



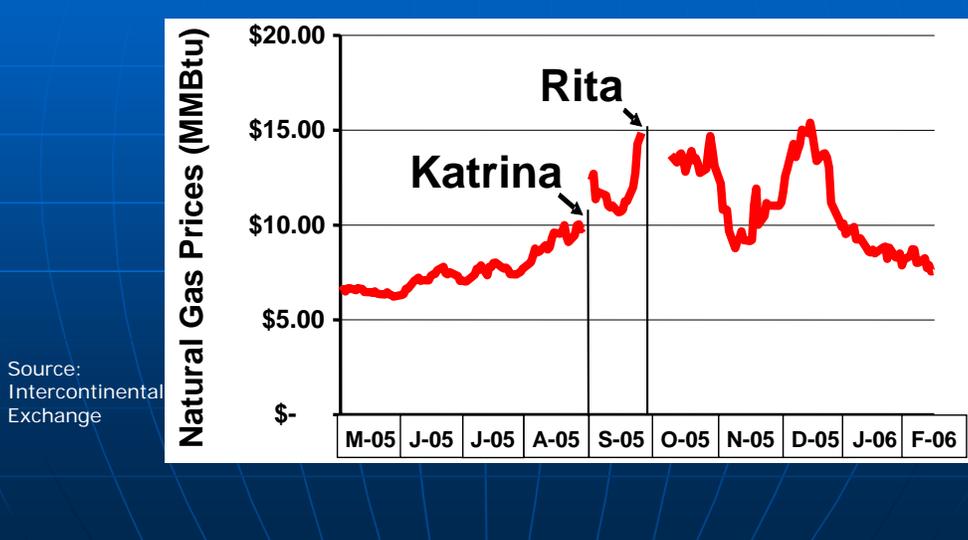
Winter 2005 - 2006 Energy Market Update

Item No.: A-3
February 16, 2006

Good morning Mr. Chairman and Commissioners Brownell and Kelly.

I'd like to review U.S. energy market conditions as we near the end of the 2005/06 heating season, review prospects for the gas market, and finally, spend a little time discussing recent staff research of electric generation investment patterns in 2005. At that point, Jeff Wright will take over to discuss LNG activity and storage and pipeline infrastructure investment efforts.

Gas Prices at Summer Levels With Mild Winter



Since we last reviewed natural gas market conditions on January 19, prices for gas in the United States have continued to moderate, dropping to about \$7.30 per million British thermal units (or MMBtu) in trading Wednesday for gas delivered today at Henry Hub, Louisiana. That price represents less than half of what it was at its recent high during a period of post-hurricane cold weather last December 13. The last time we saw a price this low was in trading on July 1, 2005. The current price is about a dollar higher than in mid-February 2005.

The price differences between the eastern and western parts of the United States that I pointed out in December have largely disappeared. These differences were related both to facilities outages and to the location of disrupted Gulf production, that tends to be better connected to the east. With the continued improvement in Gulf production and prevailing market conditions I will discuss next, the market rationale for east/west differences appears to be gone.

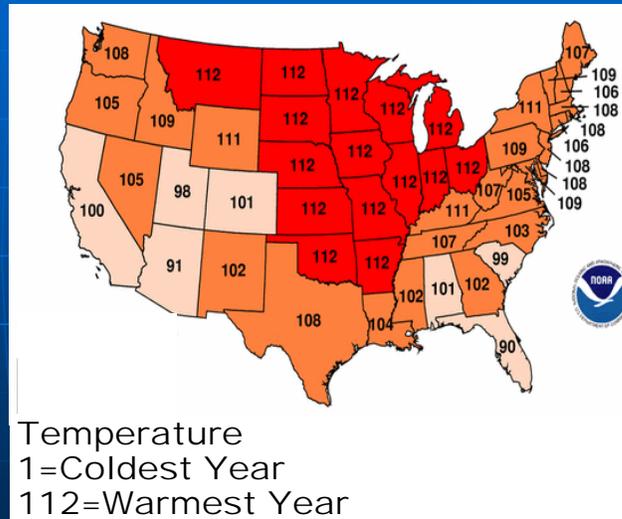
Record Mild January Reduced Demand

Record Warmest

Much Above Normal

Above Normal

Source:
National Oceanic and
Atmospheric Administration

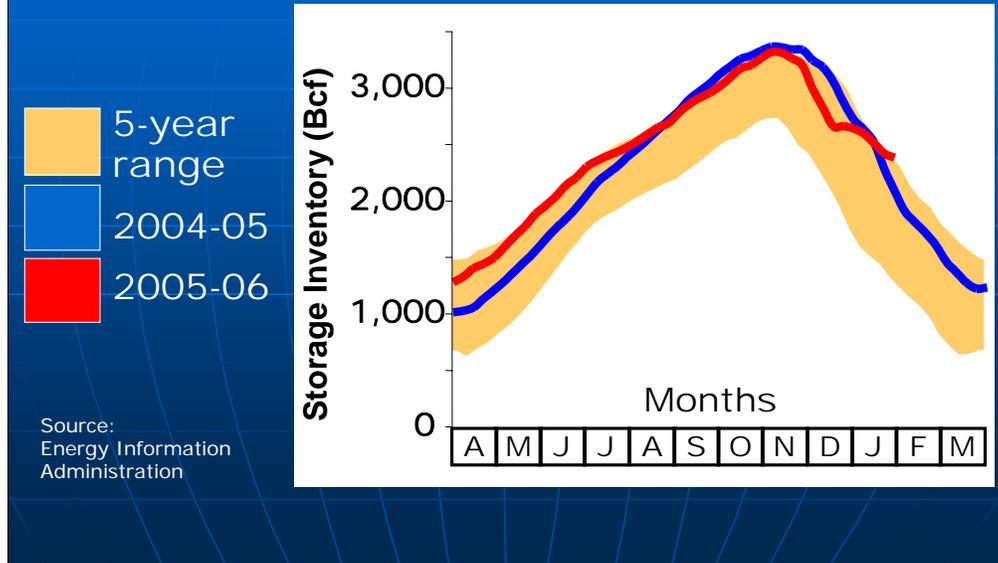


The weather in January was extraordinary. There is no other word for it. January was the warmest in the full 112 years tracked by the National Oceanic and Atmospheric Administration or NOAA. Temperatures averaged $8\frac{1}{2}$ degrees above norms. This map, produced by NOAA, shows how widespread the warm weather was. Fifteen states in the northern Plains, Great Lakes and Midwest, shown in red on the map, had their warmest January in 112 years. NOAA identified an additional 26 states as above average, shown in orange. The “coolest” state in January was Arizona, which nevertheless had its 21st warmest January in 112 years.

NOAA scientists estimate that residential energy needs in January were 20 percent less than under normal temperatures. Consistent with that estimate, figures released by the Federal Reserve yesterday indicate that natural gas deliveries fell 15.0 percent from December to January.

This record warm spell followed the 9th warmest November and a roughly average December. In all, this winter’s extraordinary weather and the resulting weak energy demand has resulted in gas market conditions we certainly couldn’t have predicted in the Fall.

Storage Now Above 5-Year Highs



For example, storage inventories for natural gas last week reached above the previous 5-year range. Inventories last week were 649 billion cubic feet (or Bcf) above the 5-year average – almost 38percent. Today’s report of a 102 Bcf withdrawal was right at expectations, resulting in continued high inventories.

Instead of being short of supply, the industry now faces the task of getting enough gas out of storage by the end of March, considered the end of the heating season. For physical operations reasons, inventories for most storage facilities have to fall to certain levels to maintain their integrity. As of today, even historically strong withdrawals for the rest of the season could easily result in record high inventory levels on April 1.

This is a remarkable story. After starting the winter in a strong inventory position but with real concerns as to the availability of supply from the Gulf for the winter, our literally 1-in-100 chance warm weather has resulted in a current surplus of gas inventory. We bet, as a country, on mild weather, and we hit the jackpot.

I noted last month the “kink” in withdrawals you can see on the graph in mid-December, where the red line had been moving down the middle of the 5-year range, but then appeared to turn and has now reached slightly above the band. At that time, we observed less gas being withdrawn from storage per heating degree day than we’ve seen in the past. We now think that there are three basic reasons for this.

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First, as I've already indicated, the weather for the last week of December and through January was so mild that it didn't function like a winter month, more like a "shoulder period" (or mild fall or spring) month. Consequently, demand was reduced even more than a less extreme variation of temperature would predict.

Second, reductions in demand may have been the result of decisions by customers to change their behavior – what I'll call a "demand response." We've noticed anecdotal evidence of a demand response to the high prices of the early winter in the form of more attention to, for example, lowering thermostats and taking other energy-saving actions. Almost certainly, high November and December gas bills changed customer behaviors. In addition, the Department of Energy and many state and local authorities have made significant efforts this winter to encourage conservation.

Third, high prices are likely to have had a supply effect as well. Evidence for a supply response is also anecdotal, but compelling. For example, rig counts surged recently to record highs not seen since the early 1980s.

More directly, Bentek Energy, consultants who follow pipeline flow information closely, released a report last week titled "Gas Market Fundamentals" that reports their insights into supply trends. To quote their findings, Continental U.S. production is dramatically responding to the current high price environment. . . . Basins having the greatest increases are Ft. Worth (17 percent), Uinta-Piceance (16 percent), E. Texas (11 percent), Arkla (10 percent), Raton (9 percent) and Wind River (6 percent). . . . Were it not for the hurricanes, U.S. production would have increased by 2.7 percent over 2004. The basins Bentek identifies as showing growth are significantly smaller than the Gulf Coast production, but their combined effects are material. Storage inventories are the most immediate signal we receive of supply/demand balance issues in U. S. natural gas markets. However, storage inventories do not identify the relative contributions of what forces are at play – they could be demand- or supply-related, or both. When the Energy Information Administration's detailed statistics on consumption and production patterns are compiled and released later this year, we will study them to detail the relative influences of supply and demand responses.

Factors Influencing Gas Markets in 2006

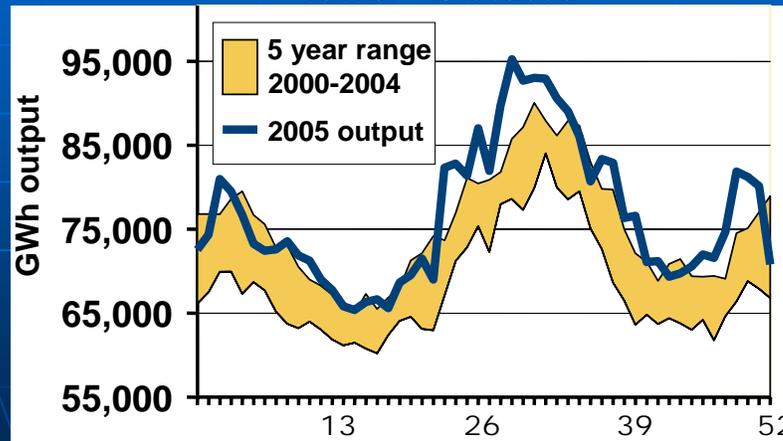
- Extreme effects on supply (hurricanes) and demand (January weather)
- Apparent responses to price by both supply and demand
- Anticipation of oil prices and summer weather

Several factors appear to be influencing where the U.S. natural gas markets are likely to head next. The first is the history of extreme weather disruptions in the recent past – hurricanes and mild winter weather – resulting in an initially strong storage position. The second may be long-lived responses to historical and future prices by customers and producers. A last set of drivers at play include expectations about the price of oil and the possible effects of summer weather. Remember that last summer was warmer-than-average, and that oil prices are still rather high – just recently creeping below the \$60 per barrel range. Last month I showed how high oil prices create something of a floor for gas prices. At this point, we are watching to see whether that floor will hold in the face of extremely high storage inventories and possible demand and supply responses to price.

One way of assessing current expectations of energy prices is to examine futures prices. Futures are in no sense a predictor of future prices because futures prices include other forms of value than just expected supply and demand. Still, their patterns reflect current expectations of buyers, sellers and others interested in energy markets. Currently, futures are indicating an expectation that prices today are about as low as they are likely to be for the remainder of the decade. Winter futures prices are in the \$10.00/MMBtu range while summer futures, including this summer, are higher than the current spot price.

Electric Generation Growth Was Strong in 2005

EI Weekly Output US 2000-2005
lower 48 states

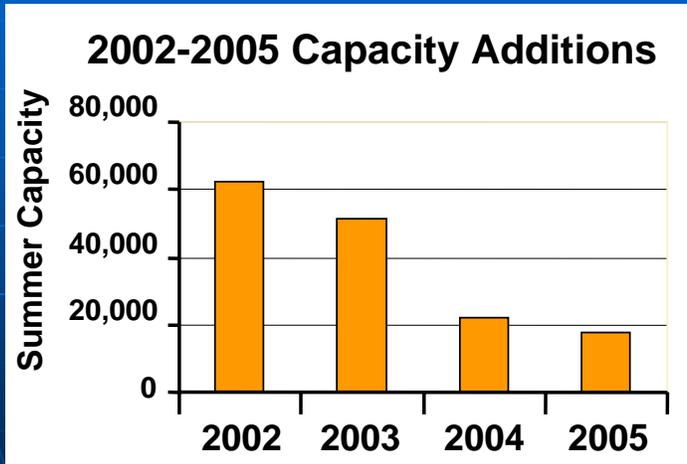


Source:
Edison
Electric
Institute

One reason for the expected continued strength in future gas prices may be the increasing demand for natural gas in electric generation. The Edison Electric Institute's data regarding U.S. generation over the year in 2005 is graphed here in blue and compared to the 5 year historic range shaded in yellow. With hot summer temperatures, we see that 2005 electric generation was often higher last year than in the previous 5 years. In addition, while overall electric generation was up, generation from natural gas grew even more. According to available full-year data from EIA for the 5 years ending in 2004, the overall increase in electric generation grew at an average of 1.5 percent per year while electric generation from natural gas increased at an average rate of 5.1 percent per year for the same period. Another summer of strong electric demand growth for natural gas, like last year, may be a factor in current futures prices.

This relationship between electric and gas markets is becoming increasingly important. Consequently, as we consider this important relationship and begin to look forward to next summer, I'd like to shift the focus a little, and review some recent information developed by staff looking at generation investment trends.

Generation Additions Declined Again in 2005



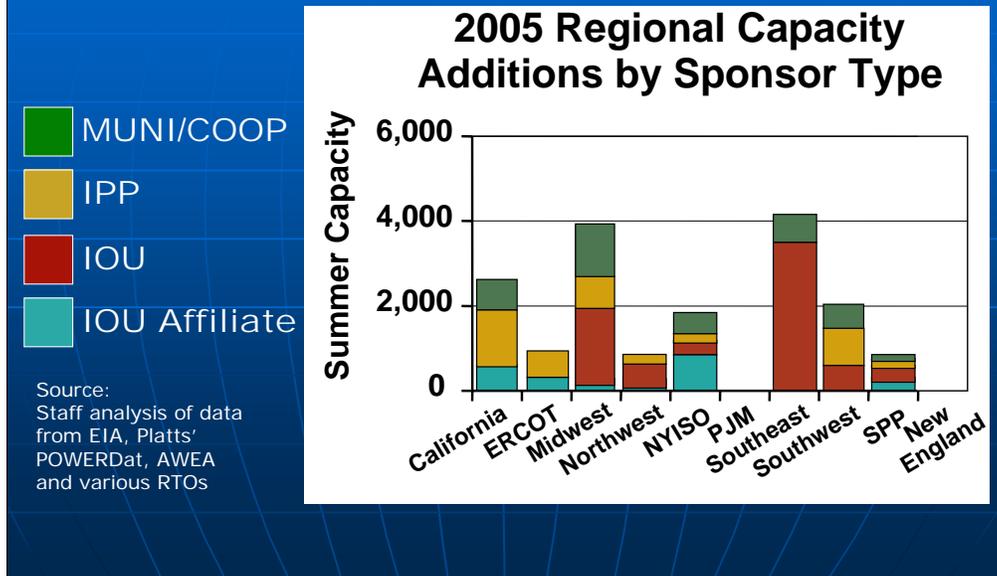
Source:
Staff analysis of
data from EIA,
Platts' POWERdat,
AWEA and various
ISOs

To develop these generation addition figures, staff used data from a variety of sources including EIA, Platts' POWERdat, the American Wind Energy Association, and the various RTOs and ISOs. Staff verified all the figures from the various sources in the assessment and eliminated any that it could not verify. As a result, estimates will differ. EIA reports 13 gigawatts (GW) of additions, less than the staff analysis. Platts reports more, about 19 GW. In addition, staff figures do not take account of retirements or repowerings. However, staff's methodology is consistent across the analysis presented.

According to our study, additions to U.S. generation capacity in 2005 totaled approximately 17 GW, down 25 percent from the prior year and down 75 percent from 2002. 2002 saw the most generation additions in U.S. history. So, to put 2005 additions into a larger context, though lower than the previous 5 years, 17 GW represented more generation added than in 14 of the previous 20 years. Current plans indicate that additions in 2006 are likely to be roughly half the 2005 level.

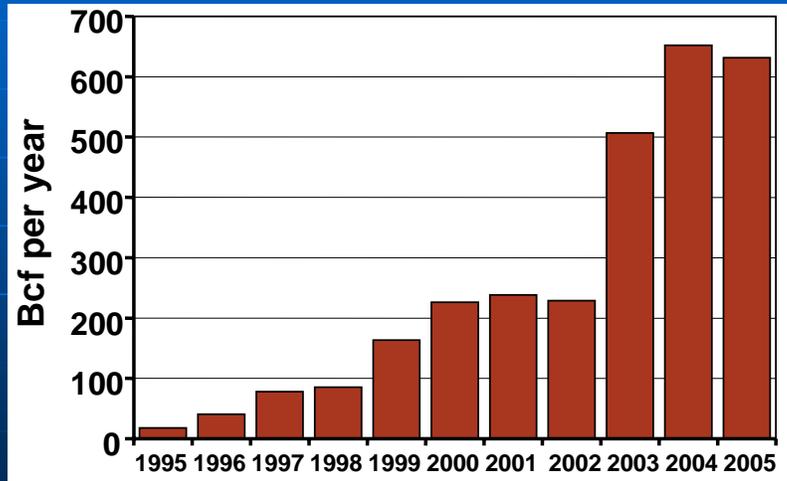
Several trends were interesting. The first is that the generation additions were slightly more diversified in 2005, with 84percent burning gas as opposed to 96 percent in 2004. Coal remained steady at 2percent, and wind increased significantly from 1percent in 2004 to 14 percent in 2005. The wind increases were certainly related to the extension of federal tax credits and the expansion of state fuel diversity initiatives. Clearly, gas is and likely will continue to be a dominant fuel for new generation for some time. Although there has been increased discussion of coal and nuclear generation in the recent past, the lead times for these investments are long, and generation using these fuels did not make big showings in 2005.

Generation Investment Dominated by Utilities



This graph shows both the geographic diversity and the ownership breakdown of generation investments. Let's start with geography. The biggest area for investment was in the Southeast, mainly in Florida, which faces some congestion. California and the Midwest not only saw relatively high levels of investment, but also showed substantial increases over 2004 levels, with California investment more than tripling and Midwest investment almost doubling. New England had no additions we could identify, and PJM's were small, mainly renewables. I should note that the staff analysis and PJM differ on the timing of one 750 megawatt plant. We counted it in 2004, as has EIA. PJM counts it in 2005. Overall, about one third of all additions appear to have been made in areas that are constrained and face transmission congestion, particularly California, Wisconsin and downstate New York. The breakdown in investors is also of interest. In total, municipals and cooperatives added a little less than 4 GW, just slightly less than in 2004. Investor-owned utilities, identified as IOUs on the graph, added 7 GW of the capacity in 2005, almost tripling their 2004 investments. Their affiliates added a little over 2 GW, a little more than a third of what they added in 2004. Finally, independent power producers, shown as IPPs on the graph, added more than 4 GW, down from over 7 GW in 2004. Geographically, there were differing patterns. In the Southwest, for example, virtually all generation added was by munis, coops and investor-owned utilities. The most investment by independents was in California, the Southwest, Texas (or ERCOT) and the Midwest. We expect generation additions to decline again in 2006 and an increasing proportion of development efforts to focus on baseload coal and nuclear as well in renewables. Regional trends in investment and trends in investor type are not so clear. With that, I'd like to turn it over to Jeff.

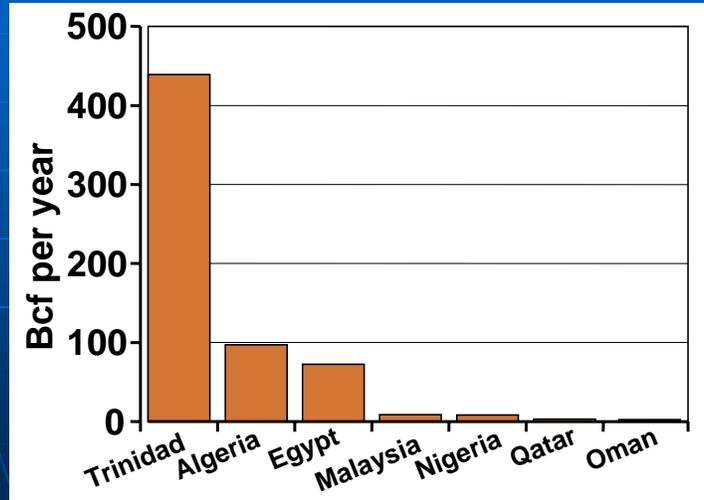
U.S. LNG Imports Decline Slightly



Source:
DOE/OFE,
EIA

At the last Commission meeting I gave a preliminary recap of US LNG activity in 2005. Since that time the Office of Fossil Energy at the Department of Energy has finalized the LNG information for 2005. DOE reports that during 2005 the United States imported 275 cargoes of LNG totaling 631.3 Bcf. This is a 3 percent reduction in LNG imports from 2004 levels. LNG supplied about 3 percent of the U.S. gas supply, assuming total 2005 demand of 22 Tcf. The weighted average price per Mmbtu for the imported LNG was \$7.82 which compares favorably with the Henry Hub price, which averaged \$9 per Mmbtu for 2005, according to the Energy Information Administration.

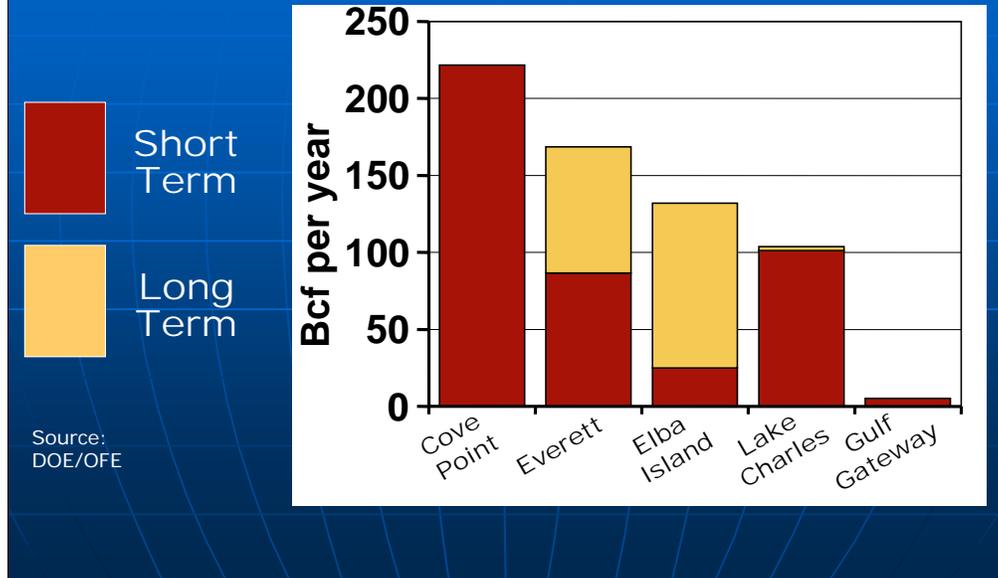
U.S. LNG Imports Dominated by Trinidad



Source:
DOE/OFE

About 70 percent, or almost 430 Bcf of LNG, came from Trinidad, our largest supplier. Approximately 62 Bcf originated in Algeria and nearly 50 Bcf was imported from Egypt. These three countries accounted for 86 percent of 2005 LNG imports to the U.S.

U.S. Imports Predominantly Short-term

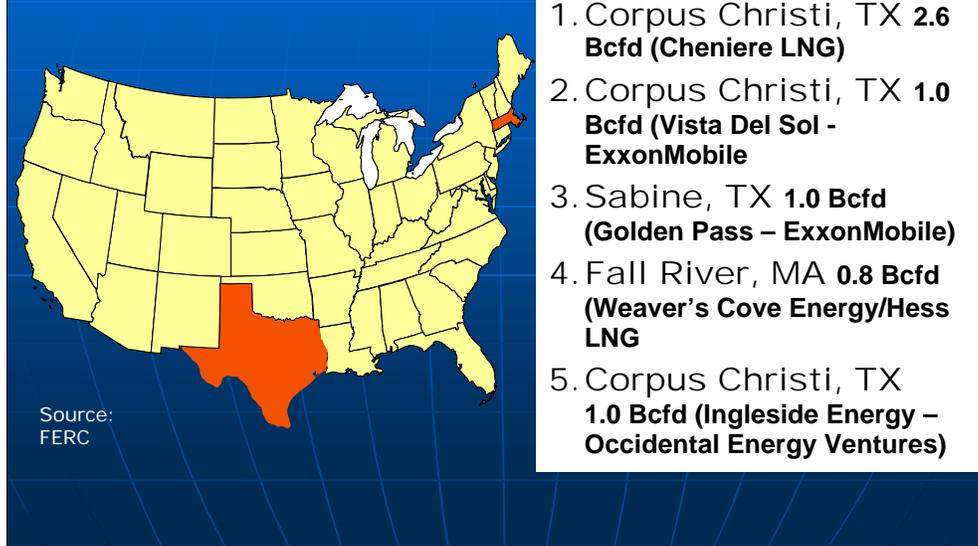


The busiest U.S. regasification terminal was the Cove Point facility in Maryland, which received 222 Bcf, or 35 percent of the total imported LNG. And, it should be noted, all of the volumes it received were under short-term authorization. The least active terminal was the offshore Gulf Gateway which, after opening in March 2005, received only two cargoes.

Let me explain that the Office of Fossil Energy at the Department of Energy approves LNG imports either on a long-term basis (greater than 2 years) or on a short-term basis. Short-term authorizations are blanket authorizations which do not require a contract to be provided. However, the length of the contract underlying the authorization – whether short or long-term – is not necessarily relevant to whether LNG shipments are required under the contract to be delivered to the United States. Just because a supplier has a long-term contract provides access to a terminal to import LNG does not mean they are necessarily committed to using that terminal if the economic value of the cargo is higher elsewhere. For example, in January, long-term contract holder BP diverted a cargo that originated in Trinidad to Japan. The cargo was initially destined for Cove Point but went to Japan because of a rumored \$13/MMBtu price from Kendai Electric – higher than prices available in the United States. Because of the mild weather and relatively lower prices in January that Steve just discussed, receipts of LNG in the United States reached their lowest monthly level since April 2003.

Nearly 70 percent of the LNG imports into the United States in 2005 were under DOE's short-term blanket authorization. For the last three months of 2005 – the period when the DOE began tracking spot deliveries – 27 percent of U.S. LNG imports were spot deliveries.

U.S. LNG Terminals Approved by FERC-2005



In 2005, the Commission authorized five LNG regasification terminals with a combined 6.4 Bcf per day of deliverability. Four of these terminals would be located in the State of Texas. Construction on 9.2 Bcf per day of deliverability is currently occurring at five sites – the first three sites listed on this slide as well as the Cameron LNG site in Louisiana and the Freeport site in Texas. On February 1st, service commenced at the expanded facilities at the existing Elba Island facility in Georgia. Besides substantially increasing its storage capacity, Elba Island's maximum sendout capability nearly doubled to over 1.2 Bcf per day. Elba Island's latest expansion proposal, which will increase its deliverability by another 1 Bcf per day is now in the pre-filing phase at the commission. To compliment this increase in LNG receiving capacity, the Commission has been taking actions on other gas projects necessary to support downstream delivery of the additional gas supply. In 2005, the Commission approved 20 major pipeline projects totaling 870 miles of pipe with an associated capacity of about 12.3 Bcf per day. 7.5 Bcf per day of this capacity is linked to facilities to take regasified LNG away from the approved terminals. The Commission also approved nine storage projects in 2005 with a total storage capacity of about 110 Bcf and daily deliverability of 3.2 Bcf. Four of those projects were in the gulf area, ostensibly to store regasified LNG. These four projects accounted for over half of the approved capacity and two-thirds of the daily deliverability. That concludes our presentation. Steve and I would be happy to answer any questions you may have.