to take longer outages on Mt. Storm-Doubs during construction and will make it possible to have the line rebuilt by June 2015, about five years earlier than would otherwise happen.

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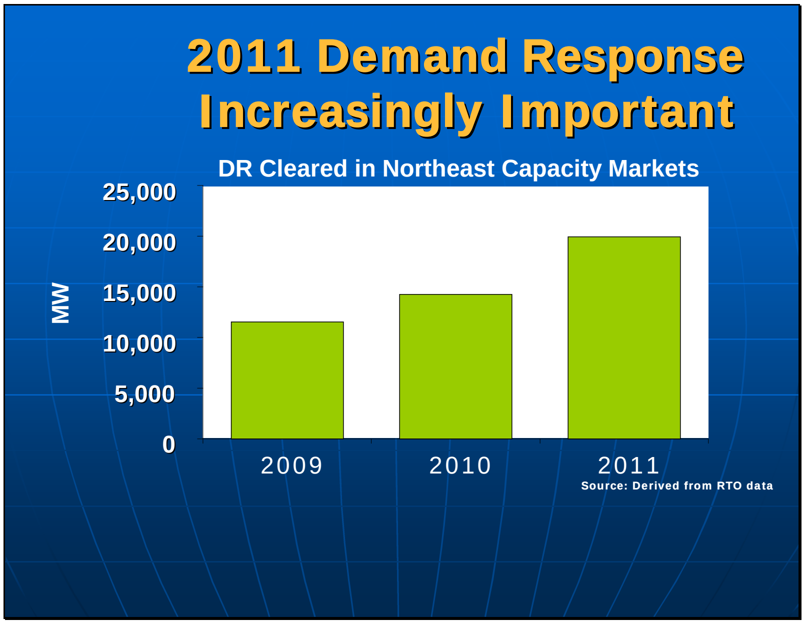


Demand response participation in the RTOs has been increasing and grew by 40% last year in the Northeast to 20 GW of cleared capacity.

In 2011, two notable events demonstrated the important role that demand response plays as capacity that resource operators can call upon to more flexibly balance supply and demand.

On July 22, a heat wave hit the Northeast and Mid-Atlantic, sending temperatures soaring to 104 degrees in New York City and pushing electricity demand to near-record levels. In the most stressed markets – NYISO, PJM and ISO-NE – grid operators invoked emergency measures and called upon real-time demand-response programs that activated 4,800 MW of demand response.

Also, on December 19, ISO-NE experienced a deficiency in operating reserves during the morning ramp and activated 504 MW of demand response. The deficiency was caused by a combination of factors: forced outages, higher than expected load, and unit trips.

During both the July and December events, the programs helped to maintain system reliability and provided operators with alternatives to the most expensive generating units or curtailing service to customers.

Demand response continued to account for substantial capacity in the RTO capacity market auctions held in 2011. In the PJM and ISO-NE forward capacity auctions, which were held for the 2014-2015 delivery period, demand response resources represented 10% of the capacity cleared for PJM and 8% for ISO-NE. In the New York ISO, where its capacity auction was held for the 2011 Summer Capability Period, demand response represented 6% of the cleared statewide capacity.

Providing upwards of 95% of their compensation in PJM and New England, and more than 50% in New York, the capacity markets provided the demand response resources participating in these grid events with significant incentive to enter the market.

In the forward capacity market auctions held in 2011, the PJM and ISO-NE capacity market payments represent between 37 and 60% of the net cost of new generation entry in their regions. In New York, the ISO-provided capacity payments represent approximately 58% of the cost of new generation entry for New York City.

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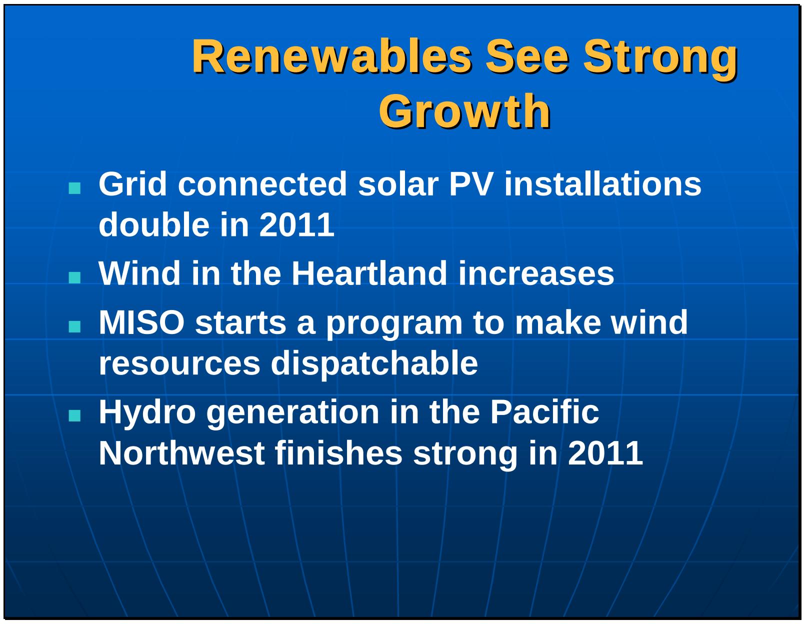


With the Treasury Department's cash-grant program expiring and costs falling, developers rushed to connect photovoltaic solar capacity to the grid last year. There was 1.9 GW in new capacity, or a 109% increase from 2010 levels, led by California and New Jersey. At year-end, total capacity reached 4 GW. In each of the top states, solar investment was encouraged through policies such as solar set-asides in their renewable standards. Additionally, photovoltaic construction costs fell 20% last year, after an 18% drop in 2010.

U.S. wind generation capacity grew by 6.8 GW last year. More than a third of this increase came online in the Midwest ISO (MISO) and SPP. With capacity factors between 30 and 37%, now 1 of every 11 MWh in these regions comes from wind.

As wind generators provide an increasing portion of markets' energy, they need new tools to manage its output more efficiently. On June 1, MISO instituted a voluntary tariff category for variable energy resources, principally wind. By allowing registered resources to be dispatched economically in real-time, "DIR" provides more efficient curtailment through market software to manage congestion, a common need in Minnesota, Iowa and other parts of MISO's western region. Previously, wind resources might be manually curtailed as often as three times daily, with the system instructing wind generators to turn off large blocks of production for long periods of time. By December, 19% of MISO's 10.6 GW of wind had registered as DIR resources.

Hydro generation in the Pacific Northwest finished 27% higher in 2011 than the 5-year average, with roughly 160 TWh generated in 2011. California hydro generation hit roughly 40 TWh, 60% more than the previous 5-year average. As a result, hydroelectric generation displaced natural gas-fired generation in much of the West. For example, California burned 23% less natural gas in their power plants than the 5-year average, while Washington burned 43% less.

This completes our presentation. We would be happy to answer any questions at this time.

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# 2011
# State of the Markets

Item No: A-3

**April 19, 2012**