

Slide 1



Good morning Madam Chairman and Commissioners.

We are pleased to present the Office of Enforcement's 2013 State of the Markets Report. The State of the Markets Report is staff's annual opportunity to share our assessment on natural gas, electric, and other energy markets.

This report does not necessarily reflect the view of the Commission or any Commissioner.



## State of the Markets Highlights

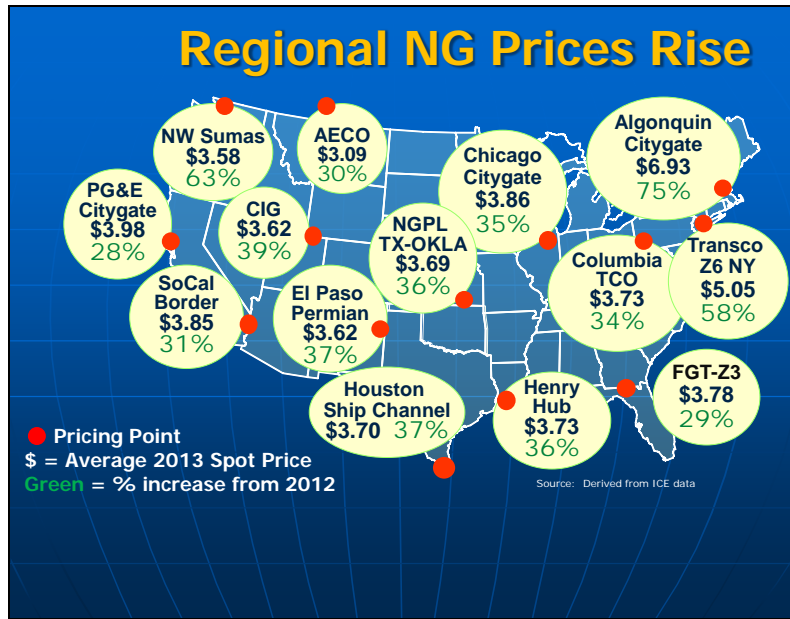
- Spot NG and power prices rise across the U.S.
- Rising NG demand sets new record.
- Shale gas production drives NG supply to record levels.
- RTOs and utilities adjust to changing resource mixes.
- Trading volumes of NG products on ICE fall, while electric trading volumes increase.
- Extreme weather pushes NG and power prices to historic highs in early 2014.

During 2013, natural gas spot prices rose across the U.S, driving production growth from shale gas plays. As a result, total U.S. natural gas supplies reached record levels. Wholesale power prices followed rising natural gas prices. Despite the recent spot price run-up, long-term natural gas futures prices fell in 2013, encouraging long-term demand growth.

A changing generation mix led the electric sector to evaluate and begin making changes to address increased dependence on natural gas and the integration of renewable generation.

Financial trading volumes for natural gas fell on the Intercontinental Exchange (ICE), while financial trading volumes for electricity rose. The rise in financial electric trading is related to a shift from over-the-counter trading to exchange-based trading.

Finally, extreme weather throughout the U.S. in early 2014 stressed natural gas and power markets.



During 2013, most natural gas hubs across the U.S. traded 30 to 40 percent higher than the historically low prices of 2012. Regionally, the highest prices occurred in the Northeast, which occasionally spiked into the \$20 to \$30 per MMBtu range during high demand periods due to pipeline constraints and low liquefied natural gas (LNG) imports.

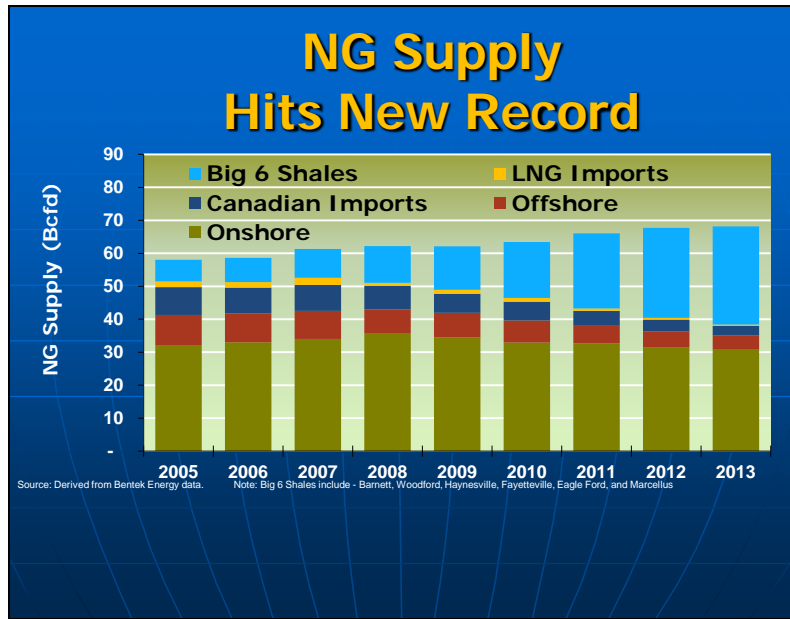
Prices over the rest of the country generally traded within a narrow range, indicating a well-supplied market with few pipeline constraints. The lowest prices in North America occurred at AECO, in Alberta, which occasionally traded below \$2 per MMBtu, as Canadian gas producers lost market share to growing U.S. production. Sub-\$2 prices also occurred in Appalachia, as takeaway infrastructure struggled to keep pace with growing Marcellus gas production.



The recovery in U.S. natural gas prices was demand driven. Overall demand for natural gas increased 2.3 percent in 2013 to 70 Bcfd, the highest on record. Colder than normal weather in the first quarter helped drive residential and commercial demand up 16 percent in 2013.

Industrial sector natural gas demand grew 1.8 percent, supported by new natural gas-intensive industrial projects in mining, manufacturing, and petrochemicals.

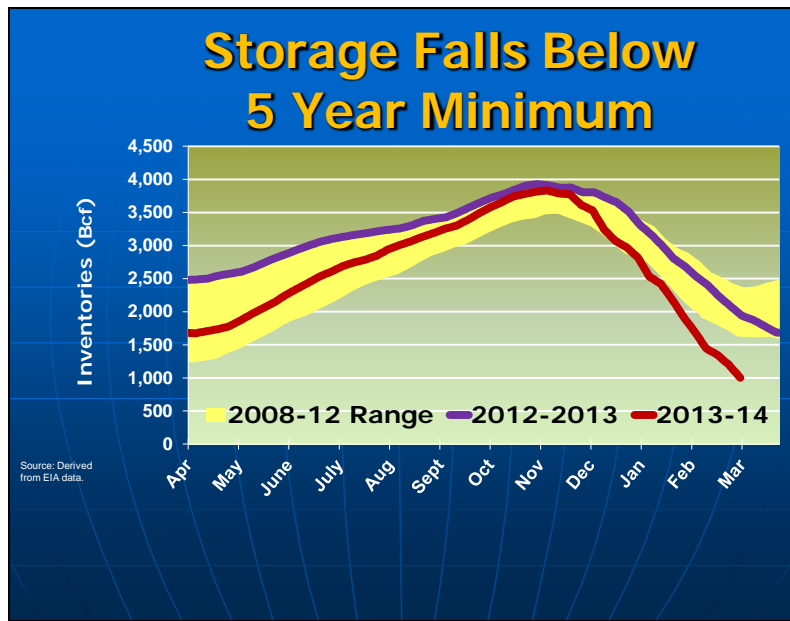
Natural gas demand from the power generation sector declined 10 percent as the increase in natural gas prices reduced natural gas' competitiveness with coal as a generation fuel. Coal use for power generation rose almost 5 percent over 2012.



While demand growth drove natural gas prices up across the country, supply growth helped to moderate some of the price increases. Total U.S. natural gas supply, including production, imports via pipeline, and LNG imports, averaged 68 Bcfd in 2013, up 1.0 percent from 2012.

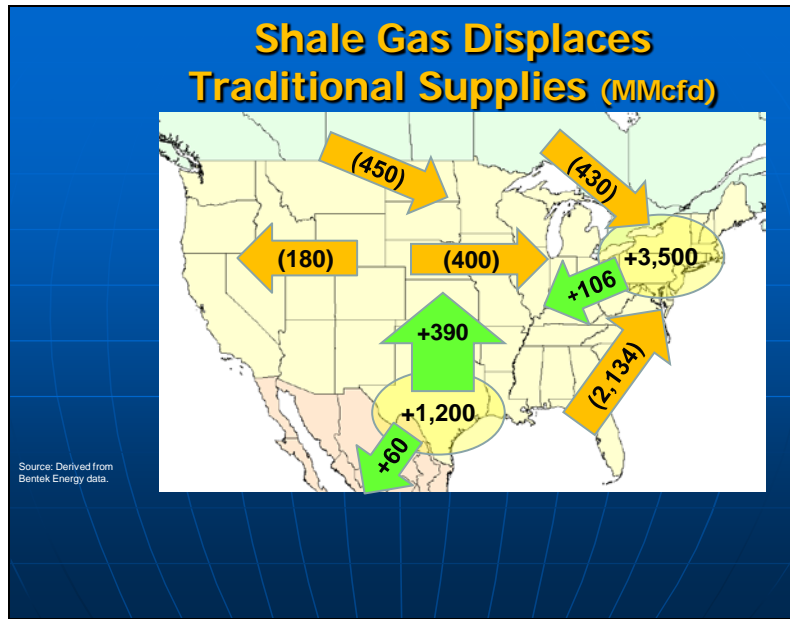
Supported by relatively high prices for natural gas liquids (NGLs) and crude oil, associated natural gas production rose 1.9 percent to 65 Bcfd. The Marcellus and Eagle Ford Shales were the largest contributors to higher production. Production from the Marcellus Shale rose 44 percent to average 12 Bcfd in 2013, while Eagle Ford production rose 36 percent to average 4.5 Bcfd.

Growth in U.S. domestic natural gas production displaced imported natural gas. Net imports from Canada shrank 1.8 percent to 5.2 Bcfd. LNG imports fell to 0.3 Bcfd, a 36 percent decrease from 2012.



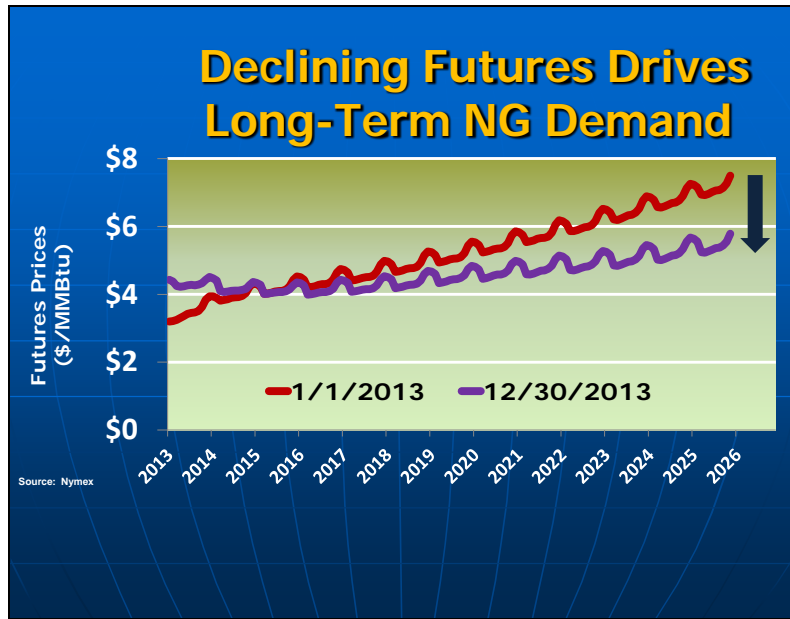
Natural gas in storage was well above the 5-year average for most of the 2012/2013 winter, but late winter cold weather pushed inventories below the 5-year average in the spring. Injections into storage rebounded during late summer and early fall because of mild weather and moderate natural gas demand. By November, storage reached 3,800 Bcf, about 2 percent above the 5-year average.

In contrast to the previous three warmer than normal winters, the winter of 2013/2014 has been much colder than normal, resulting in record storage withdrawals. This has left storage inventories well below the 5-year minimum, and storage could fall to as low as 900 Bcf, a level not seen at the end of winter since 2003.



This map shows natural gas flows and production changes along generalized pipeline corridors from 2012 to 2013. Green arrows represent an increase from 2012 while orange arrows represent a decline from 2012. Circles represent increases at shale gas production areas. Shifts in pipeline flows across the U.S. emerged as natural gas production from shale displaced conventional sources. Marcellus gas located in the Northeast is a closer and often cheaper source of natural gas for major Northeast demand centers. The 3.5 Bcfd increase of Marcellus gas production displaced natural gas supplies from the Southeast, the Mid-Continent, and Canada. Supplies from those regions fell from around 12 Bcfd in 2008 to less than 6 Bcfd in 2013. In some instances, pipelines reversed physical flows to provide Marcellus gas to the Southeast, Canada, and the upper Midwest.

The 1.2 Bcfd increase in Eagle Ford shale production located in the Gulf Coast, led to an increase in pipeline flows to the Midcontinent, which primarily displaced Midcontinent production. This led to sub-\$2 Midcontinent prices during the summer. Growing demand from gas-fired generation in Mexico has also absorbed some Eagle Ford gas production, with year-over-year exports up 8 percent.

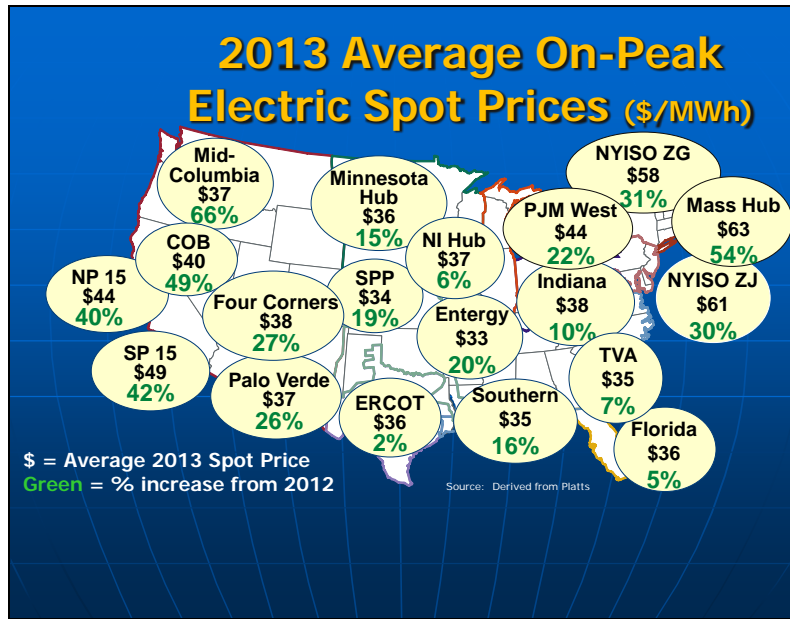


By the end of 2013, growth in U.S. natural gas production had lowered the long-term natural gas futures curve on Nymex. The long-term outlook for low cost natural gas is contributing to investments in natural gas-fired generation and encouraging industrial customers, including petrochemicals and manufacturing, to re-enter the U.S economy. Over 90 new gas-consuming industrial projects or expansions began operations in 2013 and almost 220 new projects or expansions have 2014 in-service dates.

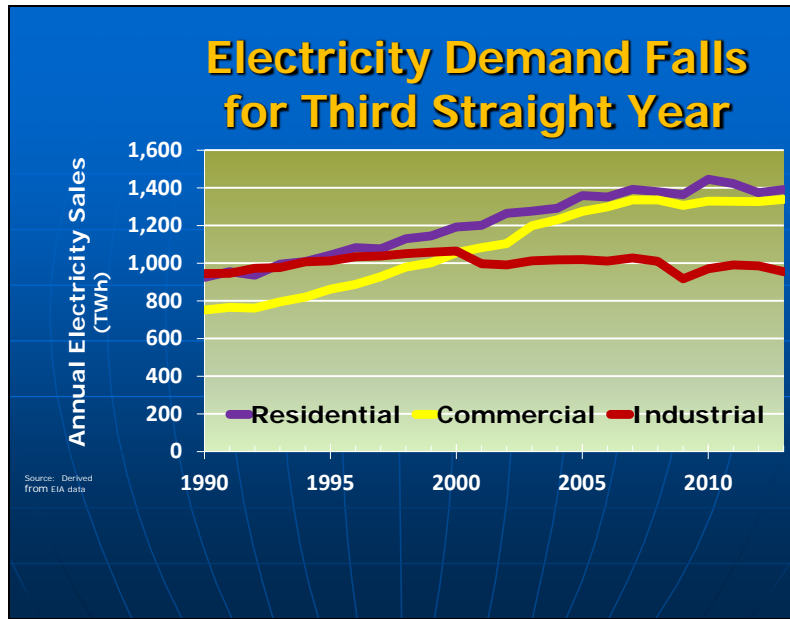
Ample and relatively low cost natural gas is also driving two other potential sources of demand, natural gas exports to Mexico and LNG exports. Proposed pipelines to Mexico total over 4 Bcfd, which would bring total export capacity to Mexico to 9.6 Bcfd in the next few years. LNG exports could also add 6 to 12 Bcfd of natural gas demand by the end of the decade.

All told, these new exports could add as much as 16 Bcfd to overall U.S. natural gas demand by 2020. The decline of the long-term futures curve shows the market expects long-term supply growth to more than meet the growth in long-term demand.

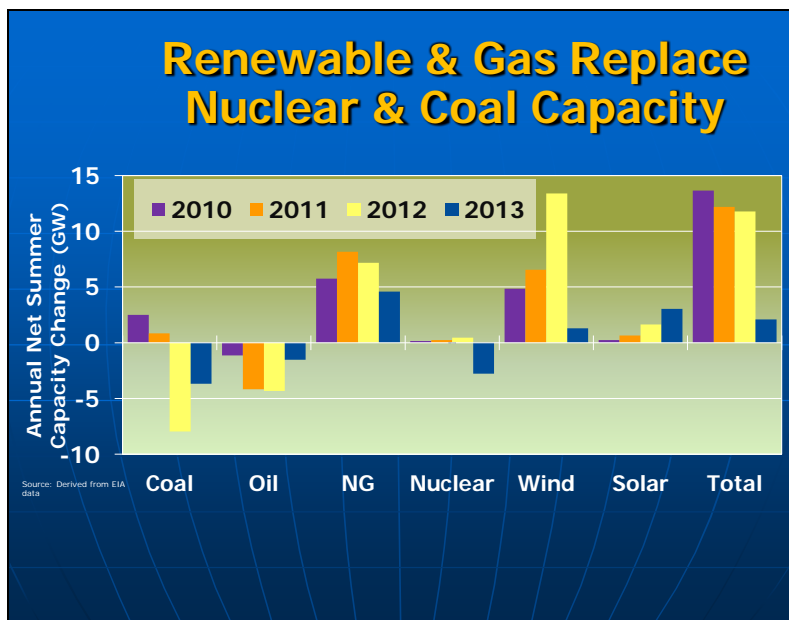




Electricity spot prices rose across the country in 2013, despite a slight decline in demand. Natural gas remained a major driver of electricity prices, with regional prices reflecting, in part, regional variations in natural gas prices. The largest increases were in the Northeast, where prices at the Mass Hub rose 54 percent, and in the West where prices at Mid-Columbia rose 66 percent. Constraints in natural gas supply to the Northeast during periods of extreme weather helped push up prices in the region. Prices in the Northwest and California reflected reductions in hydroelectric generation due to water supply conditions. California's prices also reflected the introduction of Cap and Trade compliance.



Nationally, electricity demand fell for the third consecutive year, dropping by 0.1 percent. Residential and Commercial demand rose slightly despite overall weather conditions being comparable in 2013 and 2012, as differences in winter and summer weather offset each other. Energy efficiency measures and growth in behind-the-meter generation, such as rooftop solar, helped moderate the growth in electricity demand at utilities. The increase in the residential and commercial sectors was offset by the change in industrial demand, which fell 3.1 percent.



Resource additions stemmed not from an increase in demand for electricity but from changing fuel economics and federal and state policies. Markets across the country are adjusting to the changing resource mix, addressing both a growing reliance on natural gas for electric generation and the integration of renewable generation. Total net generating capacity increased approximately 2 GW in 2013.

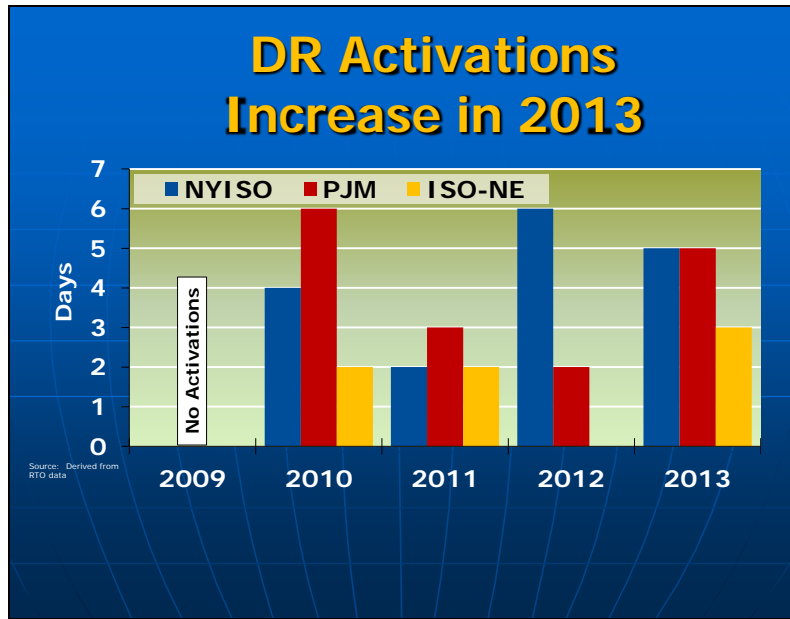
Natural gas-fired generation capacity posted the largest net increase, almost 5 GW, and continues to constitute the largest share of electric capacity. Greater use of natural gas for generation increased the sensitivity of the electric sector to natural gas prices and supply issues. For example, New England has experienced price volatility, transportation disruptions, and greater use of oil-fired generation during extreme weather events, while California has seen strained natural gas supplies during region-wide cold spells.

Retirements of aging nuclear and coal plants reached almost 3 and 4 GW, respectively. Some RTOs have looked to interim measures to keep generators running until transmission or generation alternatives can be developed.

Utility-scale solar resource additions were up over 3 GW and set a new record. Wind generation additions, while down from 2012, added more than 1 GW of nameplate capacity.

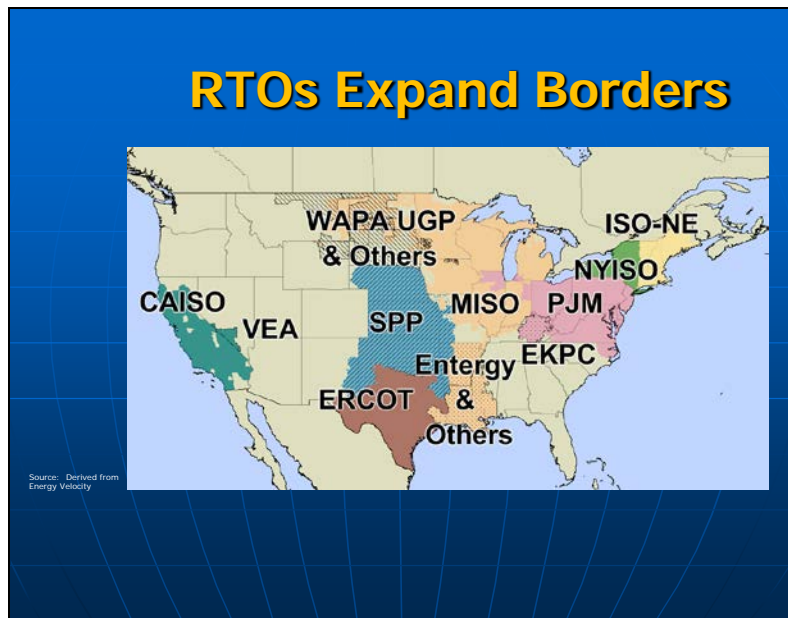
Markets across the country are evaluating and taking steps to address their changing resource mix, particularly growing use of natural gas and renewable resources. Examples include New England, where the ISO developed a winter reliability program to bolster fuel oil inventories at power plants, and California, where the ISO proposed market changes to encourage renewables to respond to price signals and ensure that sufficient ramp capability is available.



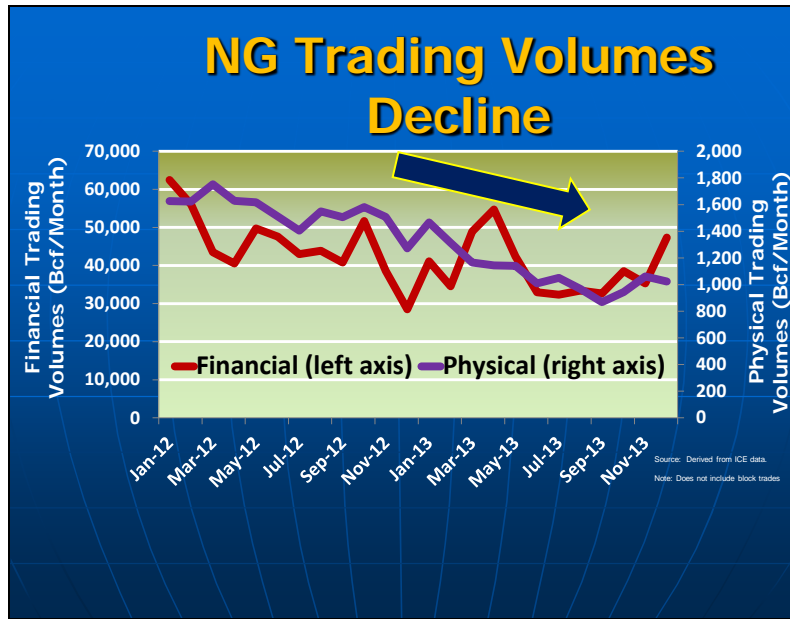


Northeast RTOs called upon their emergency demand response programs for a combined total of 13 days in 2013, more than in any of the last five years, underscoring the resource value of demand response during periods of tight supply conditions.

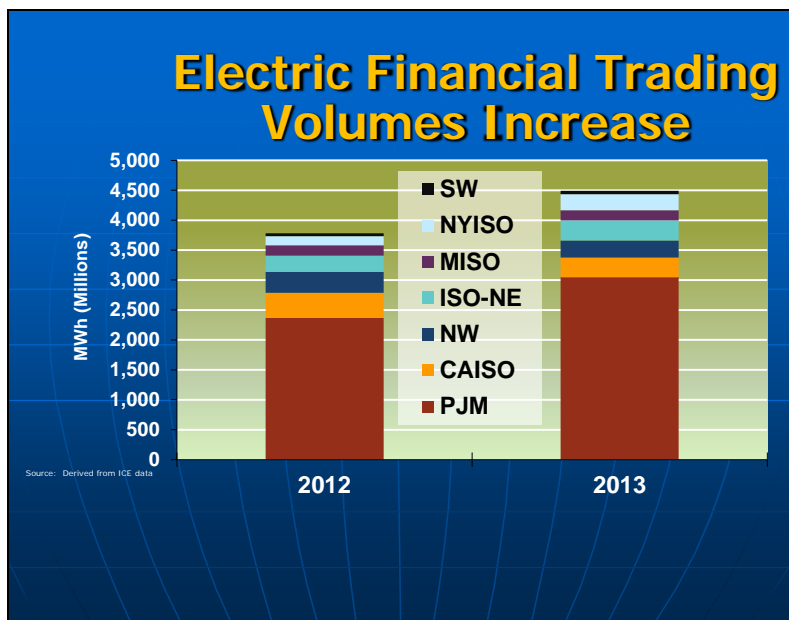
The amount of demand response offered and cleared fell in RTO auctions held in 2013 for capacity to be delivered in upcoming periods, reversing a multi-year trend. In PJM and ISO-NE, cleared demand response capacity fell by approximately 2,400 MW and 900 MW in their respective markets. In NYISO, rule changes implemented to improve the accuracy and responsiveness of demand response resources were followed by 550 MW less eligible demand response resources clearing the New York capacity auction.



Market participants continue to see value from Regional Transmission Organizations. In 2013, MISO expanded to the Gulf of Mexico as Entergy, Cleco Corporation and other utilities joined its market. Entergy expects its customers to see benefits of \$1.4 billion over the first decade, while MISO estimated that other Midwest region members will see a similar benefit. The East Kentucky Power Cooperative became part of PJM and CAISO expanded outside California when Nevada's Valley Electric Association joined the ISO.



Natural gas financial and physical trading volumes declined in 2013, with financial volumes on ICE falling 14 percent, similar to the decline of financial products on the Chicago Mercantile Exchange. Physical trading volumes on ICE dropped 30 percent. Financial volumes continue to significantly outweigh physical volumes, and were 36 times larger in 2013. The decline in traded volumes coincided with falling trader profitability due to relatively stable natural gas prices in 2013.



Reported electric financial trading volumes on ICE rose 19 percent from 2012 to 2013, led by longer-term transactions. Trades with duration between two months and one year increased 44 percent overall.

In October 2012, ICE converted cleared energy swaps to futures to address regulatory requirements raised by the Dodd-Frank Act. One of the goals of the Dodd-Frank Act is to facilitate increased transparency in the markets. The 2013 increase in trading volume reflects this improved transparency as transactions previously conducted bilaterally are now cleared on exchanges such as ICE.

During 2013, 92 percent of the financial trading of U.S. electricity products outside ERCOT took place at an RTO hub, up from 90 percent in 2012. Most regions in the country experienced increased financial trading volumes compared with 2012. PJM's financial products continue to be the most traded on ICE, with 68 percent of the total financial trades involving a PJM product, up from 63 percent of 2012.



## **Extreme Weather Stressed Natural Gas and Electricity Markets in 2014**

- Record cold temperatures during January resulted in record gas demand, well freeze-offs, large storage withdrawals, and constrained pipelines.
- In the mid-Atlantic and Northeast, spot natural gas prices soared to over \$120 per MMBtu.
- On-peak power prices spiked to over \$1,000 per MWh.
- Staff monitored the winter events as they occurred and continues to assess what happened in the markets and whether market manipulation potentially took place.

In recent years, natural gas and electricity markets have benefitted from growing natural gas supply and mild weather. The winter of 2014 illustrates how extreme weather can still stress natural gas and electricity markets.

In January 2014, U.S natural gas demand set a new daily record of 137 Bcfd. Well freeze-offs, record storage withdrawals, and high pipeline utilization led spot natural gas prices at the Henry Hub to jump to a January high of \$5.70 per MMBtu. In the mid-Atlantic and Northeast, spot natural gas prices soared to over \$120 per MMBtu at key trading points. RTO on-peak prices spiked to greater than \$800 per MWh in Boston and Chicago and greater than \$1,000 per MWh in Eastern PJM. Some non-firm customers faced challenges in obtaining natural gas and others were voluntarily curtailed. Although markets were stressed, there were no widespread natural gas or power outages because of a lack of fuel supply. The Commission recently announced that it will hold a technical conference on April 1 to explore the impacts of recent cold weather events on the Regional Transmission Organizations and Independent System Operators, and discuss actions taken to respond to those impacts.

The Office of Enforcement's market oversight and surveillance functions routinely monitor both wholesale natural gas and electric markets and their results. Staff monitored this winter's extreme weather events as they unfolded and is looking closely at the developments surrounding them. Enforcement staff followed up on screen trips from its algorithmic surveillance screens with data requests and phone interviews with numerous market participants, including generators, gas suppliers, and ISO staff to determine if market manipulation potentially took place. To date, staff has not uncovered any activity it believes to be manipulative. However, staff's work in this regard is ongoing and OE will report to the Commission when its inquiries are completed.



This concludes staff's prepared comments. A copy of this presentation will be posted on the Commission's website. We are available to answer any questions you may have.