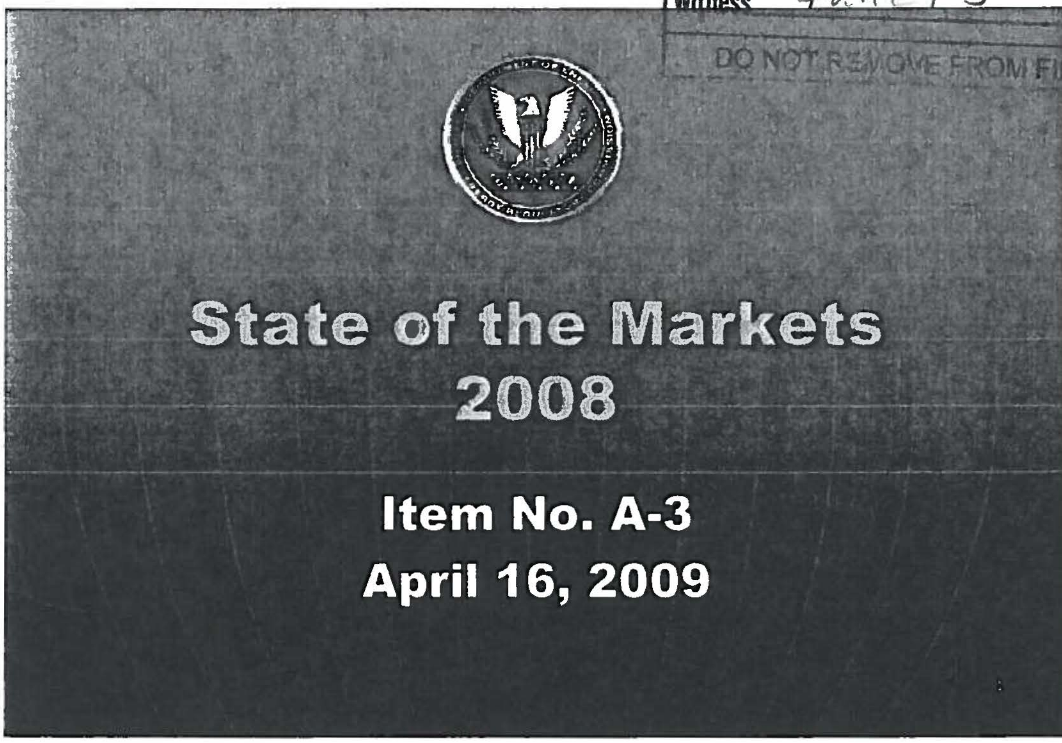
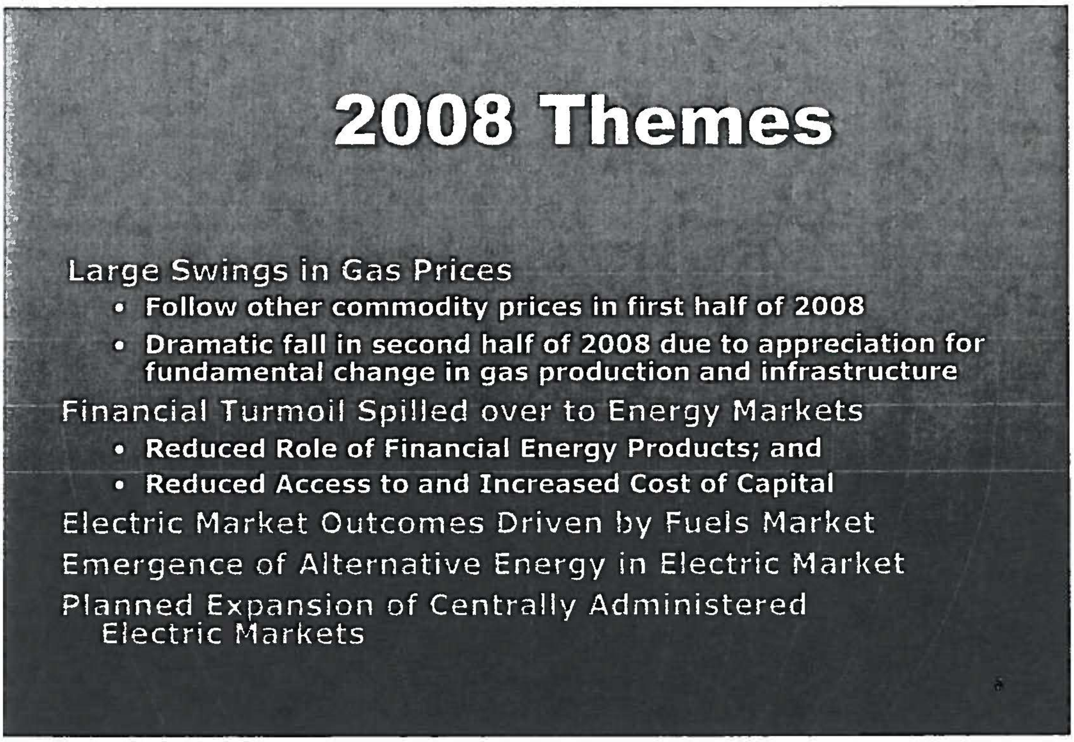


Mr. Chairman, Commissioners. Today I'm pleased to present the Office of Enforcement's 2008 State of the Markets Report. This powerpoint presentation will be posted on the oversight section of the FERC website following this presentation. We will post the full report in the near future.

I am here with Steve Reich, Deputy Director of the Division of Energy Market Oversight, Chris Peterson, chief of the Division of Energy Market Oversight's Fuels Market Analysis branch, and Keith Collins, chief of the Division of Energy Market Oversight's Electric Market Analysis branch.

The State of the Markets is staff's annual opportunity to share observations about natural gas and electric market performance during the previous year.



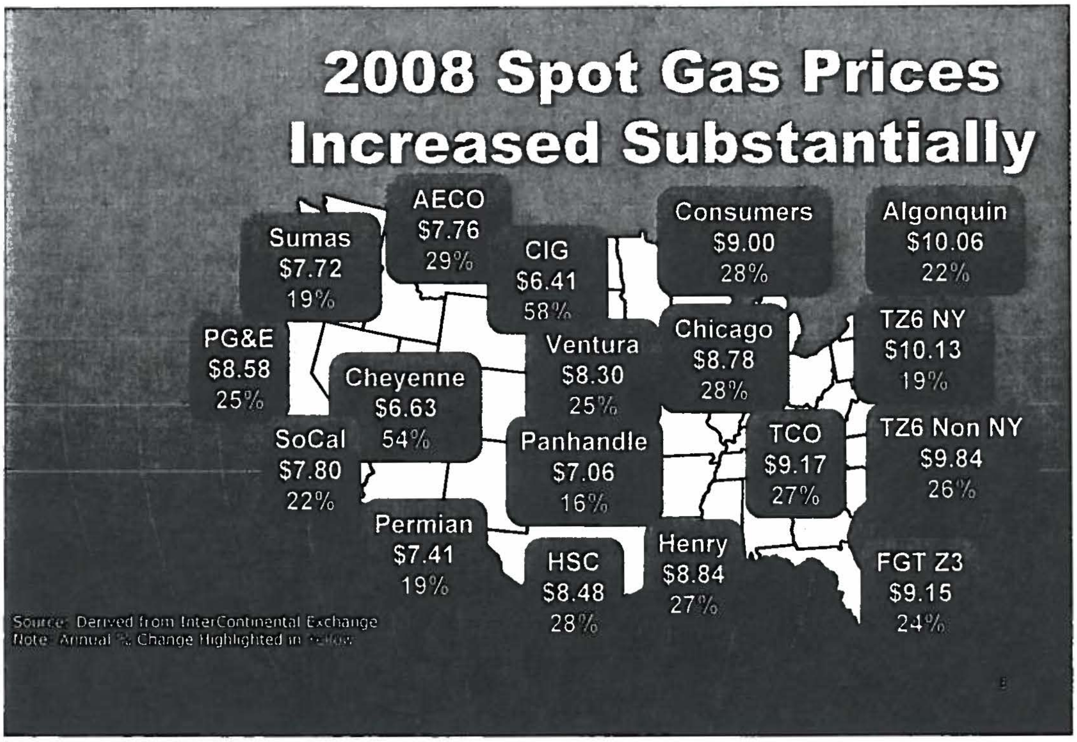
Today we will touch on a number of overarching themes. We will start by discussing the market forces that drove natural gas prices during 2008, a period of dramatic fluctuation and unprecedented summer prices. We will first describe why we believe physical fundamentals alone can not explain natural gas prices experienced during the first half of the year. We will then discuss how trends in unconventional gas production and new infrastructure, which started several years ago, are fundamentally altering the nature of natural gas markets.

Second, we will describe how the financial crisis that hit the country during the second half of the year altered the role of financial products and players in energy markets and increased the cost of capital while simultaneously reducing the access to capital.

We will then discuss the key drivers of electricity market outcomes. With the exception of the emergence of alternative energy sources, most electric market outcomes were driven by outside forces – specifically, fuel and commodity prices and the financial crisis. We will describe how alternative energy options, including energy efficiency, demand response and wind generation have emerged as key components of electricity markets. We will then note several initiatives to broaden the scope of centrally administered electric markets, including in regions that have depended solely on bilateral trading.

Finally, we will note early results from the Commission's efforts to enhance release of natural gas transportation service and reassignment of electric transmission service.

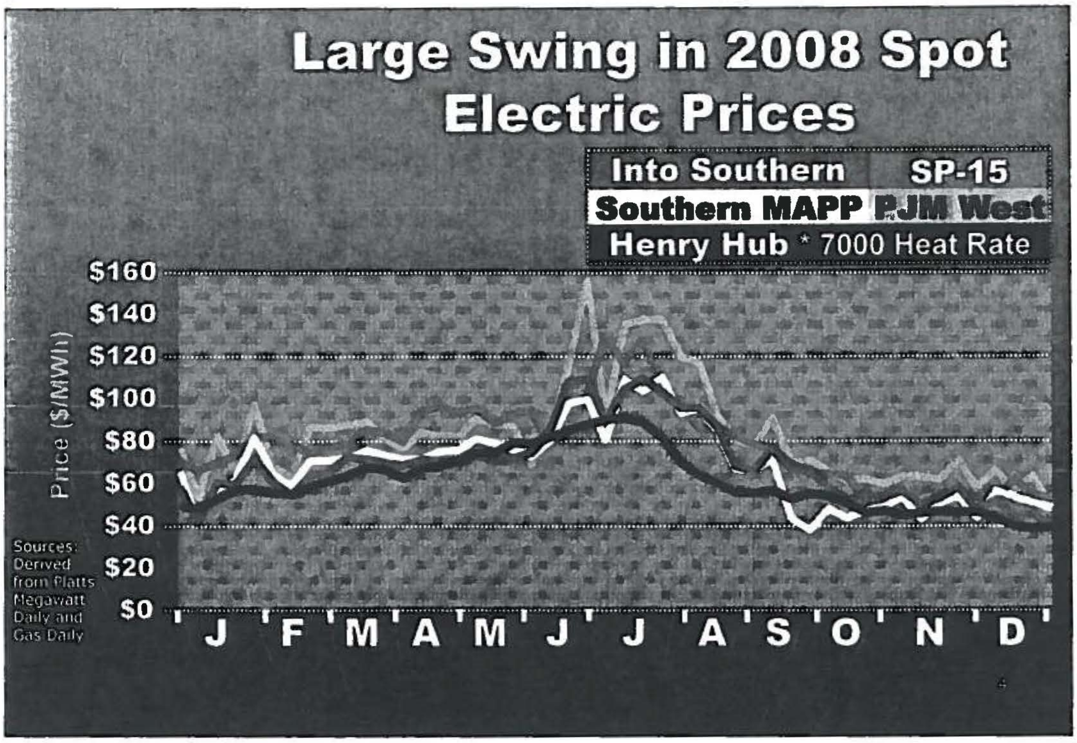
Before discussing these themes, I will provide a brief summary of natural gas and electricity price outcomes during 2008.



Average electricity and natural gas prices in 2008 were substantially greater than prices in 2007 in virtually every region of the United States.

With a few exceptions, average natural gas prices were between 16% and 29% greater than during 2007. The exceptions were largely the result of infrastructure added during the course of the year. For instance, average natural gas prices at Cheyenne were 54% higher than 2007 due to increased pipeline infrastructure out of the Rockies that allowed gas frequently bottled up in 2007 to flow to higher priced markets. This had a cascading effect on other regions. Rockies gas that flowed to the Midwest displaced traditional mid-continent supplies that flow southwest into Southern California. This new flow pattern created a divide between Northern and Southern California prices as Southern California began receiving mid-continent gas. Rockies gas flows into the Midwest also replaced higher cost Canadian gas imports, which were down 12.5% in 2008 compared to 2007.

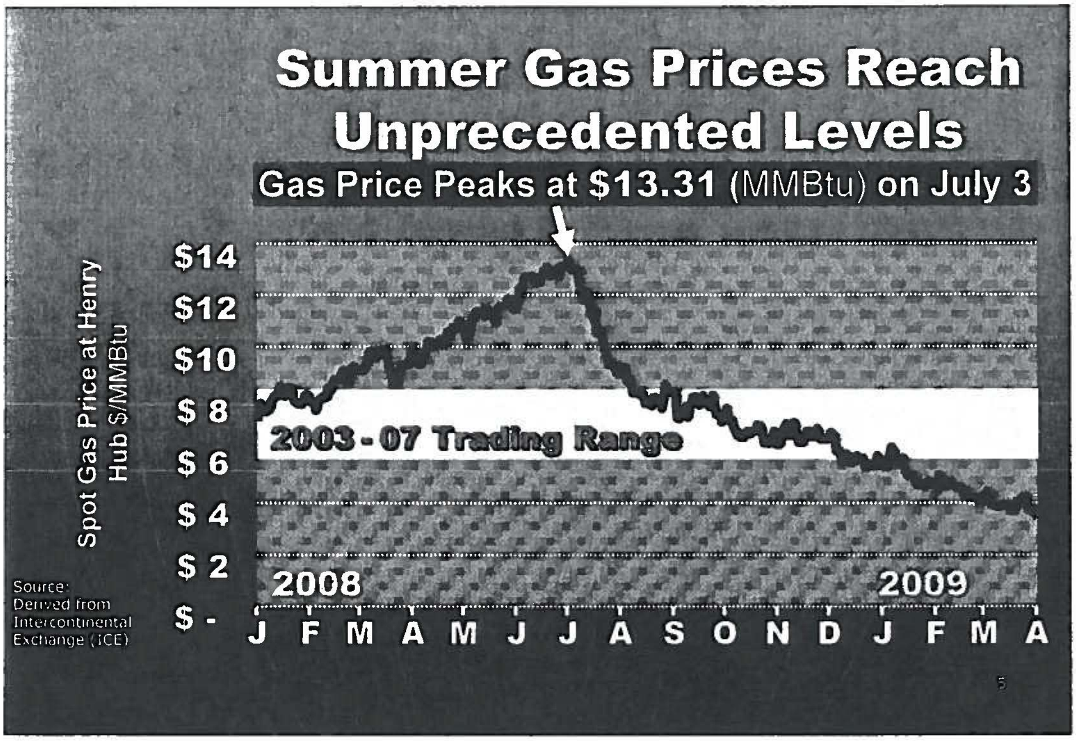
Driven by the increase in natural gas and coal prices, average electricity prices were between 12% and 21% greater than during 2007.



However, focusing on average prices masks the incredible swing in prices experienced during the course of the year. In fact, prices at the end of 2008 were lower than prices at the beginning of 2008. This graph depicts average weekly spot prices at major electricity pricing hubs compared with the fuel cost of a hypothetical 7000 heat rate gas plant based on the Henry Hub spot natural gas price. The graph illustrates that the dramatic swing in electricity prices was driven by equally dramatic swings in fuel prices, principally natural gas, oil and coal prices.

Although not displayed on this graph, I would note that central Appalachian coal futures prices rose dramatically from $55/ton at the start of the year to $117/ton in mid-October, and then fell back to $62/ton by the end of the year. Other coal prices experienced similar fluctuations.

I will now discuss the physical and financial drivers of natural gas prices during 2008.



Natural gas prices increased during the summer of 2008 to levels never before experienced during any previous summer in the United States. Henry Hub prices peaked at $13.31/MMBtu on July 3. By the end of the year, Henry Hub spot prices had fallen to $5.71.

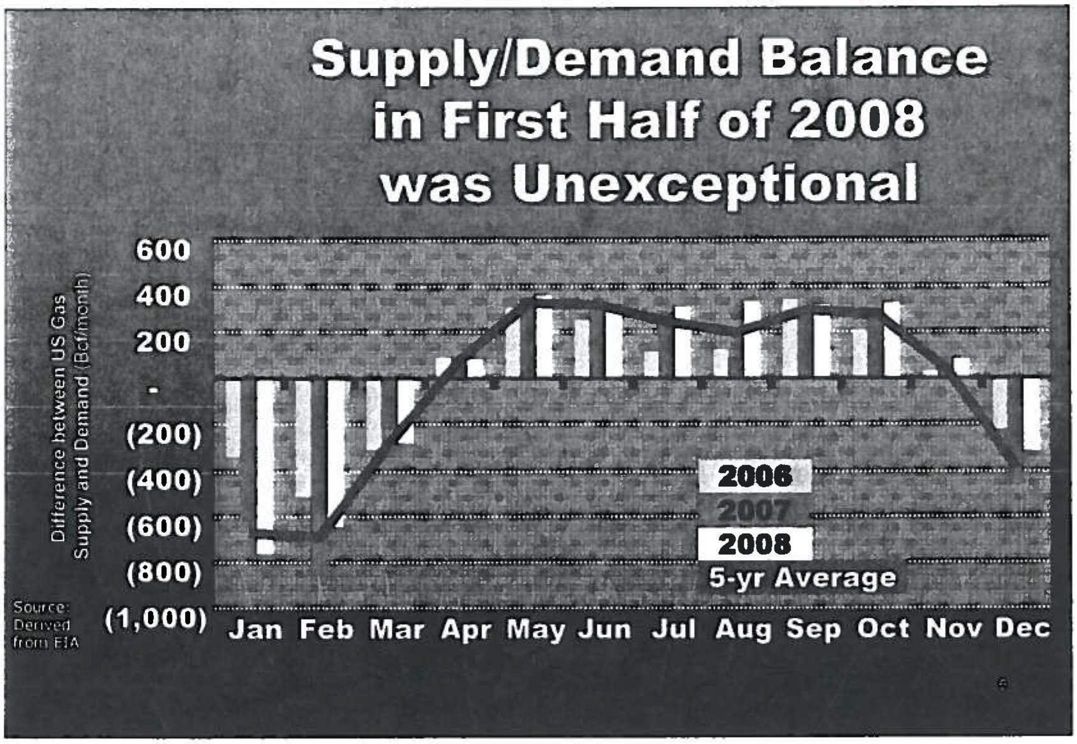
Our review of the physical fundamentals during the first half of 2008 suggests that supply and demand factors alone can not explain this dramatic swing in prices. Nonetheless, there were a number of discrete issues that put upward pressure on prices:

- •A cold January led to the highest gas demand in 10 years and the largest withdrawal from storage in 11 years.
- •Net gas imports from Canada were down 14% during the first half of 2008, while LNG imports were off 64%.
- •The offshore Independence Hub had to shut down repeatedly during April and May, losing up to 900 MMcfd, or about 46 Bcf for the entire period.
- •A hot June led to a surge in gas consumption from power generators to meet air conditioning load.

Similarly, a number of discrete issues contributed to lower prices in the second half of 2008:

- •A relatively cool July and August helped moderate demand from power generators.
- •The financial crisis contributed to declining gas demand, particularly for the industrial sector in the final quarter of 2008.
- •Gas storage recovered to levels above the 5-year average

All of these discrete issues ultimately have to have acted through the overall market balance, which we address more closely in the following slides.



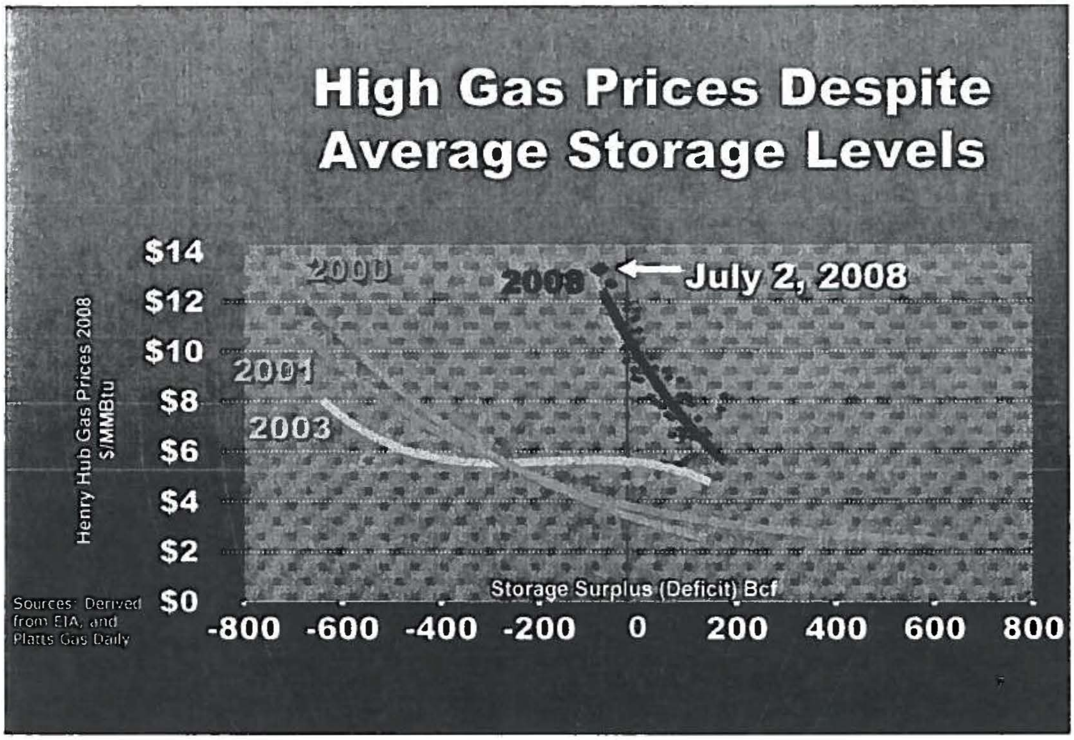
Overall, the supply/demand balance in 2008 was unexceptional. We'll address supply and demand dynamics during the first half of 2008 separately to start, before turning to combined effect of these dynamics.

Notwithstanding the discrete issues identified, there were no major disruptions to supply during the first half of 2008 that would explain the increase in prices. Total gas supply, including domestic production, pipeline imports and LNG imports, was up 3% through June of 2008 relative to the same time period in 2007. In September, hurricanes Gustav and Ike did cause a considerable drop in supply availability - more than 10 Bcf/d. This drop, however, occurred after gas prices began their precipitous late-summer decline, briefly interrupting but not ending the prices' downward trajectory.

Gas use through June 2008 increased 3.6% relative to 2007, primarily because gas demand in January and March was higher than 2006 and 2007.

Supply and demand do not work in isolation. Rather, the overall balance of supply and demand dictates the relative tightness of the natural gas market. As this graph illustrates, the supply/demand balance through June 2008 was not significantly more bullish than the 5-year average balance, except in January. Importantly, there was not an exceptional surplus of gas supply in July when prices started to fall dramatically, though the August surplus was large.

Therefore, with the exception of January and August, the overall supply/demand balance was unexceptional.



An alternative measure of natural gas market tightness is the amount of gas in storage. To a large extent, this measure should track the supply/demand balance, as a supply imbalance is met by withdrawing gas from storage.

As winter 2008 progressed, storage levels fell steadily relative to the 5-year average, reaching the 5-year average by the end of March. The United States had not experienced storage levels at or below the 5-year average in the recent past. Thus is possible that relatively low storage affected market perceptions and thus explains some of the increase in prices during the first three months of 2008.

However, the level of price increase was unprecedented relative to recent experience, as illustrated by this graph. This graph is a scatter plot covering recent periods of storage at or below the 5-year average. The horizontal-axis shows the storage surplus defined as the difference between EIA's weekly storage estimate and the 5-year average level. The Y-axis shows the average weekly spot gas price at the Henry Hub. The points are color coded to correspond to the year when they occurred, with a trend line for the year in question showing the general relationship between prices and relative storage levels. The general shape of these curves shows that below normal storage levels coincide with higher prices and above normal storage levels coincide with lower prices. However, the shape of the curve for 2008 is much steeper than during prior periods. That is, in previous years extremely high prices corresponded to periods of much larger storage deficits.

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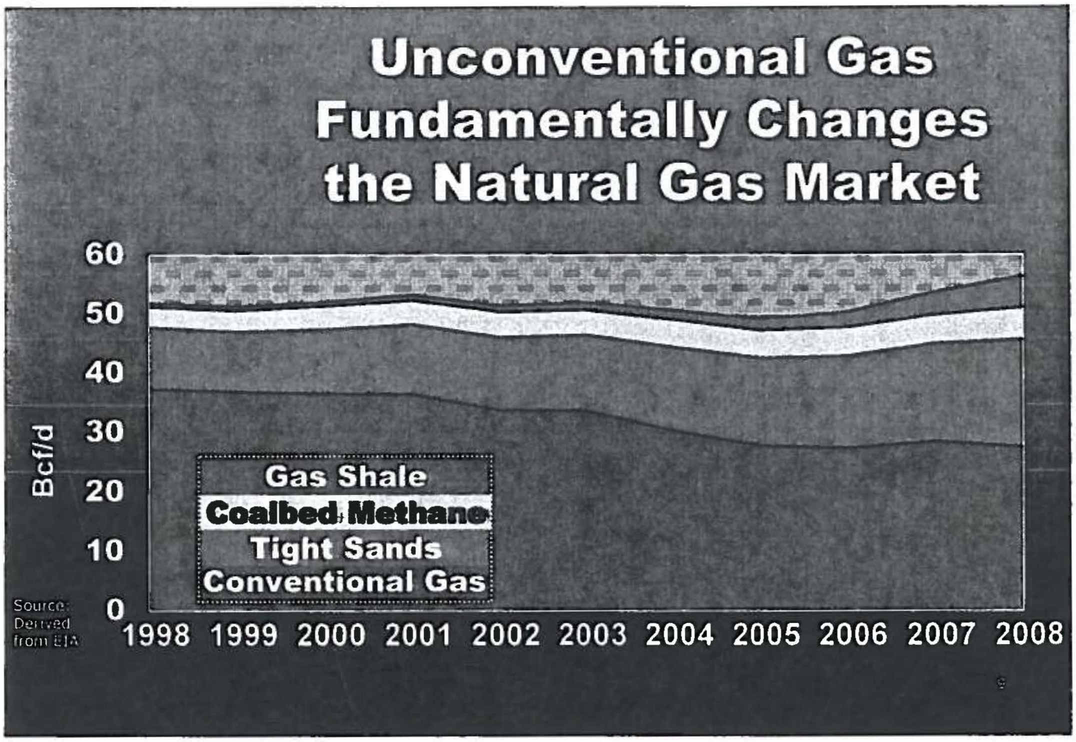
In addition, much of the period of relatively low storage levels occurred in the spring and early summer, when those injecting gas have the maximum flexibility in their storage choices. As a result, the steep price increase likely *caused* the low inventories. In addition, storage levels remained at relative low-levels throughout July and mid-August, though storage was climbing back to the 5-year average, as natural gas prices fell dramatically, which suggests that any adverse market perceptions related to low storage levels dissipated quickly.

In summary, while physical market fundamentals, particularly storage levels, can explain why natural gas prices rose during the first six months of 2008, none of the market fundamentals were extreme enough to explain why spot Henry Hub prices reached $13.31/MMBtu by July 3.

As we discussed at the Winter Assessment last fall, the rise in natural gas prices coincided with a global increase in many commodity prices. This increase in commodity prices occurred as large pools of capital flowed into various financial instruments that essentially turn commodities like natural gas into investment vehicles. Ultimately, we believe that financial fundamentals along with the modest tightening in the supply and demand balance for gas during the first part of 2008 explains natural gas prices during the year.

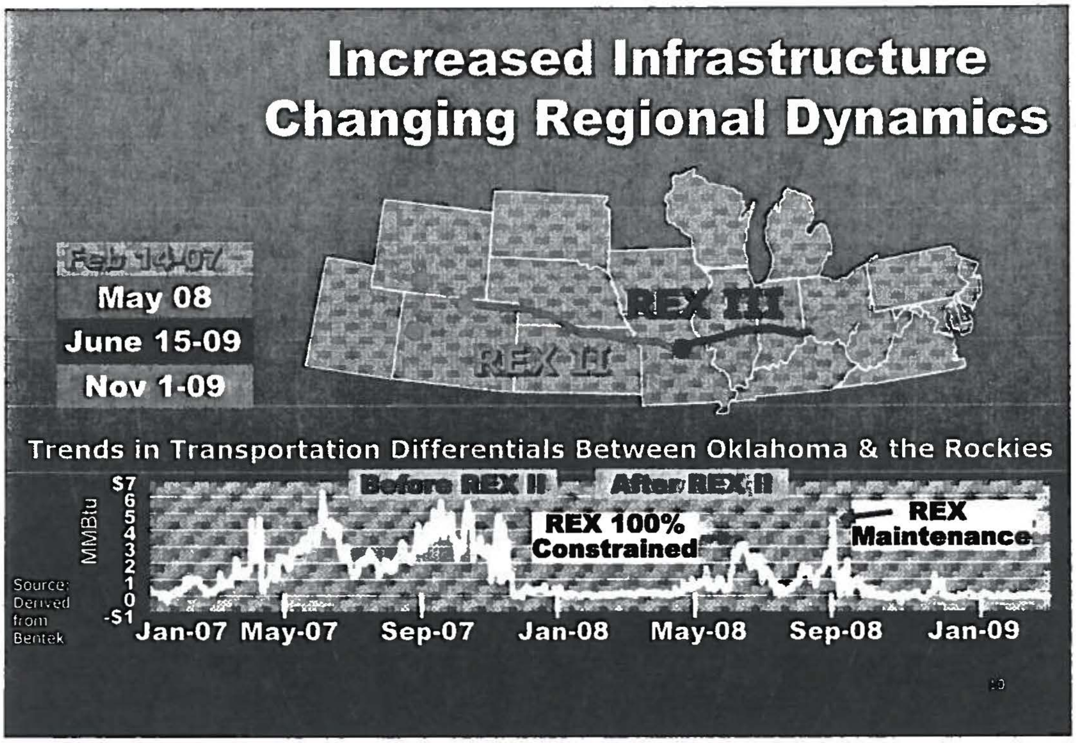


Today natural gas prices are below $4/MMBtu. The physical factors that drove prices in Q4 2008 and Q1 2009 have the potential to fundamentally change the natural gas markets over the next few years. In short, natural gas is not scarce. Going forward, a key consideration is whether the natural gas production will be able to get into balance with consumption in a manner that will not lead to an exaggerated boom-bust cycle.

Natural gas production growth has been concentrated in what has been traditionally referred to as unconventional gas fields. These fields include tight sands, coal-bed methane and shale formations, some of which are located near traditional producing basins, while others are located in remote areas. In 2008, unconventional gas production represented 51% of total natural gas production and grew 14% in 2008, while conventional production declined 3% in 2008.

These unconventional gas plays have become economic due to innovations in horizontal drilling and fracturing technology. Unfortunately, there is limited information available on prices needed to cover operating and capital costs, including a reasonable return on investment; and the available estimates are disparate. On the low end break-even prices range from $3.30/MMBtu to $5/MMBtu. On the high end, break even price estimates for most producing basins are in the range from $5/MMBtu to $7/MMBtu range.

Given the plausible range of break-even prices, prices at the end of Q1 2009 are somewhat below the price needed to sustain drilling activity in most unconventional basins. This is borne out by the dramatic plunge in the gas rig count during the fourth quarter of 2008, from a peak of over 1,600 in early September to less than 900 currently. If sustained, the slowdown in drilling will likely lead to much lower production growth or even production declines, which could in turn lead to much higher prices when industrial gas demand rebounds.

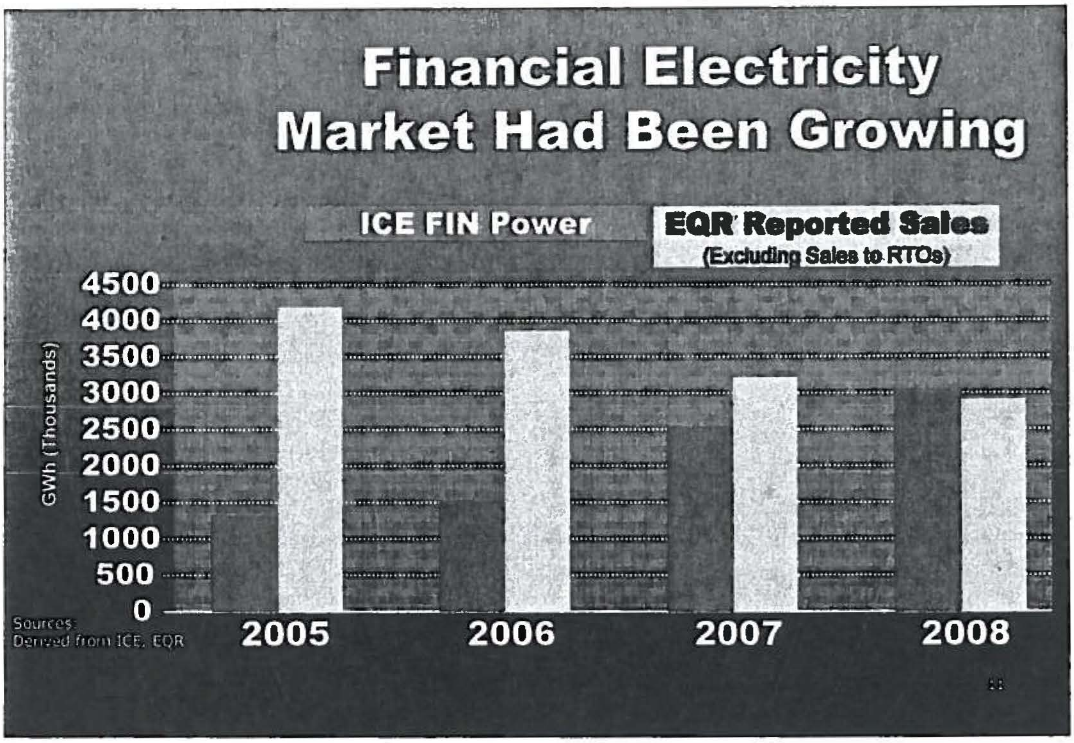


A key issue is whether the natural gas market will be able to move available low cost supply to consumption centers. By the end of 2009, new production and infrastructure is poised to transform the natural gas markets in the major consuming regions. Chief among these projects is the Rockies Express project. On January 9, 2008 Kinder Morgan finished Phase II West of the Rockies Express Pipeline which transports 1.5 Bcf/d of natural gas from major production fields in Colorado and Wyoming into central Missouri. REX II West interconnects with several major Midwestern pipelines, allowing Midwest shippers access to lower priced Rockies gas. The first phase of REX III is scheduled to be in-service by June 15, with some interim service to central Indiana available by mid-May.

After the commencement of REX II West, transportation price differentials between the Rockies and the midcontinent declined, as the new pipeline linked the two regions and allowed the prices to track more closely. As illustrated in this graph, in 2008 the average physical price differential between the mid-continent region and the Rockies declined by 68% ($1.39/Mmbtu) from the previous year. As REX II reached capacity during the summer of 2008, the chart notes a corresponding increase in the price differential indicative of the constraint to transport cheaper Rockies gas further east.

Overall, pipeline capacity has been added to better integrate robust unconventional natural gas production into the national pipeline grid. EIA estimates that intrastate and interstate natural gas pipeline developments added an unprecedented 45 billion cubic feet per day (Bcfd) of new capacity, three times more capacity than the previous year. Also noteworthy is the magnitude of the pipeline projects, with many designed to transport over 500 million cubic feet per day (Mmcfd).

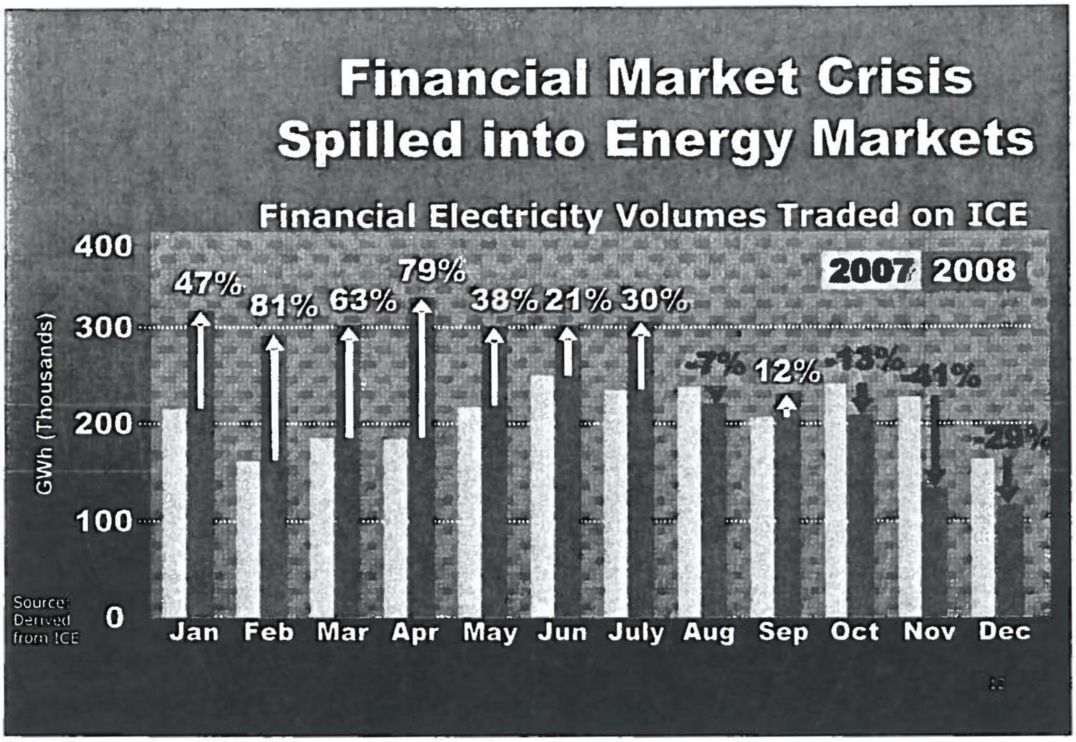
Finally, potential liquefied natural gas imports are another potential short- and medium-term driver. During 2008, the United States received less than 1 Bcfd of LNG as prices in the rest of the LNG-importing world were higher than US prices, Asian and European demand was high, and there were occasional supply shortfalls. However, world LNG prices have fallen substantially since the end of 2008, to the point that northeast prices for natural gas were on par with the rest of the world by the end of March 2009. In addition, additional LNG supplies are coming on-line and Asian and European demand has fallen off. Some analysts foresee US imports greater that 3 Bcfd by the third quarter of 2009. A large inflow of LNG could put substantial downward pressure on natural gas prices, especially if US demand does not rebound or production growth does not slow.



We'll now describe how the financial crisis seems to have spilled over into energy markets. We'll start by describing the evolving role of financial energy products over the last few years. We'll then describe how financial energy trading changed after the financial crisis started. Finally, we'll discuss the longer-term implications of the financial crisis on energy market participants.

During 2008, financial products continued to play a growing role in energy markets. As this graph depicts, In the electricity markets, financial contracts continue to play in increasingly prominent role. Starting with the third quarter of 2006, financial trading on IntercontinentalExchange (ICE) has increased relative to the previous year every quarter until the fourth quarter of 2008. At the same time, physical sales of electricity, as report in the Electric Quarterly Report, have fallen every quarter relative to the previous year since Q4 2004, with the exception of Q1 2008. We have categorized EQR sellers into three broad categories – utility, independent power producer, and financial institutions/marketer – based on the company that files the EQR. Based on this determination, we can see that much of the drop in physical market activity is the result of fewer sales by the financial institutions/marketers category. This is particularly true in California, the Pacific Northwest, ISO-NE and PJM.

Similarly, as we have documented previously, the volume of financial natural gas trading dwarfs physical natural gas trading. NYMEX and ICE futures trading, which is for a term of one month, is several orders of magnitude greater than monthly physical deals.

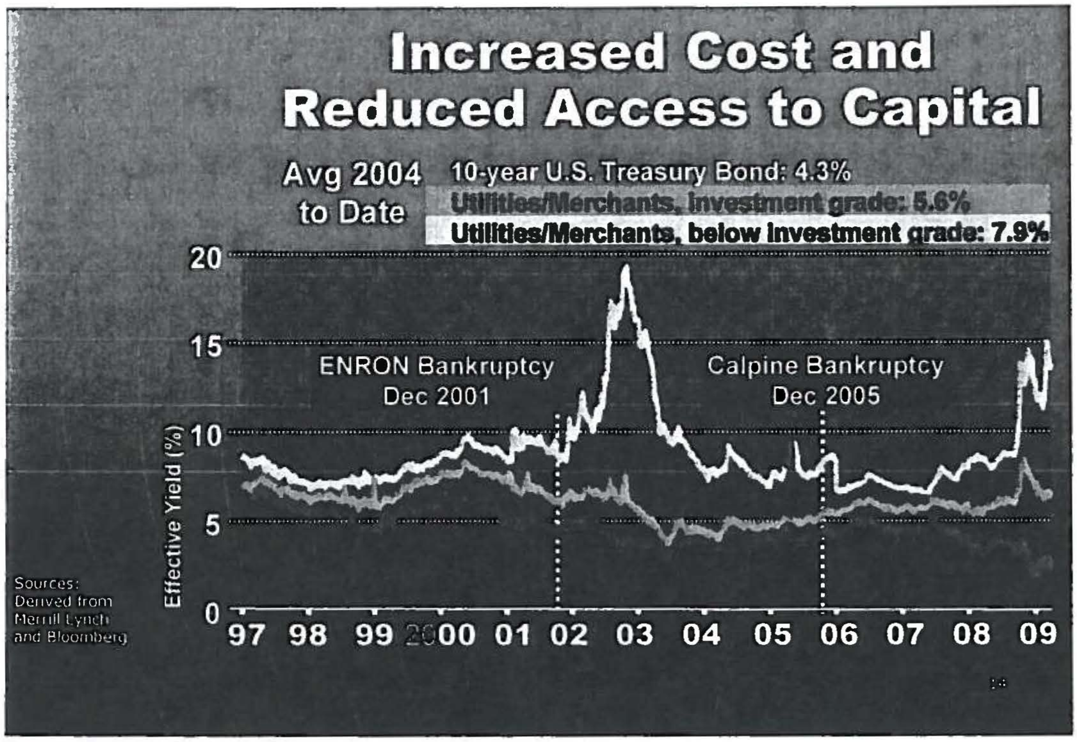


As volatile as natural gas and electricity prices were during the first half of 2008, the capital markets were equally volatile during the second half of 2008. As financial institutions experienced growing distress, the energy markets were affected in two ways. First, trading of financial energy products decreased, while financial institutions and energy marketers took a smaller role in energy markets. Second, energy market participants experienced reduced access to and a higher cost of capital, resulting in reductions in capital expenditure budgets.

As this chart illustrates, by August 2008, the volume of financial electricity product trading on ICE started to drop relative to the previous year. This occurred after dramatic increases from January through July. This pattern held in most of the largest volume trading hubs. For instance, in the largest ICE trading hub, PJM West, Q4 2008 trading was down 39% relative to Q4 2007. Trading at both SP-15, the second largest hub, and NEPOOL, the fourth largest hub, was down just over 10% after earlier gains. The volume of Q4 2008 trading at several other hubs, like Mid-Columbia, the third largest hub, and Cinergy, was flat relative to Q4 2007, even though trading during the first part of 2008 was up substantially relative to 2007.

Despite the fact that the volume of financial trading has fallen, we note that additional financial electricity products continue to be developed. For instance, the Nodal Exchange - an electronic platform that facilitates trades of a number financial electricity products, including something that is similar to financial transmission rights - began operation this month.

Similarly, this graph depicts the fact that financial natural gas trading on ICE also declined in the last two months of 2008. It is important to note that physical volumes are graphed on the right axis in order to illustrate this point. The volume of financial trading continued to be an order of magnitude larger than physical trading. For the first 10 months, the volume of trading across all US natural gas products traded on ICE was roughly 34 times larger than physical trading. By December, that ratio fell to about 22.

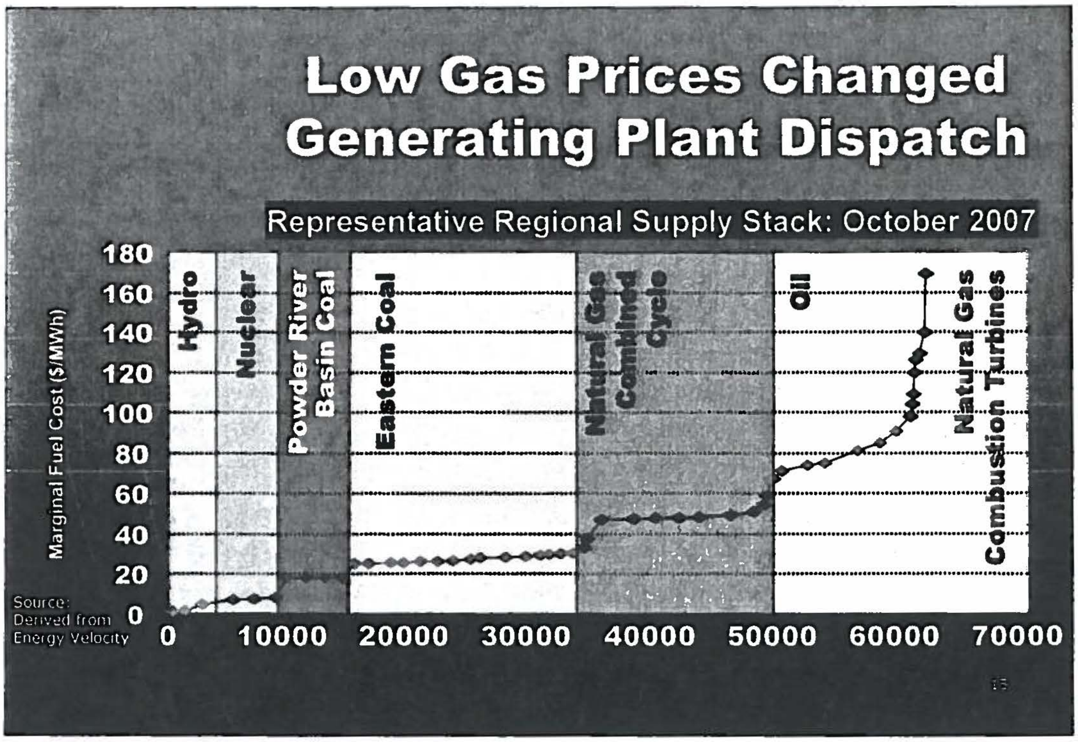


The financial crisis affected energy market participants in several ways. First, the financial crisis limited the availability of credit. During the Commission's January 2009 credit conference, a number of panelists noted that companies with lower credit ratings have not been able to access commercial paper and other short-term credit markets, with the availability and cost of credit from banks have been even more severely impacted due to their financial troubles.

As this graph of debt yields for electric and gas utilities depicts, for those utilities that have been able to access the credit markets, the cost of credit has increased. The increase has been most dramatic for non-investment grade utilities. As a predictable result of the reduced access to capital and increased cost of capital, a number of energy market participants have indicated the intent to reduce capital expenditures in 2009.

Oversight staff have been tracking announcements by natural gas producers of their intentions to reduce capital expenditures in 2009 and beyond. Based on a sample of the larger companies that have made such announcements, we have identified more than 20 producers who announced during the latter part of 2008 the intention to reduce capital expenditures by more than $22 billion. Some of the planned reductions are almost certainly related to the fall in natural gas prices and the desire to rebalance supply and demand. Nonetheless, some of these announcements are also likely related to reduced access to capital and the increased cost of capital.

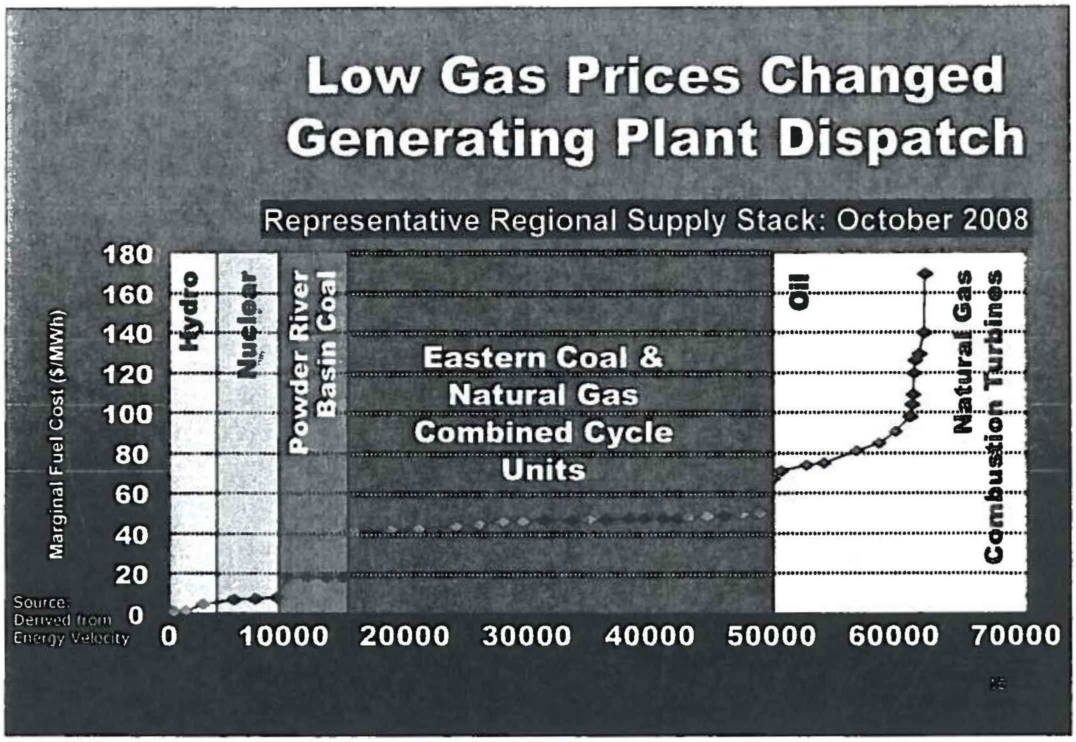
On the electric side, a recent report by the Edison Electric Institute, indicates that capital expenditure budgets have been reduced by about 10% for 2009 and 2010. Oversight staff's survey of cancelled generation projects indicates that the capacity of cancelled projects in the first quarter of 2009 is almost as large as the capacity of projects cancelled in all of 2008.



Electricity market outcomes in 2008 – including spot prices, fuel on the margin, and the construction of new electric generation – were driven largely by market forces outside the electricity market. With the exception of the maturation of alternative energy, the electricity market was like a boat on the ocean – pushed up and down by external forces.

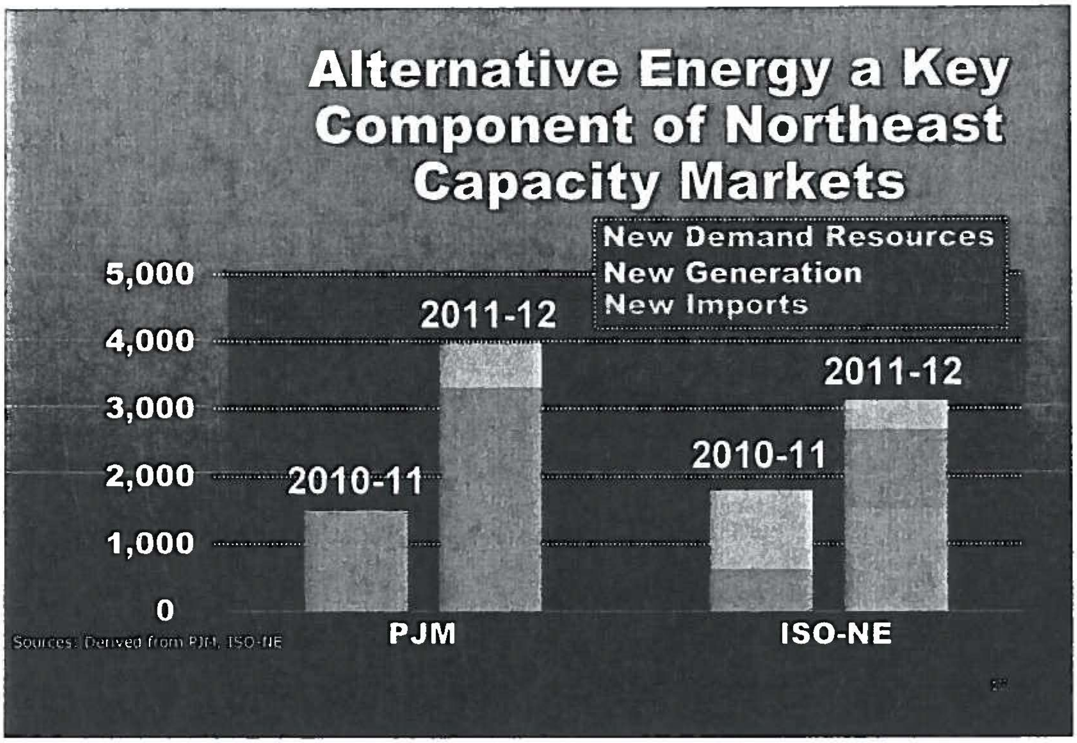
As I mentioned at the start of the presentation, spot electricity prices during 2008 were driven largely by the underlying fuel costs, with typical reactions to extreme weather events like the late spring run-off in the Pacific Northwest that drove down Mid-Columbia prices.

As fuel costs changed over the course of the year, the merit order of the electric supply stack changed as well. This graphic shows that, during the first half of 2008, mildly efficient coal-fired generating plants, using coal from essentially any source, enjoyed an operating cost advantage over natural-gas fired generation.



As this graphic illustrates, as natural gas prices started falling in July and coal prices stayed high, natural gas fired generation became competitive with plants that use eastern coal. In some regions, particularly the Southeast and the mid-Atlantic, natural-gas fired generation became competitive with any coal plant that did not use Powder River Basin coal.

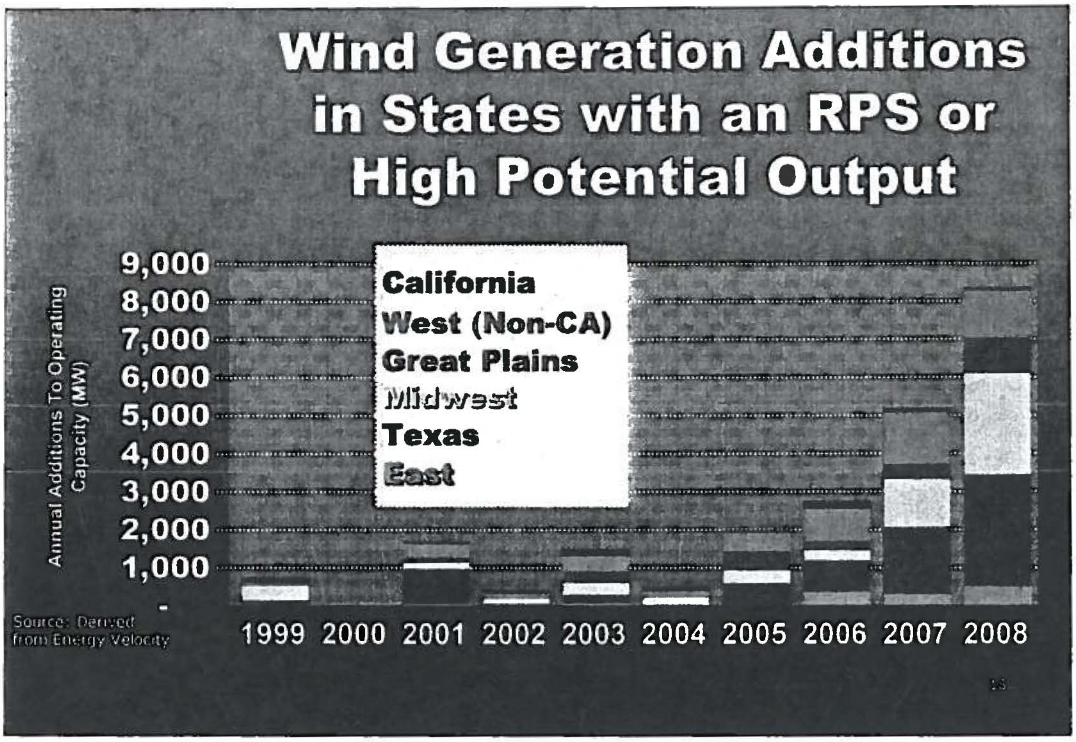
This has the potential to effect operations, as coal fired plants typically have a minimum operating level that is a small fraction of their maximum output, while combined-cycle gas plants have a minimum operating level that is half of their maximum output. To the extent that combined cycles become baseload plants, the availability of capability to ramp up in the morning and down in the evening may be reduced.



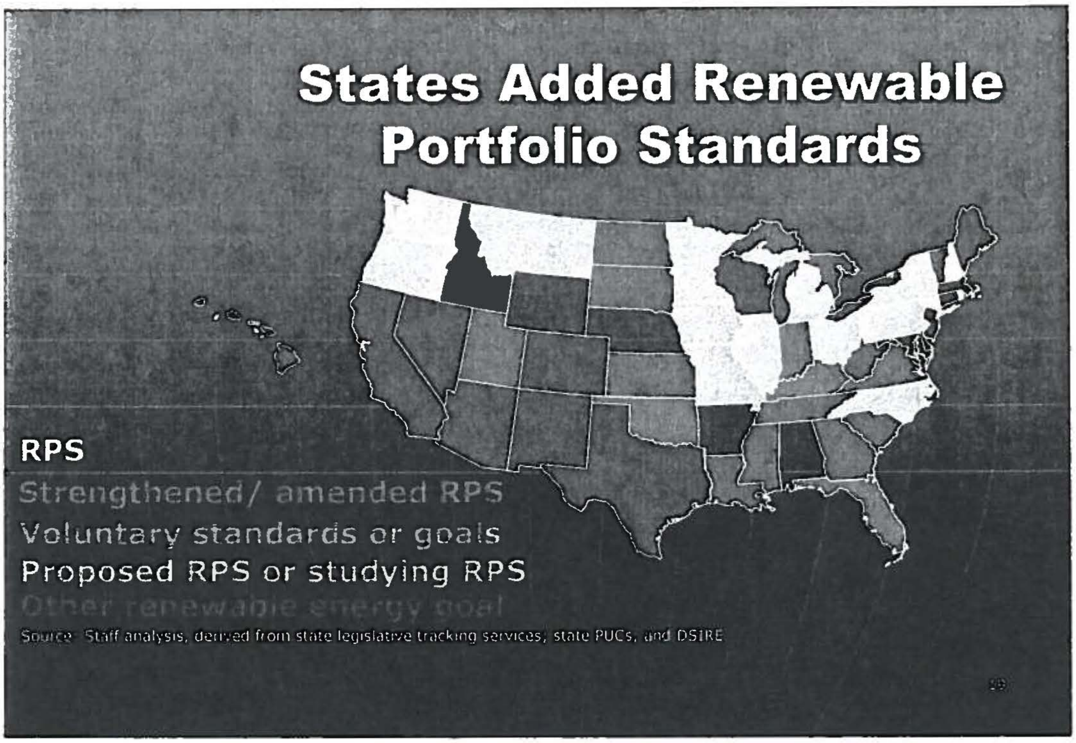
Nationwide, during 2008, electric generating capacity was added at the rate experienced since 2005, which is substantially below the rate of additions from 2001 through 2003. The moderate additions in new capacity is likely due in part to the fact that many regions of the country enjoy healthy reserve margins.

In addition, the moderate growth in new capacity is also likely due to the fact that increases in construction costs and fuel prices led to increases in the cost of new generation during the year, as we discussed at our June 2008 presentation to the Commission on the Cost of New Generation. The cost of constructing a new power plant increased almost 10% during the first three quarters of 2008, driven by increased costs for specialized labor as well as key inputs like steel and cement. While underlying input costs dropped substantially in the fourth quarter, the measure of construction costs maintained by Cambridge Energy Research Associates (CERA) held steady. CERA attributes the absence of downward pressure on construction costs to the fact that equipment manufacturers and construction companies continued to have a backlog of orders. Our conversations with market participants validates CERA's conclusion. In addition, during the last quarter of the year financing costs increased substantially and access to capital dried up, as discussed earlier.

Turning to the Northeast, while generation additions were modest, at least relative to 2001 through 2003, energy efficiency and demand response programs emerged as a viable option for addressing future load growth. As this graph depicts, ISO-NE cleared 838 MW of new demand response resources and 798 MW of new energy efficiency resources in its two forward 2008 capacity auctions. Similarly, PJM cleared 29 MW of new demand response in its first forward auction in 2008, and 662 MW of new demand response in its 2nd auction.



The generation capacity that was added in 2008 was dominated by wind and gas-fired units This is likely driven both by uncertainty related to carbon policy and regulatory policies, including state renewable portfolio standards and the federal production tax credit, that facilitate the development of wind generation. Overall, 8,376 MW of wind capacity was added in 2008, with over half of that total coming from Texas and Iowa, and more than 75% coming from just seven states. The top seven states have either high wind potential or a renewable portfolio standard or both.



This map depicts all states with either a renewable portfolio standard requirement or a voluntary goal. During 2008, three states passed a new RPS, five jurisdictions amended or strengthened existing standards, four states with an existing goal strengthened them, and four states adopted a voluntary RPS or renewable goal

Overall, 17 states include energy efficiency in their RPS or renewable goals, and at least three other states include energy efficiency in an integrated resource plan or other mandate. Several states issued major energy plans or draft plans with goals encompassing renewable energy, energy efficiency, and greenhouse gas reduction, including California, Kentucky, Nebraska, New Jersey, New York, and Vermont.

Finally, we will note that the Commission took a number of actions to enhance the ability of demand response resources to provide ancillary services. In its 2008 State of the Markets report, PJM's market monitoring Monitoring Analytics note that "throughout 2008, the MW contribution of demand-side response resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices." Monitoring Analytics went on to say that, during 2008, demand side resources accounted for all cleared Tier 2 synchronized reserves in 27 percent of hours when a synchronized reserve market was cleared. In the hours when all supply was from demand-side response resources, the unweighted average price was \$2.58, while the unweighted average synchronized reserve price for all cleared hours was \$8.49.

A key development to monitor in the coming year is the expansion of centrally administered wholesale energy markets.

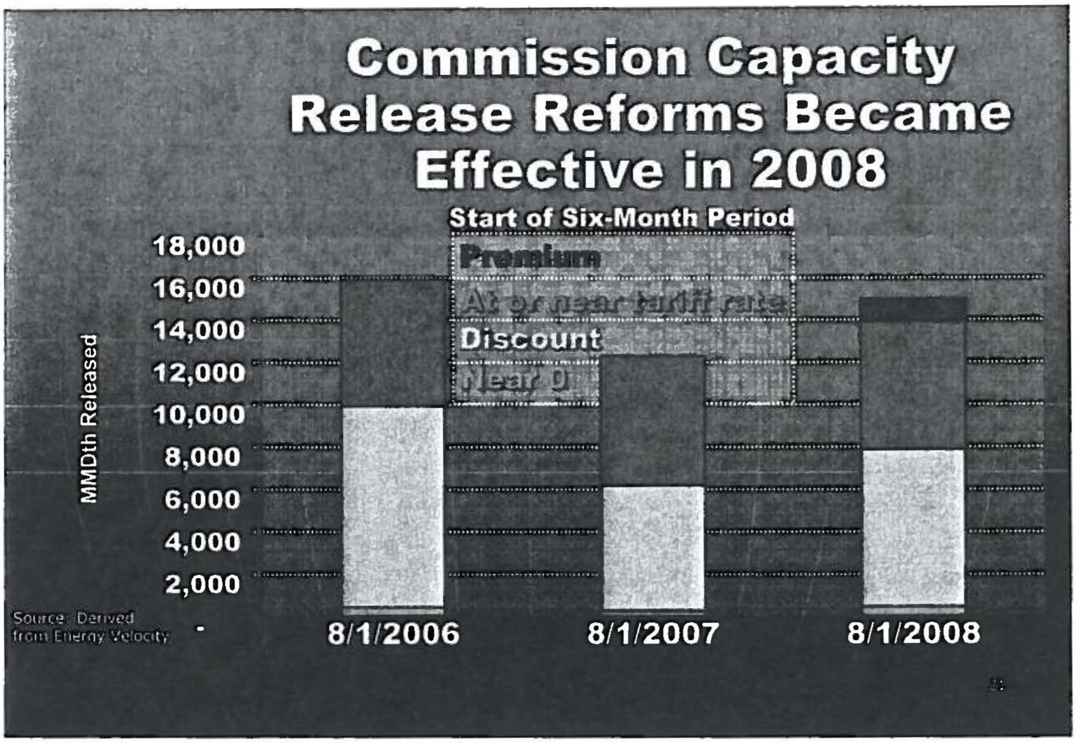
On January 6, 2009, the Midwest ISO commenced its new Ancillary Service Market. The market optimizes the sale and purchase of regulation service (generation that responds to load changes every few seconds), spinning reserves and supplemental reserves simultaneously with MISO's energy market.

On April 1, 2009, the California ISO commenced its new market referred to as the Market Redesign and Technology Upgrade (MRTU) market system. Among other features, MRTU offers a day-ahead energy market, locational marginal pricing (LMP), a process to co-optimize energy and ancillary services and a unit commitment process to maintain reliability.

On April 1, Omaha Public Power District, Nebraska Public Power District and Lincoln Electric System completed their transition to membership in the SPP regional transmission organization. The three Nebraska public power entities are now active participants in SPP's energy imbalance service market.

Finally, Southern Company developed a bid-based energy auction that will include both a day-ahead energy auction for firm-liquidated damages energy and recallable energy, and an hour-ahead energy auction for non-firm energy. Southern Company's energy auction is scheduled to begin next week on April 23.

We expect these developments to produce benefits with enhanced reliability and transparency, allowing buyers and sellers to transact with each other more efficiently and economically. Oversight staff will monitor these markets to determine whether they do so.



Finally, I'll note that the Commission's capacity release reforms pursuant to Order No. 712 became effective in August 2008. Since that time, removal of the price cap for released pipeline capacity has not substantially altered pricing in the capacity release market. In the six months following the effective date of the final rule, release above the cap comprised only 8% of all releases, 7% of all capacity released.

Capacity releases above the tariff rate are limited to one year or shorter. In 2008, about 59% of the premium-priced capacity released was for one year. Nonetheless, there is still a market for long-term releases at the maximum tariff rate. In 2008, about 58% of the capacity released at the maximum tariff rate was for a period longer than one year. If we consider the number of capacity release transactions, about two-thirds of the releases were monthly, regardless of the price of the released capacity. Geographically, most of the capacity released occurred on pipelines serving the Northeast and Midwest. About half of the capacity released on Northeast pipelines was at tariff rate cap, and another 6% was above the cap. In contrast, about 77% of capacity released on Midwest pipelines was discounted.

In Order 712, the Commission carved out exemptions to the capacity release rules to accommodate the development of asset management agreements. In an attempt to capture AMA activity, we compared customer/agent information in the Index of Customers to releaser/bidder information in the capacity release database. Instances where the bidder is identified as a pipeline customer's agent constitute a small share of the capacity release market, but that share did increase during the six months after Order No. 712 from 3% in 2007-08 to 5% in 2008-09. The largest growth occurred in long-term released capacity which tripled between the two periods. Initial research from OE's audit staff has indicated that AMAs tend to be executed near the beginning of the gas year, on April 1. This would mean that data still coming in will provide a more robust picture of Order No. 712's effect on the AMA market.

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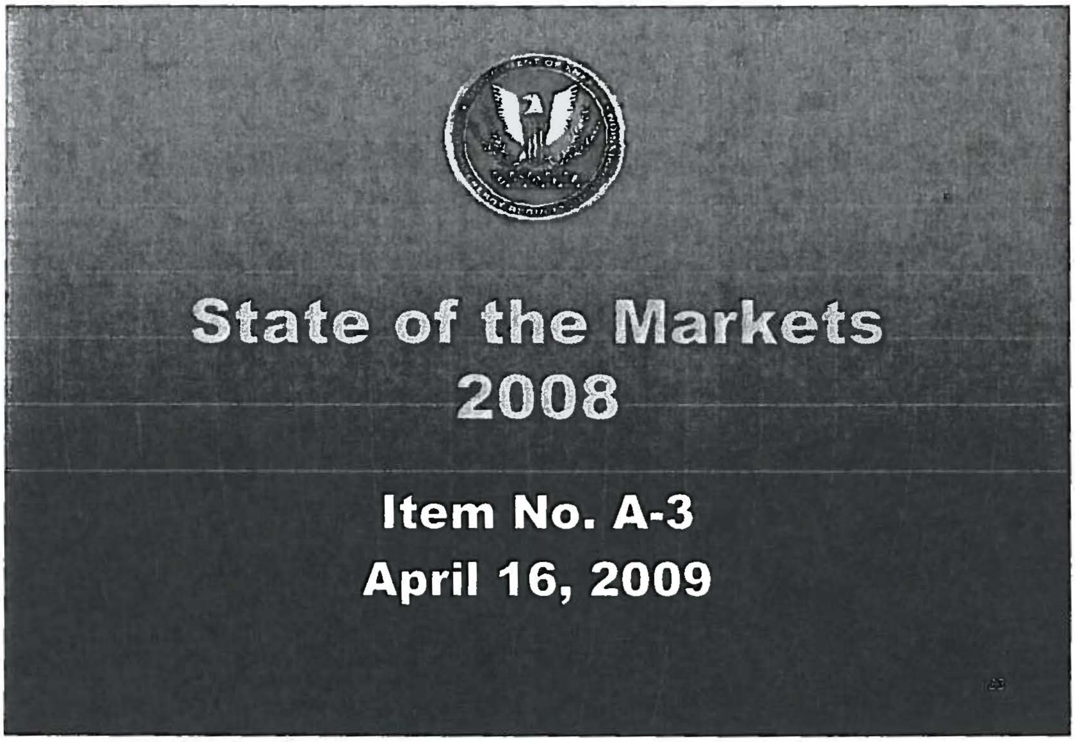
On the electric side, market participants that had reserved transmission service have been allowed to reassign that service above the tariff rate since Order No. 890 went into effect during the second quarter of 2007. There has historically been relatively little reassignment of electric transmission service. Since the second quarter of 2007, the quantity of transmission service that has been reassigned has increased steadily. Capacity reassignments occurred throughout the non-RTO markets, with no particular region standing out. The Mid-continent Area Power Pool has been the most consistently active region for reassignments, with Bonneville Power Authority's system displaying a large increase in the fourth quarter of 2008. The majority of completed transmission capacity transactions were for less than a day, though on a MWh-basis yearly and monthly reassignments comprise the vast majority of reassignments.



This concludes our presentation, we would be happy to answer any questions.