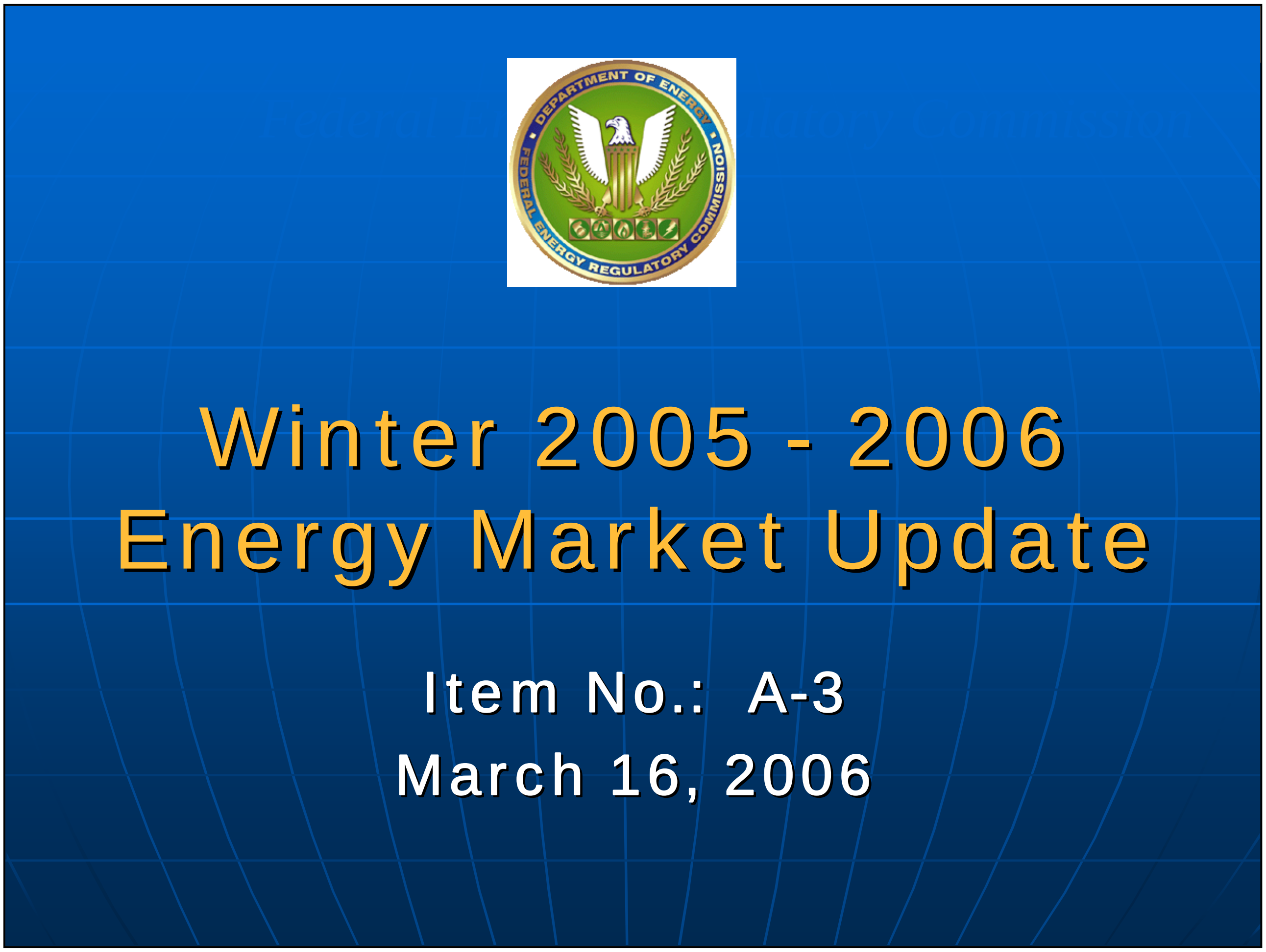
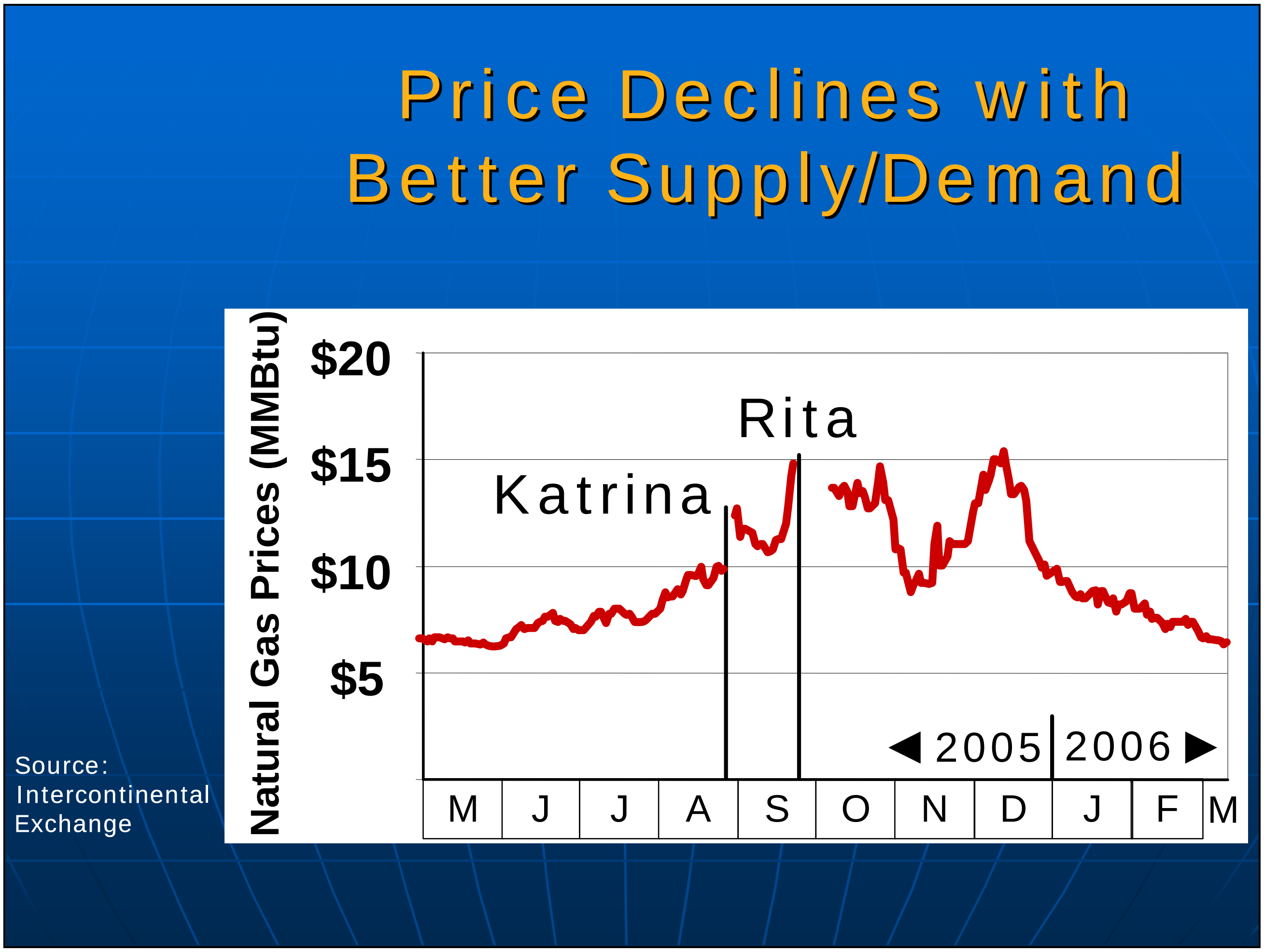
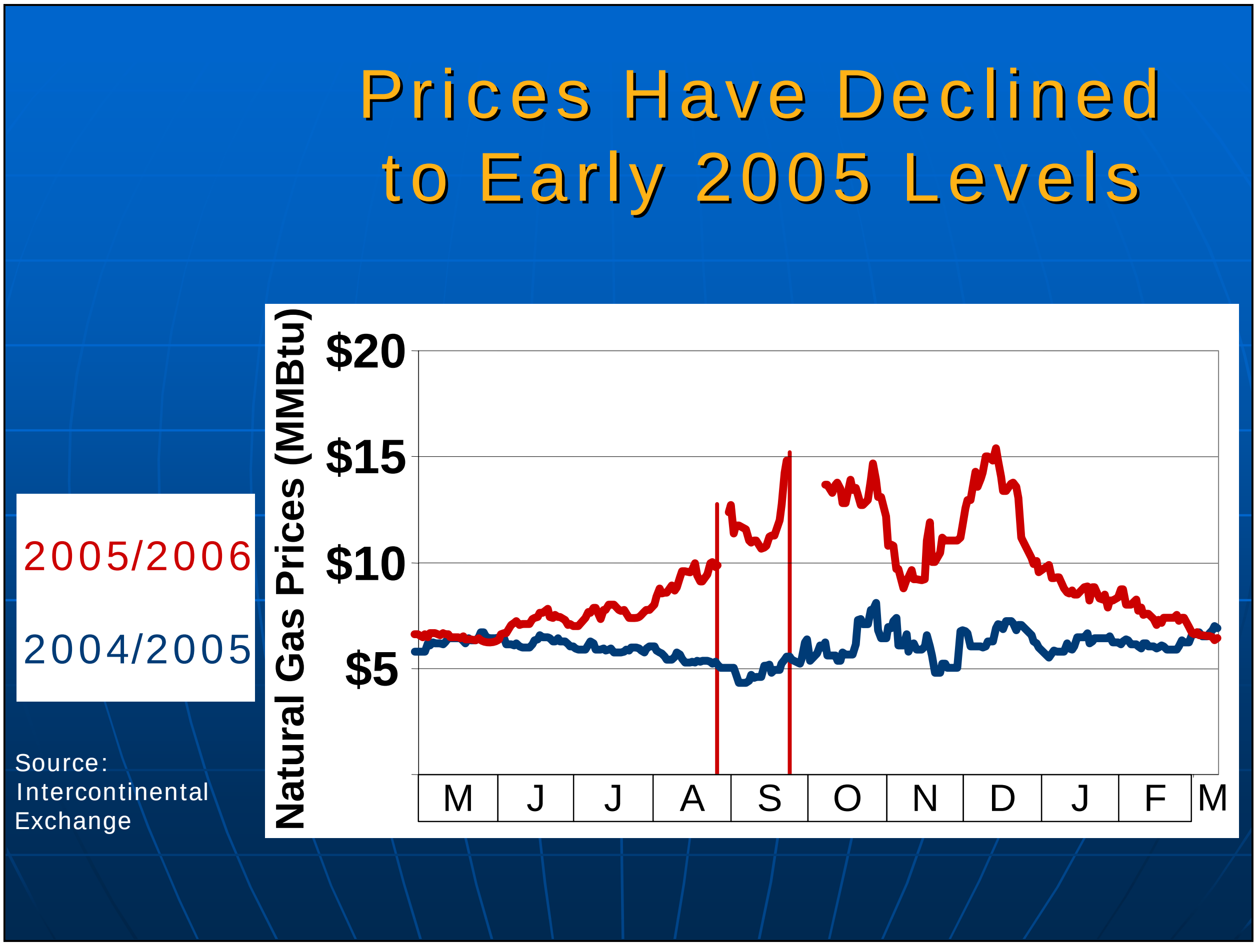


Good morning Mr. Chairman, Commissioners.

My name is Steve Harvey and along with Jeff Wright we would like to present our last regular review of U.S. natural gas market conditions for the winter of 2005/2006. I'll start by reviewing current prices and market conditions and then spend a minute or two on remaining issues. Jeff Wright will then explore related storage capacity and operations issues in greater detail.

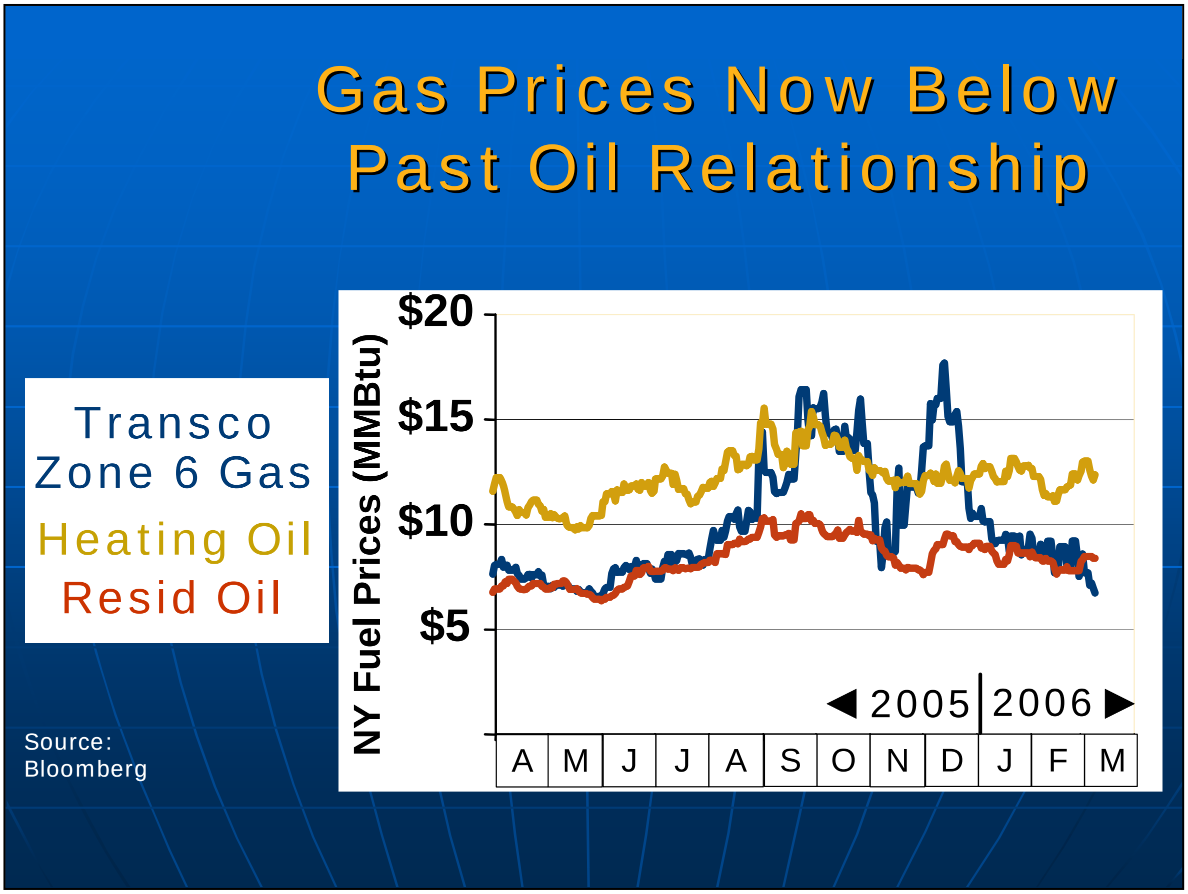


Prices in late February and early March have continued the downward trend we observed last month, dropping last week into a range around the mid- $6.00 per million British thermal units (or MMBtu) level. This week, prices rebounded some to around $7.00/MMBtu. In trading Wednesday for gas delivered today at Henry Hub, Louisiana, prices averaged $7.10 on the IntercontinentalExchange. To put these prices in a historical context, let me superimpose last year's prices at Henry Hub for the same dates.



The red line is from May 2005 through last week; the blue line is from May 2004 through early March 2005. This chart shows that prices in early March have fallen back below where they were a year ago at the same time – the first time this has happened at Henry Hub since June 2005. Early this week, prices rose back above last year's levels, but, as of yesterday prices were 5 ½ cents below last year in trading on March 15.

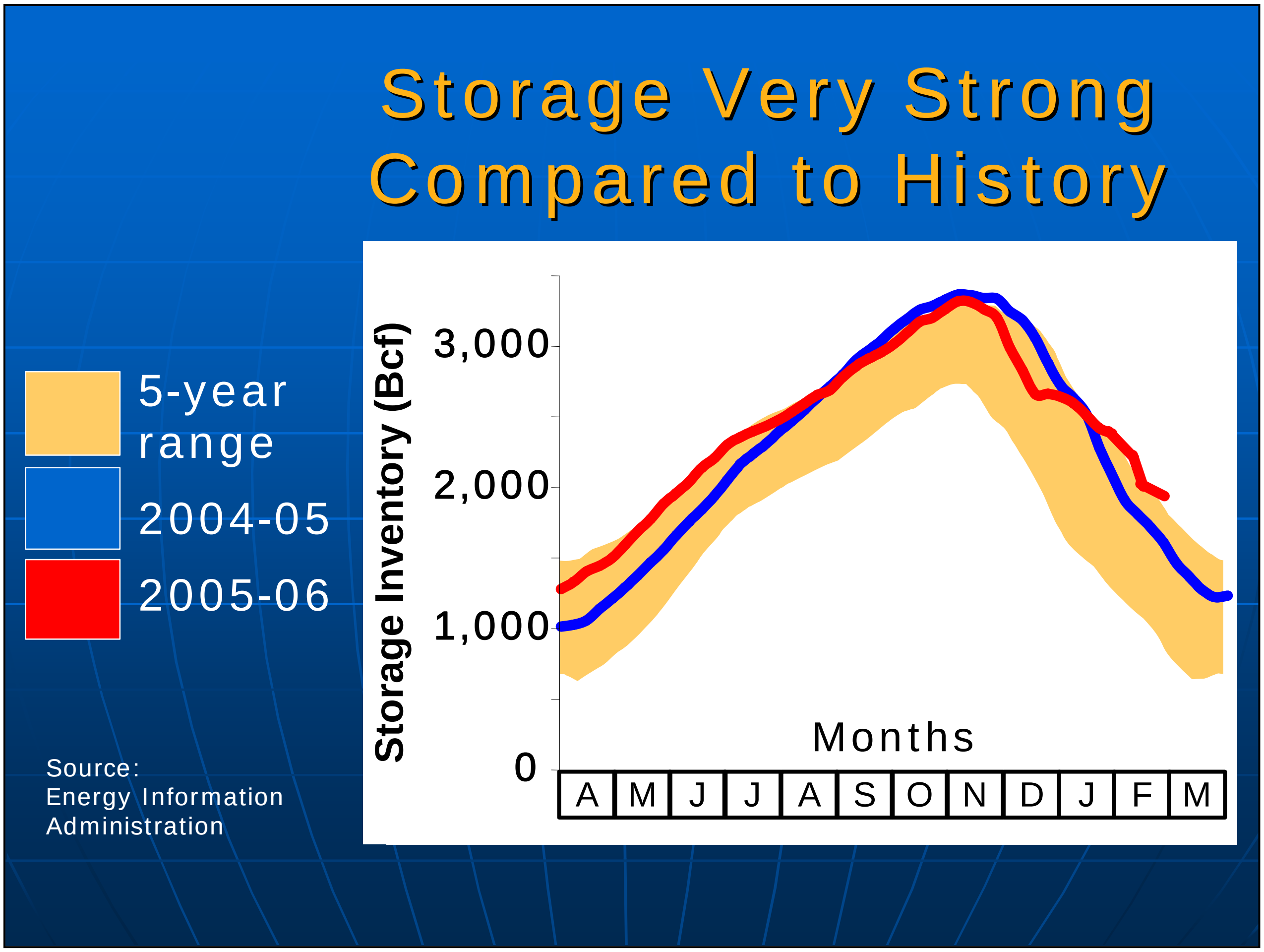
Like at Henry, prices across the country remain close to where they were last year at this time. As least for the next-day physical market, we've seen the end of the cycle of higher prices that started last summer with record natural gas demand for electric generation, and continued because of the damage done by hurricanes Katrina and Rita.



Why haven't prices fallen further? I pointed out the relationship between oil and gas prices here a few months ago. Gas prices rarely fall much below competing fuel oil prices for any substantial period of time. Because of the availability of the relevant prices, New York shows these relationships best and New York prices are plotted on this graph. We can see by comparing the blue line that represents wholesale gas prices in New York and the red line that represents residual fuel prices in New York that gas prices have recently fallen below resid prices. Price increases earlier this week for gas were matched by oil products, so this relationship still holds today. While gas prices falling below competing fuels is not a typical condition, I'll restate what I said in January about the possibility:

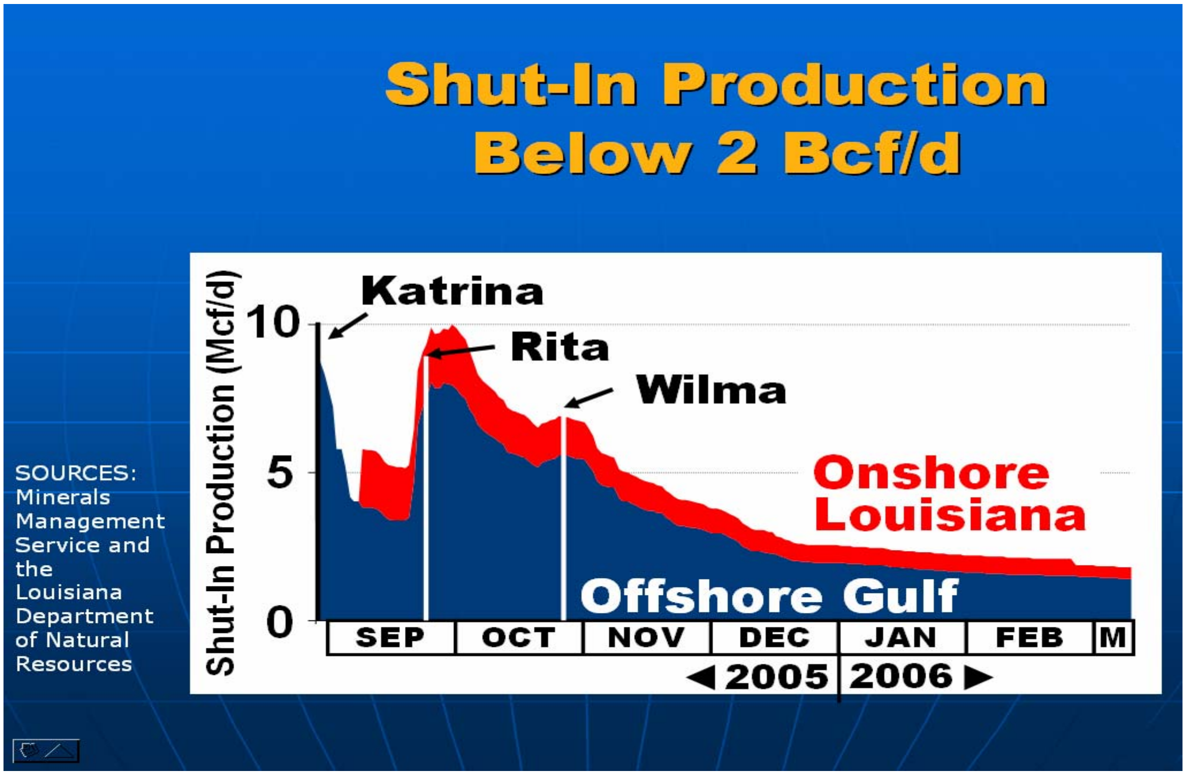
> I could conceive of a situation where this alternate fuel floor would not hold and gas prices could plunge – if so much inventory was still in storage at the end of the winter that physical operations required its owners to remove it no matter what the price. This condition seems unlikely unless current warm weather conditions remain through February.

In fact, though February was not nearly as extreme a month as January, we've seen this scenario play out in this way.

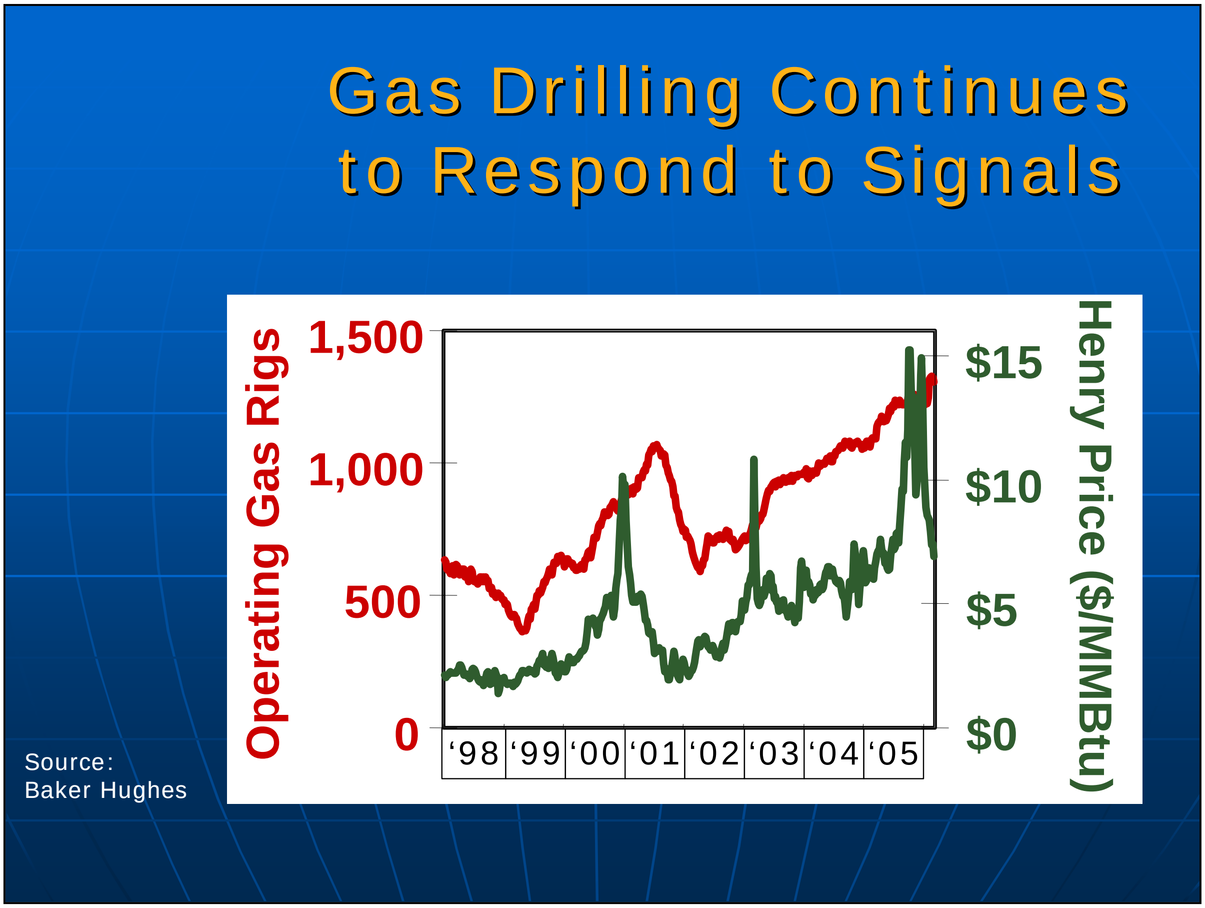


Consistent with that last observation, storage inventories are very full at this time. The Energy Information Administration last week reported that storage inventories for natural gas reached recorded highs for this point in the withdrawal cycle—664 billion cubic feet (or Bcf) above the 5-year average or 54 percent higher than normal.

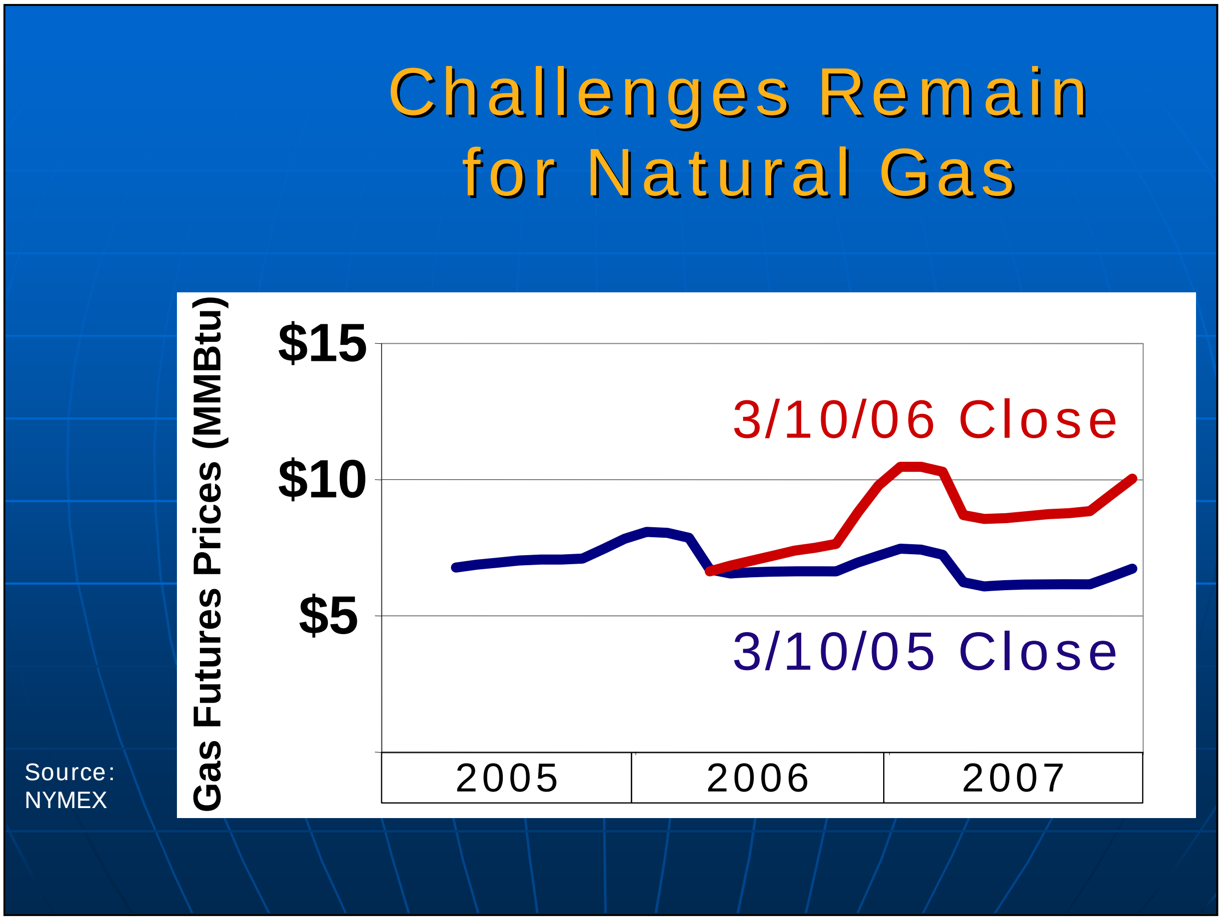
With so much gas in storage and without abnormally cold weather, the requirements to withdraw have created competition between wellhead production and storage withdrawals. That competition has driven down price—at least to where oil prices limit more price decreases. LNG imports have remained extremely weak due to more attractive prices in Europe and Asia. As the United States carries this very strong storage position into the spring and summer, we could see further weakening of prices. Certainly, in the absence of strong weather-related demand, high storage inventories are likely to be a continuing factor in determining natural gas prices throughout 2006.



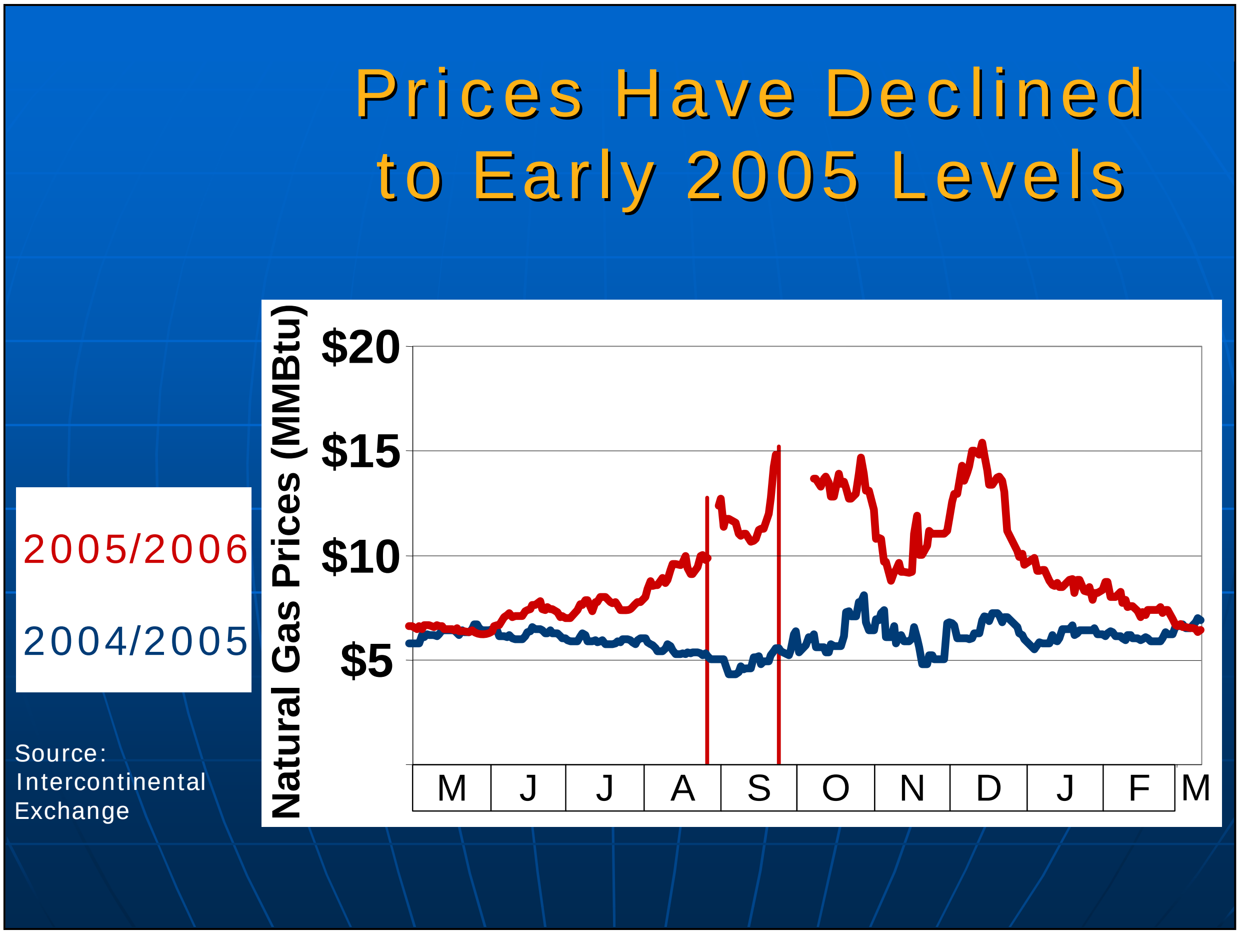
In addition, recovery of Gulf production shut-in by the hurricanes last year continues to improve, although at a considerably slower pace. The most recent reports from the Minerals Management Service and the Louisiana Department of Natural Resources indicate that total production shut-in in Louisiana and in the Gulf of Mexico has fallen from highs of close to 10 Bcf per day immediately after Rita's landfall to less than 1.8 Bcf/d as of March 8. At 1.8 Bcf/d, a total of less than 4 percent of U.S. production remains unavailable, and with current healthy storage inventories, still shut-in gas represents no immediate threat.



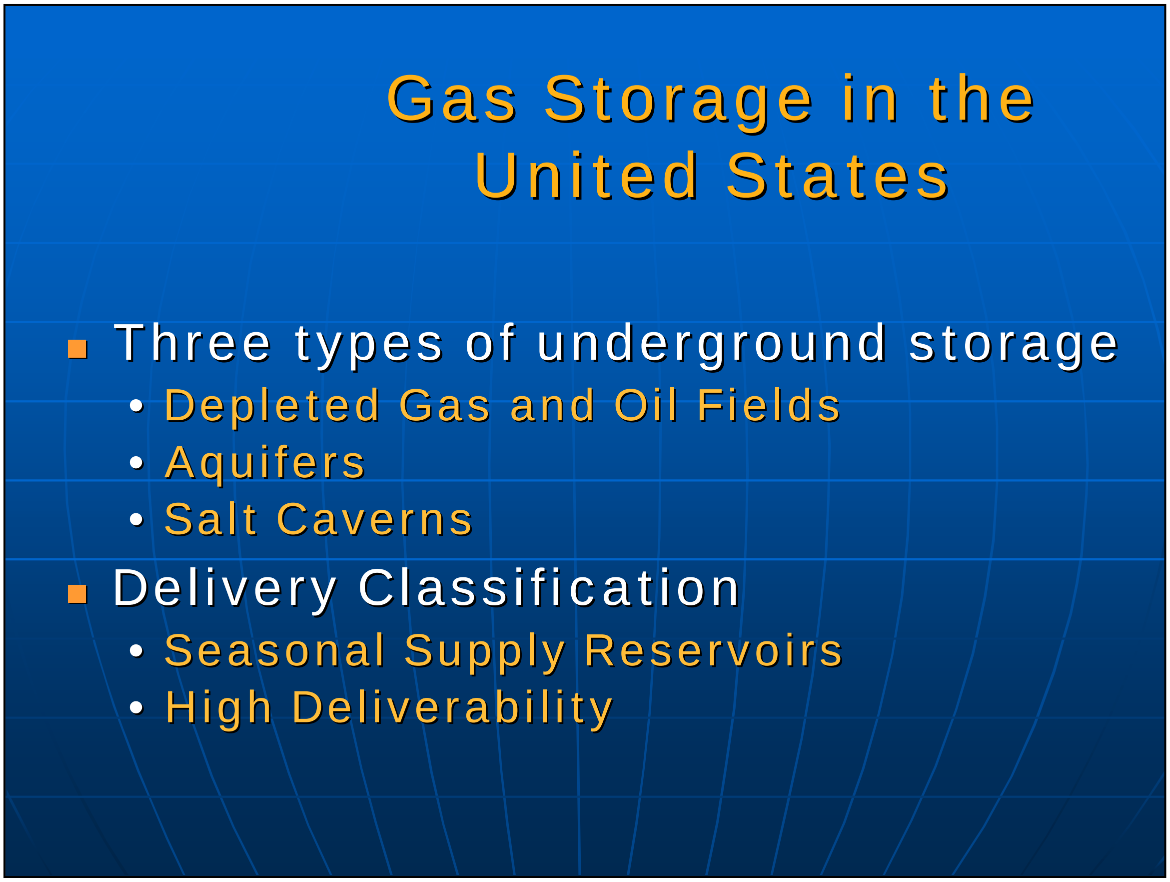
We continue to see very active U.S. drilling for natural gas, despite reductions over the past few weeks. The Baker-Hughes rig count for natural gas was reported as down slightly in early March, but still quite close to two-decade highs. As you can see on the graph, natural gas drilling (in red) has clearly been responding to prices (in green) throughout the past eight years. Last fall, after a warm summer and the passage of two destructive hurricanes through a major U.S. production region, prospects did not look good for natural gas markets. Today, prospects look much better. The reason clearly was extraordinarily mild weather across the United States from late December through early February. As a result, wholesale natural gas inventories are high, drilling is active, production in the Gulf is recovering and prices have returned to levels lower than those seen last year at this time. Nevertheless, I'd like to close with two somewhat less sanguine observations.



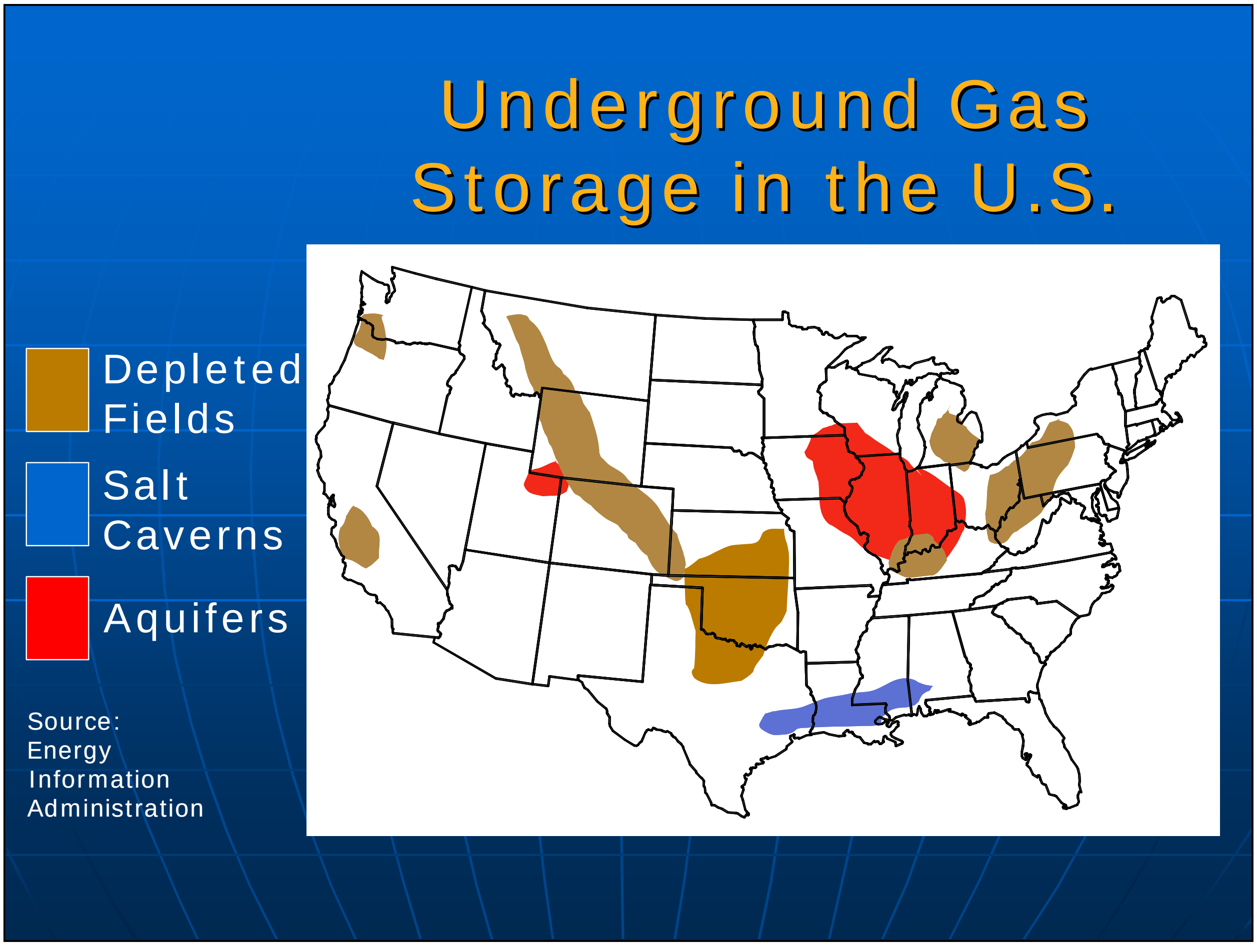
First, futures markets are clearly assigning some possibility to price increases as 2006 continues. Currently, April natural gas futures are at the lowest price traded – lower than futures price all the way to December 2011. What is striking on this graph is that, despite recently similar spot prices, at last year at this time, the futures curve has risen from last year at this time. The curve in red is the path of futures prices as of the New York Mercantile Exchange's close last Friday, and the blue curve is for one year earlier. We see that expectations for April 2006 are similar, but the rest of the curve has shifted up by about $3.00 next winter and a little more by the next. In other words, market participants' assessments of the risk of higher prices have increased over the last year. Remember, from this graph, that spot prices are back around last year's levels, but concerns about the future have been heightened.



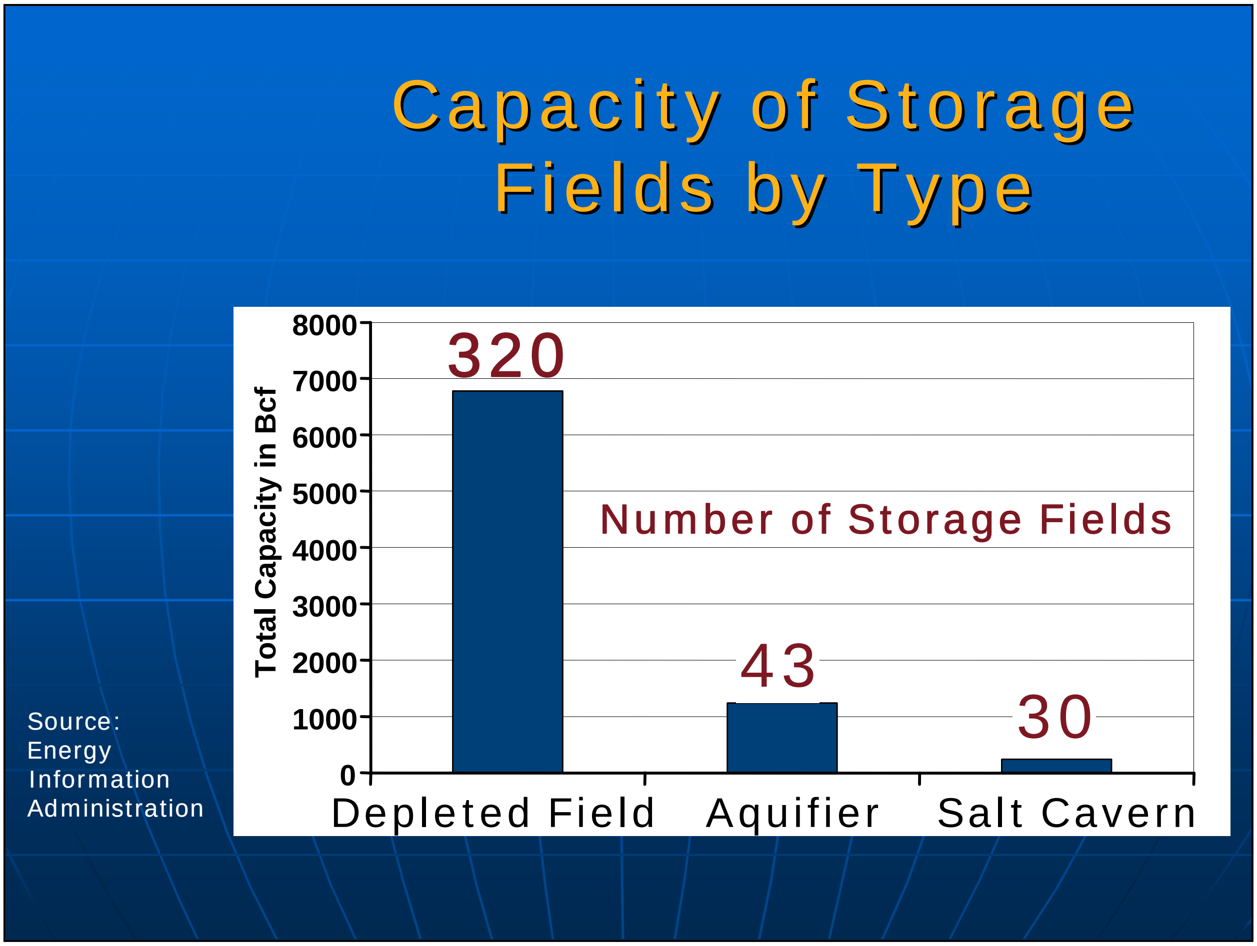
The second observation regarding future gas prices starts with the reminder that all the prices I've shown are from wholesale markets. There is a difference in prices between wholesale and retail. Today, distribution companies and others are withdrawing gas from storage that was injected last summer at prices higher than today's spot prices. These retailers have to make these withdrawals – the physical integrity of the storage fields requires it. Jeff will speak to the technical issues involved in a minute. But, as a consequence, retail rates will not drop as fast as these wholesale prices have. While this may be frustrating, these costs are real and necessary. Filling natural gas storage adequately every fall and empting that storage every spring is vital to protect the natural gas markets from additional volatility and the possibility of not delivering at times of stress. We enjoyed a mild winter this year, but that is no guarantee that next winter will be the same. The U.S. natural gas system has been under severe stress due to cold winter weather before – most recently in February 2003. Under those conditions prices can rise explosively, and even put the reliability of deliveries under threat. The higher cost supplies now entering the retail system – assuming they were prudently acquired in the first place – represent a real cost of the industry's regular preparation for the possibility of occasional extreme cold weather. In general, prospects for more moderate prices than those experienced last fall are quite good in 2006. Now I'll turn the presentation over to Jeff.



Let me briefly give you a background on underground natural gas storage in the United States. There are three major types of underground reservoirs that are used to store gas. The first type is depleted gas or oil fields which is the most common type of underground storage. These formations are suitable when: 1) there is adequate space or porosity in the formation; 2) there is sufficient permeability such that can the gas be easily injected and withdrawn through the storage formation; and 3) the gas injected into the formation is retained, that is, it does not migrate to unrecoverable areas. The second type of underground storage is aquifers. Aquifer storage consists of injecting gas in formations that are filled with water and displacing that water. The third type is salt cavern storage which consists of removing layers of salt through solution-mining and removing the resulting brine, which creates a cavern to store gas. Deliveries from these three types of storage facilities can either be classified as seasonal supply reservoirs or high-deliverability sites. Usually, seasonal supply reservoirs are filled during the traditional non-heating season from April through October and the inventory is drawn down during the heating season from November through March. The depleted fields are typical of seasonal supply reservoirs. High deliverability storage sites, typified by salt caverns, have rapid injection and withdrawal cycles and can go through several complete cycles during a heating season. This makes them well suited to meet severe peaking needs or as an emergency source of gas. Aquifers can be categorized as high deliverability or as seasonal supply reservoirs depending upon the individual field.

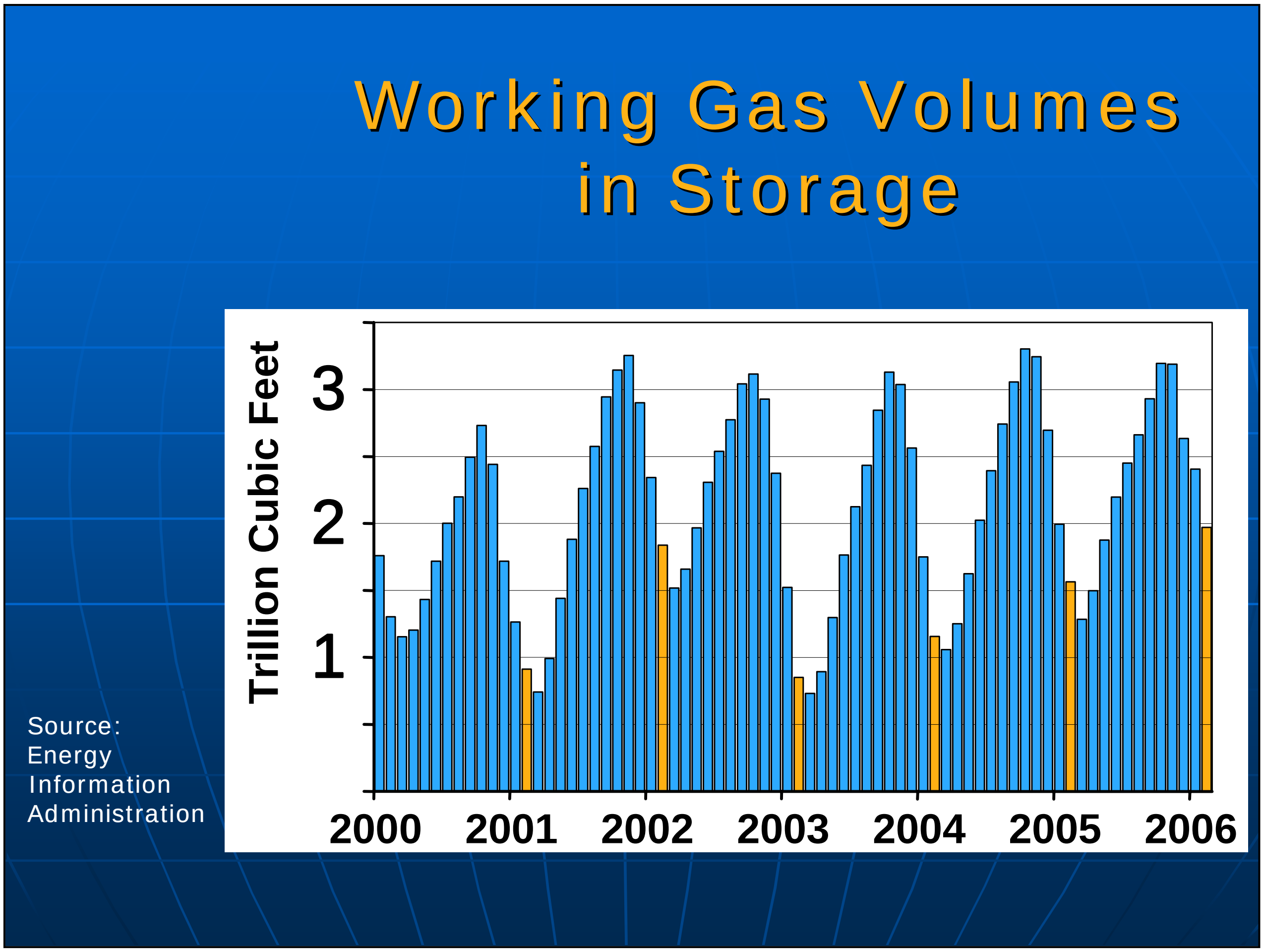


At the end of 2004, the Energy Information Administration of the Department of Energy stated that there are 393 active storage fields in the United States. Storage in the eastern part of the U.S. is characterized by depleted reservoirs and aquifers with a few salt caverns. It is noteworthy that there is no underground storage in New England due to the geology of the region. Storage in the Gulf Coast is made up of a mixture of depleted gas, oil fields and salt caverns, while storage in the West primarily consists of depleted fields.



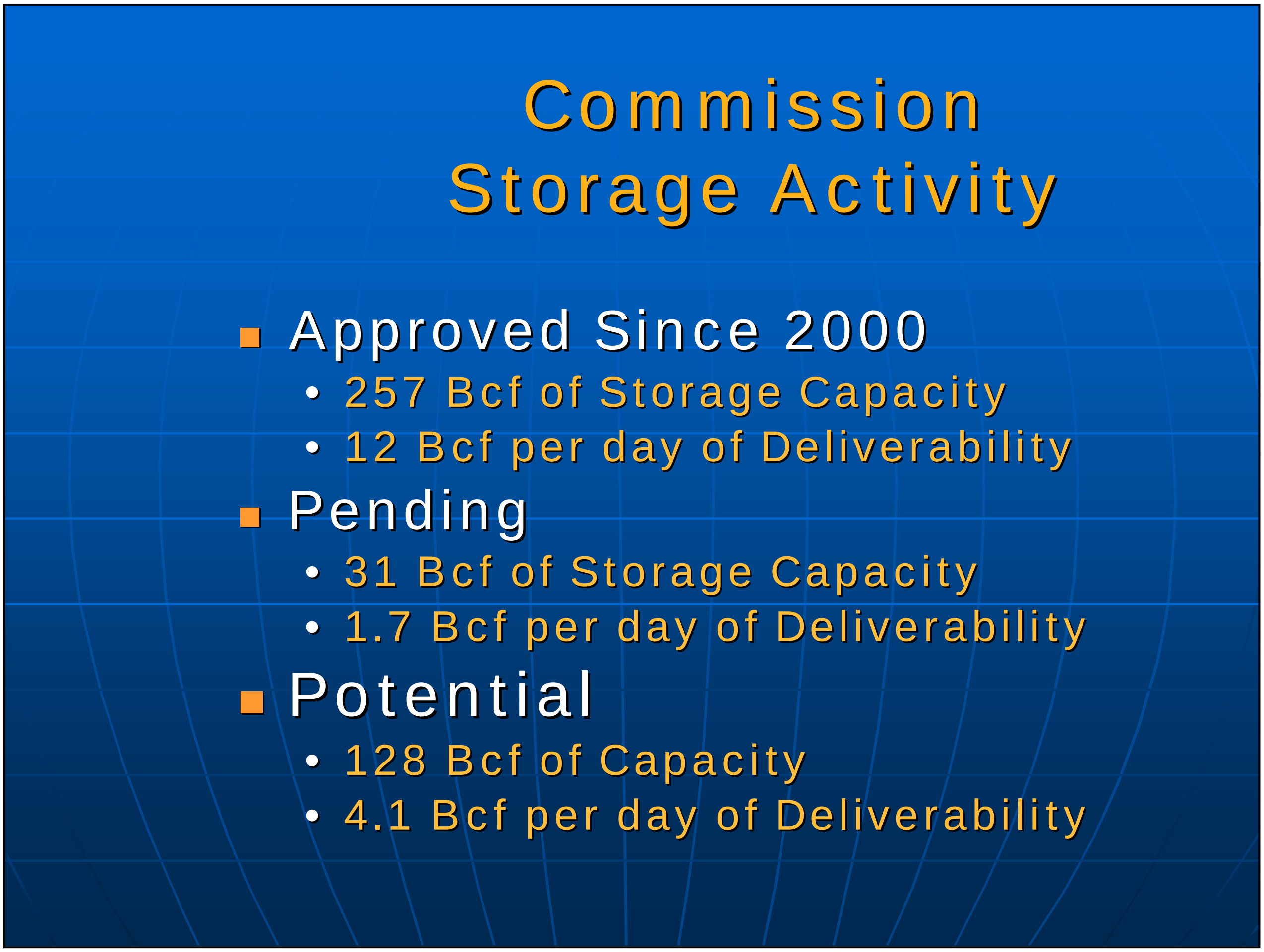
The storage capacity of any given storage field consists of two components – the base or cushion gas that must remain in the storage field to provide the pressure necessary to extract the other component, the working gas, which is the gas that is being stored and withdrawn.

Total storage capacity, base gas and working gas, totaled a little over 8.2 trillion cubic feet for 2004 according to EIA. Depleted gas field storage accounted for 6.8 Tcf of this total, or 82 percent of the capacity in 320 fields. Aquifers made up about 1.2 Tcf or 15 percent of the capacity in 43 fields. And, the capacity of salt caverns totaled a little more than 0.2 Tcf or around 3 percent of the capacity in 30 fields.



This slide gives you the idea of the working gas volumes that cycle in and out of storage on a monthly basis from the beginning of 2000 through the end of February 2006. The peak amount of working gas in storage, usually reached in October of every year, has not significantly changed since 2001. What has changed is the amount of gas in storage in February of every year, as depicted by the lighter color, yellow bars. With the exception of February 2002, which was a warm winter, the amount of working gas in storage has increased since 2000 to the highest level of working gas that we have seen in storage in February. In short, there is slightly more than 400 Bcf working gas in storage than there was at this time last year.

Isn't this surplus a good thing? Well, not necessarily. Most of this gas is stored in depleted gas and oil fields. As I mentioned earlier, these storage fields are seasonal supply reservoirs, usually have just one withdrawal cycle during the course of the year. Based on the individual characteristics of the storage field, a certain amount of gas needs to be withdrawn by a specific time in the spring. Many gas tariffs of storage operators specify the maximum amount of gas that their customers can have in storage at the end of the heating season. This is to sustain the physical integrity of the storage field. If gas is not withdrawn by a specific time, the high pressures in the storage field could cause an unwanted expansion of the reservoir, causing gas to migrate and become unrecoverable. The proper recycling of the storage reservoir is the major tool in the prevention of the unwanted migration of gas. And, of course, the loss of gas is definitely an unwanted economic effect.



So, does this seeming oversupply of working gas in storage indicate that there is too much storage capacity? No, because again we come back to the weather. Over the injection season, gas was prudently put into storage in order to prepare for the cold weather of winter. However, as we know, there has not been a truly prolonged cold spell this winter, and the high level of storage inventory at this time of the year is indicative of this. It is important to not be shortsighted. There will be cold winters again and gas demand will increase. The ability to store natural gas will be crucial in meeting our peak demands in coming years. In fact, I would like to note that overall U.S. working gas storage capacity has actually declined from about 4.3 trillion cubic feet (Tcf) at the beginning of 1989 to about 4.0 Tcf as of December 2005, a decrease of approximately 6.5 percent. As Steve and I have said over the last few month, declines in domestic production will be somewhat replaced by 1) higher cost non-traditional production; and 2) Canadian imports, which did step up last fall due to increased Canadian drilling activity; but that does not seem to be sustainable at historic levels over the long run. As demand increases, the increasing supply/demand gap will have to be filled by LNG and Alaskan supplies. However as we've seen this past winter, some LNG supplies can be bid away from U.S. markets. An excellent way to overcome the need for more gas availability to meet demand is to construct more gas storage. This allows not only domestically-produced gas to be put underground for cold weather consumption, but also LNG, which can be delivered, regasified and stored during those months when LNG is not in high worldwide demand.

The Commission has been active in processing applications to build more storage in the U.S. Since 2000, the Commission has approved numerous projects that total 257 Bcf of capacity and almost 12 Bcf per day of deliverability. Currently, the Commission is processing storage projects totaling 31 Bcf of capacity and about 1.7 Bcf per day of deliverability. The majority of this new capacity and deliverability is centered around three projects: Bobcat Gas Storage field in Louisiana, an expansion of the Stagecoach facility in New York and the Windy Hill Gas Storage Project in Colorado. Both Bobcat and Windy Hill are high-deliverability salt cavern projects. On the horizon, we see storage projects with the potential to store 128 Bcf of gas and deliver 4.1 Bcf per day. While these appear to be large numbers, we can see that in recent years the peak amounts of working gas in storage have not changed. In fact, there was more working gas in storage at the beginning of the 2001-2002 and 2004-2005 heating seasons than the current heating season.

Let's again look at the question, "why is more storage needed?" As you have stated on several occasions, Mr. Chairman, and as echoed in the Notice of Proposed Rulemaking entitled Rate Regulation of Certain Underground Storage Facilities, or the Storage NOPR, customers will be better off if more storage infrastructure is built because it increases customer alternatives in a market and mitigates price volatility. And, based on the approach described in the storage NOPR, additional development of appropriate storage infrastructure is the expected outcome.

I mentioned earlier how regasified LNG can dovetail nicely with storage, but there are additional, hidden synergies between LNG and underground gas storage. In the Gulf area, where most high-deliverability storage fields are located, the Commission has certificated seven LNG projects with a daily send-out capacity of 11.2 Bcf beginning with the Cameron project in 2003. Several more LNG projects at new sites and expansions of already-approved sites in the Gulf area are pending with a combined daily sendout capacity of 13.2 Bcf. If built, these LNG import terminals will have a significant amount of onsite storage in large cryogenic tanks; however, until the LNG has been vaporized and those tanks emptied, LNG tankers cannot deliver additional cargoes. ¶

Additional storage, proximate to the import terminals, can provide a solution. Vaporized LNG can be sent out, not for immediate consumption, but instead for redelivery into storage. This would allow for a more consistent turnover of LNG and a more efficient utilization of the LNG import facilities.

At the other end of the transportation grid, the presence of LNG in the market area of the Northeast could help in the more effective utilization and development of market area storage. That is, as LNG is delivered into the Northeast, traditional gas supply from the South will not have to travel as far north, and importantly, the regasified LNG then can be stored in the storage areas of Pennsylvania and New York. In the winter, under this scenario, it will not be necessary for the traditional southern gas supplies to fill the pipelines in the Northeast market areas, especially in New England, which has stifled the efficient use of storage.

Such an infusion of market area LNG could send the appropriate price signals and lead to new consideration being given to additional storage infrastructure development. This, coupled with the new approaches offered by section 312 of EPAct and the Commission's proposed refinement to its storage pricing policy, should stimulate such development, thus increasing customer choices in the market and serving to mitigate pricing volatility. That concludes our presentation. Steve and I would be happy to answer any questions you may have.