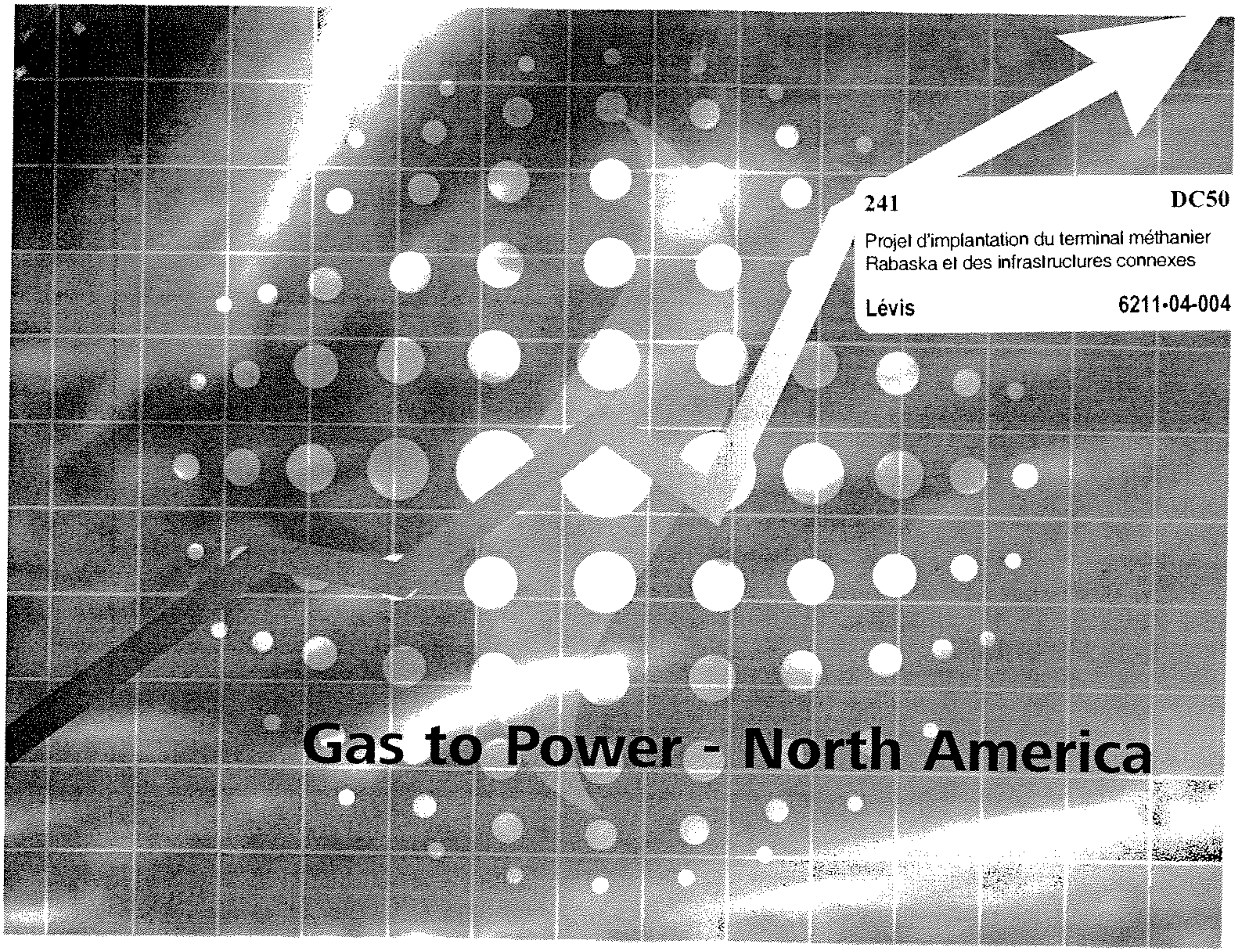

Gas to Power - North America

2006

75 years IGU

International Gas Union
Union Internationale de l'Industrie du Gaz

GAS TO POWER – NORTH AMERICA

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FOREWORD

The International Gas Union (IGU) is an international worldwide non-profit organization registered in Vevey, Switzerland, with the secretariat located in Hoersholm in Denmark. Founded in 1931, it currently has 85 members in 67 countries. The members of IGU are generally national associations of the gas industries or companies with assets in the gas industry.

The main objective of IGU is to promote the technical and economic progress of the gas industry worldwide mainly by facilitating the exchange of information of both a technological nature and of a more general, business-oriented nature.

To that end, IGU organizes the World Gas Conference, which takes place every three years. The programme towards the World Gas Conference is implemented by Working and Programme Committees, which study all aspects of the gas industry from the wellhead to the burner tip.

In preparation of the 2006 World Gas Conference, the IGU Dutch Presidency has launched three special projects: Gas to Power, Regulation and Sustainability. For all three projects, the aim is to engage governments, industry and other stakeholders in a dialogue on gas-related issues to achieve the best solutions for society at large.

The Gas to Power Project has been set up in view of the pivotal role that power is likely to play in the development of new gas markets and the realization that it will take enormous effort to achieve the projected growth. It aims at identifying possible obstacles and addressing them by inviting the governments and the power industry to discuss them jointly with the gas industry. Clearly, the Regulation Project is closely related to the Gas to Power Project.

With regards to the Gas to Power project, the IGU is carrying out surveys in the main regions around the world to assess the prospects and expectations for future gas-fired power generation and to identify potential obstacles that may negatively affect their realization. Where possible, it then organizes small regional workshops in an effort to foster the dialogue between the power industry, the gas suppliers and governments and address the issues surrounding the potential of gas to power uncovered in the survey. One such workshop was held in February 2005 in Houston, Texas. Taking the projections of potential demand, the workshop brought together leaders and decision makers from government and the gas and power industries who provided their perspectives on the issues surrounding the availability of future supplies, the competitiveness of new gas-fired generation vs. alternative fuels and other technologies, and how government policies may affect the choice of fuel for power generation.

For North America, IGU asked Terry Thorn from JKM Consulting to conduct the survey and prepare a paper describing the current North American energy environment, forecasts of natural gas demand, and the potential issues surrounding the continued use of natural gas in power plants. Based on feedback and findings from that workshop as well as an analysis of market events in 2005, updates have been prepared constantly. This report is current through April 2006 and includes the projections contained in the U.S. Energy Information Agency's Annual Energy Outlook 2006 released in February of this year as well as new production data for the onshore areas of the United States.

The IGU thanks Terry Thorn from JKM Consulting for his tireless efforts throughout the whole project period. And the IGU also would like to express its gratitude towards all workshop participants for their active contribution to understanding the future role of natural gas in North American power generation.

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Executive Summary

For a decade now power generation has driven natural gas demand in North America. Although electricity growth in the decades ahead is projected to increase in all sectors and will require significant additions of base-load generating capacity, today's high and volatile prices and concerns about supply are challenging the idea that natural gas will continue its dominant role as the fuel of choice for new power generation. Nonetheless, several recent studies continue to predict a strong preference for natural gas.

The projections of electricity and gas supply and demand contained in the International Energy Agency (IEA) *World Energy Outlook 2004* (*WEO2004*)[1] and the Energy Information Agency's (EIA) *Annual Energy Outlook 2005 and 2006 (AEO2005/AEO 2006)*[2] project a significant and growing role for natural gas in new power generation. Verified by a number of private studies which see natural gas barely increasing its total market share over the forecast period but nonetheless capturing 50-60% of all new power generation, gas demand was projected to increase to almost 30 trillion cubic feet (tcf) a year by 2030 compared to a little over 22 tcf in 2004. [3]

In February 2005, the American Gas Association released its study "Natural Gas Outlook to 2020."[4] The study contained three scenarios which described potential market conditions and the key policy variables that would impact natural gas markets. The expected scenario sees LNG import capacity increasing to 18 billion cubic feet (bcf) per day by 2020 and some lessening of restrictions on drilling in the lower 48. The study predicts that natural gas will fuel 40% of all new electricity generation during this period.

The common view in all these studies is that increases in LNG imports and new supplies from Canada, the Rocky Mountains, and non-conventional sources will keep prices down prior to 2010 and government policies will help facilitate these developments. Concerns about the environment and new regulations will further boost natural gas' competitive position as a fuel for power generation.

The Prize: 25% of the Largest Electricity Market in the World by 2025

EIA had projected that the total US electricity sales would increase at an average annual rate of 1.9% in the *AEO2005* reference case, from 3,481 billion kilowatt-hours in 2003 to 5,220 billion kilowatt-hours in 2025. With natural gas capturing 60% of all new generation, this rate of growth translates into a 4.4 tcf increase in gas used for generation from 2003 to 2025. IEA, in their 2005 study, shows a total North American electricity growth rate of 1.3% per year and projected that natural gas will account for 25% of all generation capacity by 2020, a 4.5 tcf increase in gas use for generation from 2002 to 2020.

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[1] International Energy Agency's *World Energy Outlook 2004*, released in Paris on October 26, 2004.
[2] Report #: DOE/EIA-0383(2005)
[3] IEA significantly revised upwards energy prices in their *World Energy Outlook 2005* released in November 2005. Despite these higher prices, IEA still expects world gas demand to double by 2030 with power production driving the increase. In the 2006 Annual Energy Outlook released in February 2006, EIA now projects gas consumption in 2025 will be 3.7 tcf lower than projected in the *AEO2005* reference case, mostly as a result of higher natural gas prices. The natural gas share of electricity generation (including generation in the end-use sectors) is significantly lower and projected to increase from 18% in 2004 to 22% around 2020, before falling to 17% in 2030 as coal increases its market share.
[4] www.gasfoundation.org/ResearchStudies/2020.htm

However, the dramatic energy events of 2005 have had a sobering affect on many of the forecasts. The *AEO2006* projection, of 1,070 billion kilowatt-hours of electricity generation from natural gas in 2025 is 24% lower than the AEO2005 projection of 1,406 billion kilowatt hours. Despite this downward revision, more than 60% of new capacity additions are still projected to be natural-gas-fired combined-cycle, combustion turbine, or distributed generation technologies.

Coal-fired power plants are expected to continue supplying most of the nation's electricity through 2025. In 2003, coal-fired plants (including utilities, independent power producers, and end-use combined heat and power) accounted for 51% (1,970 billion kilowatt-hours) of all electricity generation. Their output is projected to increase to 2,890 billion kilowatt-hours in 2025, while their share of total generation declines to 50% as a result of a rapid increase in natural-gas-fired generation. Natural gas is expected to have the largest increase in its share of total electricity generation is still expected to overtake nuclear power as the second-largest source of electricity production in North America.

Studies Find Comfort in Future Supplies, Price and the Competitive Position of Gas

The economics of almost all of this incremental power generation is based on natural gas prices being competitive with coal and other alternative fuels. Although today's high and volatile prices are challenging the assumption that natural gas will continue its dominant role in power generation, the IEA, EIA and other forecasts predict, that although coal will make a come-back after 2010, prices will be competitive enough for natural gas to capture the majority of all new power generation between now and 2025.[5]

The Price Forecasts:

- Recognizing that gas prices have soared since the end of the 1990's, the IEA Outlook expects North American gas prices to fall back to $3.80 million British thermal units (mmbtu)(2000 prices) by 2010 and steadily rise to $4.70 mmbtu by 2030.
- The average U.S. wellhead price for natural gas in the *AEO2006* reference case declines gradually from the current level as increased drilling brings on new supplies and new import sources become available. The average price falls to $4.46 per thousand cubic feet (mcf) in 2016 (2004 dollars), then rises gradually to more than $5.40 mcf in 2025 (equivalent to about $10mcf in nominal dollars) and more than $5.90 mcf in 2030. These prices are 30 to 60 cents an mcf higher than the 2005 forecast.
- EIA had predicted at the end of 2004 that the average Henry Hub price for 2005 will be $6.60 mmbtu. Prices for 2005 were $9.00.
- The AGA study forecasts that natural gas prices will remain in the $5 to $6 per mmbtu range for most of their study period with a nominal gas price forecast of $8.15 mmbtu in 2020.
- Five public and private studies predict a decline of gas prices between now and 2010 stabilizing in the $4.50 to $5.50 mmbtu range and gradually rising after 2010 to above $8.00 mmbtu by 2020 (nominal 2003 dollars).

These prices are low enough for gas to be competitive but high enough to support LNG imports and unconventional natural gas production.

[5] EIA rates the failure to expand unconventional production, followed by low LNG imports and no Alaskan gas as the top three threats to the expansion of gas-fired generation.

The Supply Outlook:

- The studies predict the opening of at least six new LNG terminals and the expansion of the existing terminals by 2010 and an increase in LNG supplies to 5.5 tcf by 2020.
- None of the studies saw new terminal capacity restricting future imports.
- The studies further assumed that there would be a considerable increase in Rocky Mountain Gas production and other frontier areas.
- Canadian exports will be flat to 2010, declining afterwards.

Gas' Competitiveness:

- Although at year-end 2004 118 new coal plants had been announced, because of long lead times to build plants, uncertainty about future environmental regulations and the inability to site plants near large market areas, natural gas plants will maintain an advantage in many markets.
- The consensus forecast is that coal use will grow 1% a year while coal prices will remain relatively flat during the forecast period due to increased mine efficiency and the increased use of western coal.
- Renewables will contribute 5% of the total generation capacity by 2025.
- Distributed generation will play no major role in power generation.
- Nuclear energy will not increase its contribution. No new plants will be constructed during the forecast period.

A Year of Discontent: High Oil and Gas Prices and A Record Hurricane Season Highlight the Fragility of the Resource Base and Cast Doubt on the Forecasts

In the course of completing the survey it was found that many of the assumptions contained in the studies were being challenged by some of the consumers and producers of electricity who are trying to sort out the economics of their future generation choices. The record summer demand, high prices, supply shortfalls and hurricanes Katrina and Rita which drove prices even higher, further magnified their concerns about the potential resource base and future natural gas prices. Natural gas had risen six fold on the New York Mercantile Exchange since September 2001 and touched a record $15.78 mmbtu in early December. Despite a 30%+ increase in the gas rig count over the past 24 months, gas supply continues to drift downward. Although prices plummeted on December 23 because of warmer temperatures and a promising storage report, the 2006 consensus for gas prices has moved in two years from $5.75 to $9.80 and $8.84 in 2007.[6] The average U.S. wellhead price for natural gas in the *AEO2006* reference case declines gradually from the current level as increased drilling brings on new supplies and new import sources become available. The average price falls to $4.46 mcf in 2016 (2004 dollars), then rises gradually to more than $5.40 mcf in 2025 (equivalent to about $10 mcf in nominal dollars) and more than $5.90 mcf in 2030.

Gas suppliers, while optimistic about the resource base, are concerned about future price volatility, government policies that restrict access to frontier supply areas, and the ability of the gas industry to build the infrastructure necessary to get these new supplies to market. Many of these same issues were raised by the North American workshop participants.

In summary, several critical areas will affect the ability of gas to capture new power markets and meet the volumes predicted in the various supply forecasts:

1) The greatest concern was price and its impact on gas' ability to compete with coal and other energy forms. There was disagreement as to what was the critical price point where

[6] EIA *Short-Term Energy Outlook*, January 10, 2006.

coal gained a definitive economic advantage. While there was a general optimism over LNG supplies, there was also disagreement over the price impact of new LNG imports. Some forecast a significant lowering of gas prices while others see more stability in prices but no negligible decrease in prices.

A likely scenario offered by producers is that the current high prices may briefly reverse as the record rig count produces temporary increases in US production. Post 2008, imports reduce prices to a point where higher marginal cost supplies, such as the deep water gulf, can't compete. The resulting baseline gas price of $5.00-$6.00 mmbtu would be high enough to support LNG and unconventional production but not so high that they would discourage gas use.

2) There was no agreement on the equilibrium price for gas as it relates to world gas markets or how gas prices will relate to oil prices.[7] Demand for electricity will keep pressure on gas prices based on the large residual need for natural gas as the existing gas plants are fully utilized. The real battle for market share will occur after 2010 as the need for incremental generation manifests itself.

3) The availability of new supplies was dependent largely on government polices, the second area of greatest concern. Policy and regulatory concerns covered the opening more of the frontier areas to drilling, the siting of new LNG facilities and new environmental regulations dealing with carbon emissions. With active federal intervention in the approval of new sites, LNG could eventually account for 10-15% of North American gas supplies.

4) However adequate terminal facilities for LNG, imports will not guarantee adequate supplies. Competition for LNG is intensifying as demand from all major regions is rising, while LNG supplies are lagging behind.

5) Coal will continued to be viewed as a secure domestic alternative to imports. The extent to which government policies subsidize coal use, either through direct subsidies (see 8 below) or the relaxation of environmental standards, may accelerate coal usage.

6) The loss of momentum for deregulating electricity markets will impact the already struggling merchant power sector. Wanting to avoid another Enron-type supply crisis, utility commissioners are focusing on "security of supply" and again supporting utility owned generation.

7) Utilities are revisiting their portfolio choices and seeking a broader fuel mix by including more renewables and coal. Some distributors are questioning outright the use of natural gas for power generation.

8) Technology was an issue only in the context of large government subsidies for clean coal technologies and other non-gas technologies. The recently passed energy bill contains strong incentives for the coal and nuclear energy and it is now likely the US will see a new nuclear plant in service by 2015. These new incentives and the lingering concerns

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[7] One school of thought has the Henry Hub and European indices setting prices as the Atlantic Basin market grows. These indices will reflect prices in the United Kingdom, U.S. and Spanish markets. The increased competition in the Atlantic basin was demonstrated when spot prices of Liquefied Natural Gas surged to record highs when Hurricane Katrina hit US natural gas output and LNG projects in Nigeria, Australia and Egypt suffered production problems. (An LNG cargo to be delivered into the United States was reported sold in late September at a record high price of $9.50 mmbtu). Others don't expect a complete disconnect between oil and gas. The market seems to be indicating 70% on a Btu basis. During the first 9 months Of 2005, Henry Hub gas has held a very steady relationship to oil, 72-75%.

about security of supply will boost clean coal and nuclear production above the levels forecasted in the studies.

It will take the remainder of this decade to work off the surplus of existing gas fired generation capacity. During this interim period, record high gas prices, concerns about supply, and a regulatory environment that puts generation choices back into the hands of the utilities who will seek more diversity in their generation portfolios will converge to challenge the conventional thinking about using natural gas for electricity generation. Add a relaxation of environmental emissions standards and you have a formula for an important but smaller role for gas-fired power generation.

GAS MARKETS TODAY
A CRISIS OF CONFIDENCE

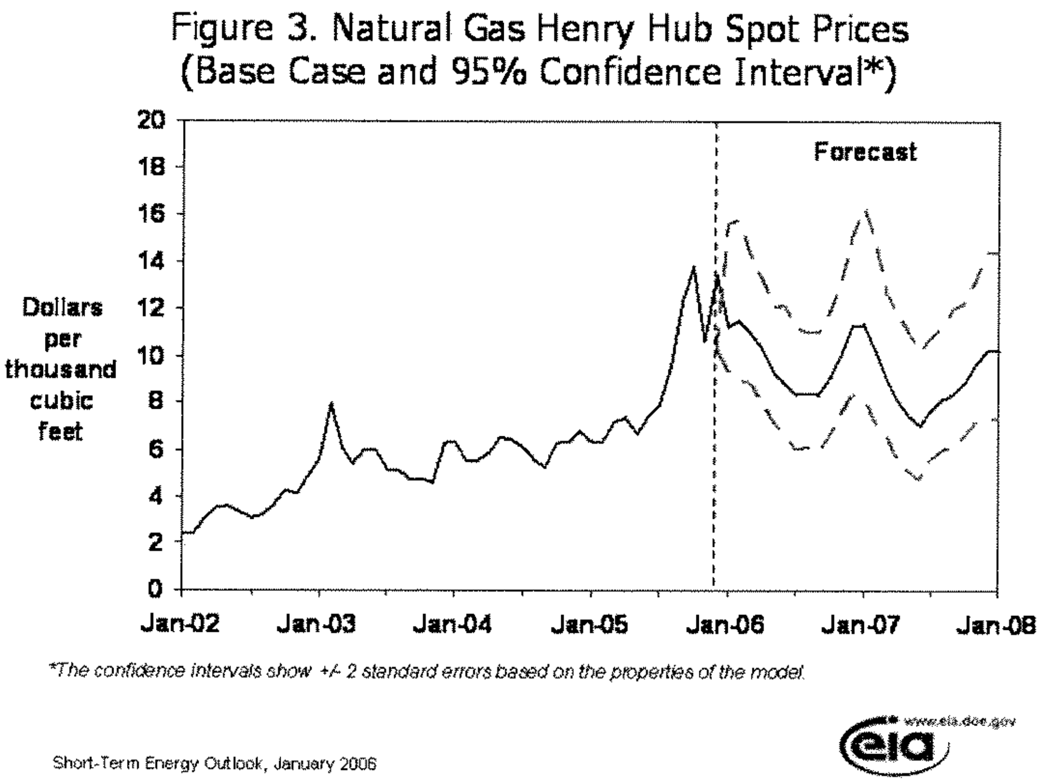
In most years, natural gas futures make the headlines during the winter months. But during the summer of 2005 the market experienced unprecedented high prices reaching levels never before seen for this time of year. The U.S as a whole set a new record for weekly electricity demand in July as hot summer weather increased demand for air conditioning. Natural gas delivered to industrial customers during that month was $7.67 per thousand cubic feet. The average price of natural gas at the Henry Hub in Louisiana for 2006 averaged $9.00 mmbtu. U.S. natural gas prices, which had doubled in less than 12 months prior to the hurricane and post-Katrina, almost tripled. The fuel for delivery in December at Henry Hub closed at $11.62 mmbtu on Nov. 23. Nymex natural gas rose to an all-time record of $15.78 mmbtu before easing back to $15.38 mmbtu in late 2005.

Hurricanes Katrina and Rita damaged, set adrift, or sunk 192 oil and natural gas drilling rigs and producing platforms, the most significant blow to the U.S. petroleum and natural gas industries in recent memory. Nearly 130 natural gas and oil pipelines were damaged. At the end of November 2005, 36 % of the natural gas output remained off line according to the federal Minerals Management Service (MMS). On January 9, 100 production platforms on federal leases in the Gulf of Mexico were still listed as evacuated in the wake of hurricanes last summer. The amount of gas production from federal leases still shut in January 2006 is 1.9 bcfd, or 18.6%, of the natural gas from those waters. Cumulative production lost since Aug. 26 totaled 581.7 Bcf of natural gas. That is equivalent to 15.9% of the natural gas produced annually from federal leases in the Gulf of Mexico.

But a winter that had started as a normal cold one turned surprisingly mild at year-end. On December 23 natural gas prices fell 40% from highs because of warmer temperatures and a promising storage report. According to NOAA, January 2006 was the warmest in 112 years- 8.5 degrees above normal resulting in a 15% drop in gas demand. February 2006 futures contracts settled for the first time since September 2005 at below $10. The price of natural gas trading for delivery in February closed below $9.00 and by April was at $7.00. The expected average for 2006 for Henry Hub spot prices of about $8 per thousand cubic feet (mcf), while down about $1 from the 2005 average, is still well above the pre-2005 historical maximum of about $6, reached in 2004 The consensus target for 2006 prices is over $8.00 mmbtu.

The Energy Department in their January report said natural gas consumers will still pay a record $1,000 on average for heating this winter, up 34.7% from last year. Although down from the 37.8% gain projected last month, it would still mark the biggest increase in five years. Natural gas heats more than half the homes in the United States. More than one-third of all U.S. industrial and manufacturing plants use natural gas to make products. And nearly 20% of the electricity generated in the United States is created by burning natural gas. The Energy Department predicts that heating costs for homes using natural gas or fuel oil could be 41% higher than last year.

Utility companies around the country have been so concerned about consumer outrage over huge natural gas bills this winter that they have launched public relations campaigns to convince customers that the companies are not to blame. The average U.S. monthly natural-gas spot price for January was 67% higher than the January 2005 average.[8]



Gas' Critical Role in the U.S.

The summer's record peak demand was an important reminder of the critical role that natural gas plays in electric generation. Since the start of 1999, more than 200,000 megawatts of gas-fired plant capacity has been built in North America representing 95% of all new generating capacity. The Northeast alone witnessed a 17% increase in gas-fired generation capacity from January 2003 to October 2004.

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[8] Sept. 15, 2005-- Schroders Investment Management North America Inc. issued a report predicting continued high natural gas prices in US markets beyond the end of the decade. The report's authors believe that 2005 estimates for US gas prices were understated. The report forecasts natural gas prices to be 12% ahead of the consensus estimates for 2006 and 25% ahead of current estimates for 2007 and 2008. The ConocoPhillips acquisition of the natural gas producer Burlington Resources for $35.6 billion will cap what has already been a big year for energy deals. It is clear that ConocoPhillips is betting that energy prices, especially for natural gas, will remain elevated for years to come; natural gas accounts for about 85 percent of Burlington's production, following its aggressive investments in nontraditional exploration methods in Texas and the Rocky Mountain states.

This dramatic building program has led to a surplus of power in the United States resulting in the cancellation or delay of new generation projects. The number of new megawatts of capacity expected to come on line in 2003 to 2004 has dropped by 3% and 60% respectively (Energy Venture Analysis, Inc).The rise in natural gas prices and excess capacity has also reduced the utilization rate of existing gas plants. According to the EIA, the need for most new capacity may now be delayed until after 2010. Nonetheless, full utilization of existing gas-fired capacity will put upward pressure on demand and prices.

Gas prices have trended upwards for the past five years

In the last five years, natural gas prices (prices herein are at Henry Hub unless specifically stated otherwise) have skyrocketed as growth in exports from Canada have slowed and domestic production has failed to keep up with demand. 2005 has been an industry nightmare. Although natural gas storage remains above the 5-year average, high world oil prices, continued strength in the economy, and limited prospects for growth in domestic natural gas production all support rising natural gas price projections.

Demand has flattened

Natural gas demand has slumped as high prices have hit the energy intensive industries hard. North American demand dropped 3.6% in 2003, 4.6% in the U.S. Reduced gas use by industry and power generation accounted for the entire drop in demand in 2003. The *WEO2004* reported that one fifth of the fertilizer capacity in the US and Canada has been shut down. The cost of nitrogen fertilizer has doubled to $500 per ton from $250 two years ago. Natural gas is combined with nitrogen from the air to make ammonia, the base for nitrogen fertilizers.[9]

The American Chemistry Council estimates that each $1/MMbtu increase in gas prices drives up the industry's costs of doing business by $4.2 billion. At Houston-based Huntsman Corp., the fourth-largest U.S. chemical maker, an increase in gas prices of $1 mmbtu boosts annual costs as much as $75 million. Over the past 12 years, the chemicals industry has lost 178,000 U.S. jobs, including 70,000 positions eliminated since mid-2002. The high cost of natural gas has been a contributing factor in decisions by companies to relocate manufacturing to countries like Trinidad and Tobago, and Saudi Arabia, where natural gas sells well below U.S. levels. IN 2004, 70 American chemical facilities were permanently closed, while another 40 plants were scheduled for closure in 2005. These closures have resulted in a drop of industry employment to below 880,000. Of the 120 new chemical facilities being constructed around the world, 50 are being built in China - while only one is being built in the United States. A report by Standard and Poor's notes that if dramatic price increases become the norm, the specter of deteriorating credit profiles could be a serious long term reality for major consumers of natural gas,

[9] Mid-winter storage reports in general have shown lower withdrawals than the weather- and hurricane-adjusted models have predicted. The implication is that a lot of demand destruction is ongoing. There may also be some onshore production response from the large amount of drilling activity but this is not as significant as demand destruction. Since most of the literal demand destruction problems (e.g., flooded refineries) have been corrected, the balance must be price-sensitive loads.

especially industries such as chemicals, plastics, packaging, and steel, as well as gas and electric utilities.[10]

Andrew N. Liveris, the chief executive of Dow Chemical, in Congressional testimony noted that energy and feedstocks represented 29% of costs in 2002. Today they are 50%. The high price of natural gas accounts for most of the rise. He noted that Dow had been planning to build a $4 billion chemical plant in Texas, and built it instead in Oman. Other issues - health care costs, litigation, and lack of tort reform - also cause Dow to locate elsewhere, but 80 percent of the reason is the availability and price of natural gas.

According to EIA, total U.S. demand for natural gas in 2005 is expected increase less than 1% due in large part to industrial users who cut back on usage by 7.5% because of the high prices. Demand for natural gas for production of electricity is expected to fall by 4.7 percent in 2006 because of the assumed return to normal summer weather, then increase by 2.4 percent in 2007 (*AEO2006*).[11]

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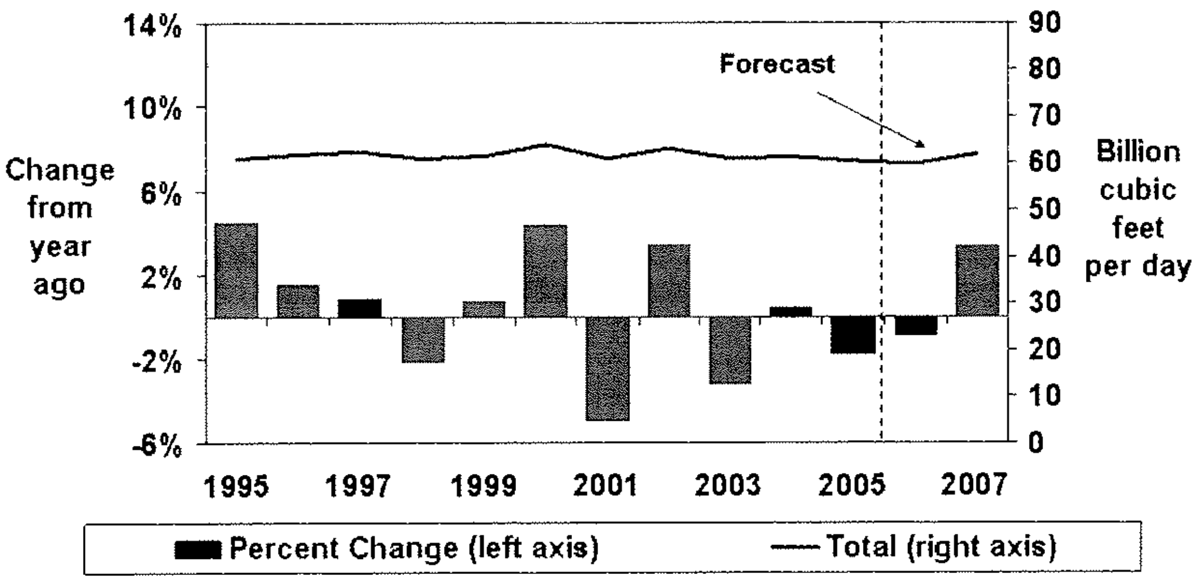
[10] Standard & Poor's Ratings Services, titled "Katrina and Rita Pressure Natural Gas Model; U.S. Infrastructure Vulnerability Exposed."

[11] Even at prices well below those only a few weeks ago, natural gas is still expensive, especially for manufacturers of such products as commodity petrochemicals and ammonia fertilizers. Many of these manufacturers have curtailed production recently in response to very high absolute and relative natural gas prices. In response to the price disparity between the U.S. and many international producing areas, considerable amounts of commodity chemical production capacity have left the U.S. and should continue to leave the U.S.

Figure 9. Total U.S. Natural Gas Consumption Growth

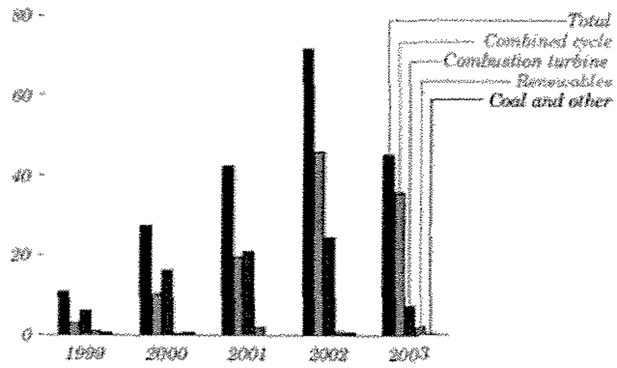


Short-Term Energy Outlook, April 2006

Gas power plants hit hard

The relative cost in North America of fuels is shifting significantly, with major implications for the cost of electricity.

Figure 69. Additions to electricity generating capacity, 1999-2003 (gigawatts)



AEO2005

The sharp rise of natural gas and oil and the belief that economic and political forces in play that may cause prices for these fuels to go higher is causing the power industry to reconsider its fuel choices. At a minimum, supply uncertainties and increased demand may have put a floor on premium fuels at, or near, current price levels. In effect, the power industry is reconsidering the fuels that were the solid stand- bys of the 1950s, 1960s, and 1970s- coal and nuclear energy.

Production stagnates despite record drilling

On the supply side, while higher natural gas wellhead prices have led to significant increases in drilling, the higher prices have not resulted in a significant increase in production. Instead, producers are drilling more and more wells just to maintain current levels of production. For 2004, drilling had returned to record levels[12] but North American natural gas productive capacity is not expected to grow meaningfully. In the early 1970s, the average US gas well produced nearly 160 million cubic feet a day (mmcfd), while today it is 46 mmcfd – a 70% drop.

United States existing gas productive capacity appears now to be in permanent decline. It reached it highest level in 21 years in 2001 at 19.6 tcf. Since then production has dropped despite the rapid increase in natural gas prices which, if the past were a guide, should instead be spurring increased output. In 2003, U.S natural gas production was 19.1 tcf, and in 2004 it declined again to 18.8 Tcf. Indicative of the problems with existing fields, New Mexico's natural gas production dropped by nearly 5% in 2004 and some in the industry say, in spite of anticipated depletion rates, the decrease was a significant one.[13]

[12] Natural gas rigs operating in the U.S. by July 29 totaled 1,221 and represented 86.5 percent of all rigs drilling, according to *Baker-Hughes*. In western Canada, a total of 554 rigs were operating in late July, which is up from 486 one year ago (+ 14.0 percent). The high utilization rate has continued into 2006.

[13] Domestic natural gas production in 2005 and 2006 is expected to remain near the 2004 level, despite a 16-percent annual average increase expected in natural gas-directed well completions. Preliminary EIA data through May and the projection for June yielded an apparent decrease in output of about 1% for the first half of 2005 compared to the same period in 2004. Domestic dry natural gas production in 2005 is

Even prospects for new finds in Western Canada won't be enough to balance the North American market. In response, the industry is scrambling to build, largely from scratch, a multibillion-dollar infrastructure to import liquefied natural gas from overseas.

There is renewed interest in other fuels

Because of the uncertain supply and price environment for natural gas, there has been a renewed interest in using other fuels for electricity generation. Coal is being promoted in several regions as a hedge against high gas prices and as a secure domestic fuel compared to LNG. Wind Power is being promoted as a way to reduce the current natural gas supply shortage. The American Wind Energy Association (AWEA) maintains that wind firms installed by the end of 2005 will save 500 mcfd of natural gas in 2006. Even nuclear energy is being promoted as environmental alternative to fossil fuels as a necessary element in solving the global warming problem. Clearly, against the back drop of volatile prices and declining supplies, greater fuel diversity is needed in the next wave of power generation to reduce reliance on natural gas.

THE DEMAND PROJECTIONS

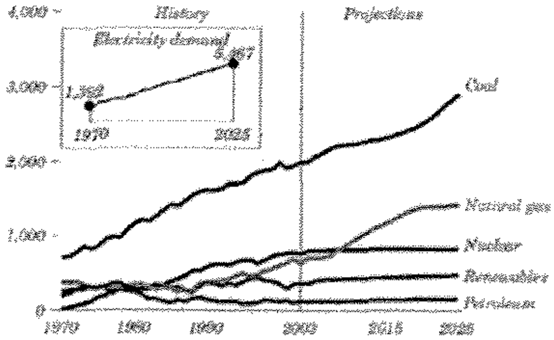
IEA and EIA (*AEO2005*) estimate that the total demand for natural gas increases at an average annual rate of 1.5 to 1.8% from 2003 to 2025, primarily as a result of increasing use for electricity generation.[14] The growth in demand for natural gas slows in the later years in the forecasts as rising natural gas prices lead to the construction of more coal-fired generation. EAEO 2006 forecasts electricity demand to increase annually through 2025, down from the 2.5% rate in AEO 2005.[15]

estimated to have declined by 3.1%, due mainly to the hurricane-induced infrastructure disruptions in the Gulf of Mexico. Dry gas production is projected to increase by 3.8% in 2006 and 1.1% in 2007 (*AEO2006*)

[14] U.S. demand for natural gas is expected to grow by 12% by 2012, according to a report released by Ziff Energy Group in October, from about 70 bcf to nearly 80 bcf. Most of that growth will result from demand from gas-fired electric power plants, which will grow from 24% of demand to about one-third by 2012.

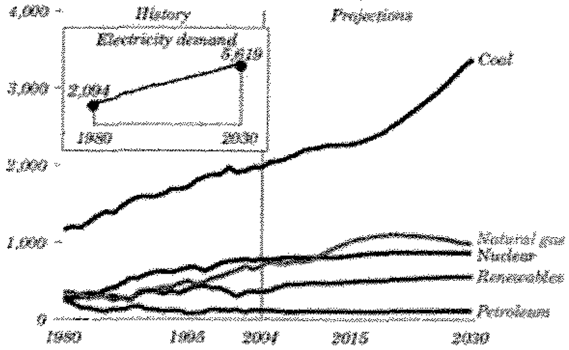
[15] Total consumption of natural gas in the *AEO2006* reference case is projected to increase from 22.4 tcf in 2004 to 27.0 tcf in 2025, 3.7 trillion cubic feet lower than projected in the AEO2005 reference case, mostly as a result of higher natural gas prices and an increased market share for coal.

Figure 5. Electricity generation by fuel, 1970-2025 (billion kilowatthours)



AEO2005

Figure 5. Electricity generation by fuel, 1980-2030 (billion kilowatthours)



AEO2006

Forecasters continue to believe that, despite today's high prices, natural gas will remain competitive in new power stations as the preferred fuel for high efficiency combined-cycle gas turbines. Its environmental advantages, lower construction costs and shorter lead time create economies of scale other fuels, especially coal, and can't match. No authoritative projection to date dramatically differs with this view.

Nonetheless, as the above chart illustrates, there is also considerable growth in coal-fired capacity although it is unclear in the EIA analysis how there can be such simultaneous strong growth in both coal and natural gas throughout this time period. Most likely the full utilization of current capacity and the completion of planned capacity fuels demand for gas between now and 2015 and accounts for most of the gas demand. Many of the proposed new gas-turbine-based combined-cycle projects have been canceled or significantly delayed. Most of those that have been built are not operating at planned capacity factors, and many of those that are operating favorably are displacing older, less-efficient gas-fired steam units, with a net decrease in fuel consumption per kilowatt/hour produced. So, even though electricity generated by natural gas has increased significantly, the fuel consumed to produce this electricity has only gone up modestly. EIA points out there were 410 gigawatts of gas fired generation in 2004 and they expect only 460 gigawatts by 2020 validating their forecast that the growth in gas will not be in a lot of new plants.

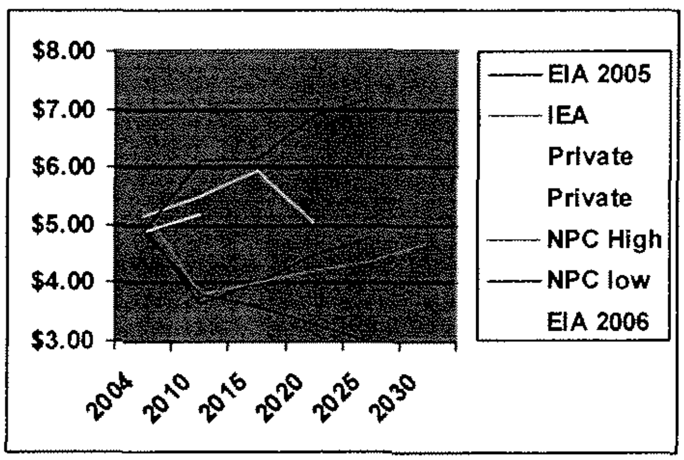
However, after 2015, new base-load coal plants capture more market share as natural gas prices begin to rise. During this entire period, coal prices remain relatively flat due to increased mine efficiency and the shift to cheaper western coal. Such price certainty, if it can be maintained, gives coal a longer-term competitive advantage. AEO 2006 predicts that lower electricity demand and higher natural gas prices will lead to significantly lower levels of gas consumption for electric generation during the forecast period.

THE PRICE OUTLOOK

The key factor in gas' ability to compete will be price. The average U.S. wellhead price for natural gas in the *AEO2006* reference case declines gradually from the current level as increased drilling brings on new supplies and new import sources become available. The average price falls to $4.46 mcf in 2016 (2004 dollars), then rises gradually to more than $5.40 mcf in 2025 (equivalent to about $10 per thousand cubic feet in nominal dollars) and more than $5.90 mcf in 2030. LNG imports, Alaskan natural gas production, and lower 48 production from unconventional sources are not expected to increase sufficiently to offset the impacts of resource depletion and increased demand. Wood Mackenzie estimates U.S. gas prices will average $6 mcf in 2006 and decline to $4.69 mcf in 2010 as new supply, such as liquefied natural gas, reaches the market.

The Canadian National Energy Board expects natural gas prices in Canada to remain high throughout 2006 and production to change little. Gas prices are expected to fluctuate in a btu-equivalent price range bounded by residual fuel oil and No. 2 heating oil, a range of $6.90 mmbtu to $10.34 mmbtu based on $50 oil.

The table below compares price forecasts from the EIA and IEA with the National Petroleum Council's 2004 report on natural gas and two private forecasters which do work for the natural gas utilities. With the exception of the NPC high case, gas price projections in 2005 were in the range of $3.50 mmbtu to $5.50 mmbtu over the forecast period. Producers and importers generally agreed with the price forecasts which they say will support LNG imports and unconventional production.

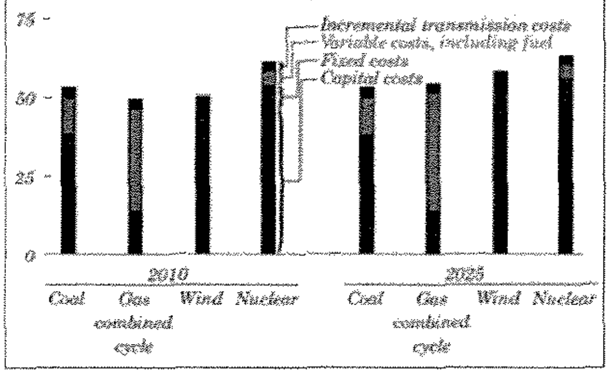


Summary of Approximate Prices 2003 Dollars

PRICE COMPETIVENESS

Not everyone agrees that these projected prices maintain a competitive advantage for natural gas. Integrated gas and electric distribution companies who have the option to look at both coal and natural gas for new base-load generation note that if LNG is economic at $3.50 mmbtu landed, coal is also be attractive at that price. Builders of coal-fired plants agree and point out that at $4.50 mmbtu a coal fired plant is not only attractive but an "economic opportunity." EIA maintains that improvements in efficiency gas turbines will offset higher gas prices. GE says that another 5% increase in efficiency is around the corner.

Figure 72. Levelized electricity costs for new plants, 2010 and 2025 (2002 mills per kilowatthour)



AEO 2005

Gas producers and many generators are concerned about whether or not the gas industry will be able to finance and provide the new pipeline and distribution infrastructure needed to deliver supplies to the growing electric markets from in frontier areas and remote from import facilities at competitive prices. These capital intensive projects will add to the delivered costs of natural gas and electric generation companies predict that coal will prevail where gas is priced at the margin such as in the western United States.

The price spread between gas, coal and nuclear reverses

The spread between natural gas and coal, more than $4 per mmbtu in 2003 and 2004 and higher today, translates to a difference of over 2.5 cents per kilowatt-hour. The spread between natural gas and nuclear fuel is about $5 per mmbtu-over 3 cents per kilowatt-hour. These are enormous cost advantages for the lower-cost fuels, particularly when one realizes that the average price of electricity in the U.S. today is just over 7.5 cents per kilowatt-hour. Nuclear and coal-fired power plants operate several times more intensively than natural gas and oil-fired plants, a fact that magnifies the economic and financial advantages of the low cost fuels. Nuclear plants have an average capacity factor of 85 %, and in some years 90%, while coal-fired units average capacity factor is more than 70%. In 2003, the average capacity factor for natural gas-fired generation was estimated to be 32%. In an unregulated market, where the natural gas is the marginal price of electricity, each megawatt of coal-fired generation would throw off about $160,000 a year in cash based on the differential fuel prices and average capacity factors. Each megawatt of nuclear capacity would generate about $250,000 a year in free cash based on current fuel price differences. Moreover, coal and nuclear plant nonfuel operating and maintenance costs are little or no higher than that for natural gas and petroleum plant on a per unit basis: the higher capacity factors result in these costs being spread over a larger sales base.

The sharp swing in fuel costs has increased the differential existing in average electricity price between regions and states. EIA data shows stark differences in electricity prices between 2003 and 2004. For example, New York (12.3 cents per kilowatt hour) and California (11.3 cents per kilowatt-hour) are vying for the most expensive electricity prices in the country, followed closely by the New England states (10.3 cents), New Jersey (8.9 cents), and Nevada (8.8 cents). All are heavily dependent on natural gas and petroleum to supply a large proportion of their electricity generation requirements. The average electricity rate in oil- and natural gas-dependent states was 9.15 cents per kilowatt-hour, versus 6.15 cents per kilowatt-hour for the rest of the country. This differential grew in 2003 and 2004 as the price of gas and oil continued to rise.

Over the long-term, dollars will increasingly be attracted to investing in generating technologies that use low-cost fuels. This no doubt will include new clean coal technologies, possibly super-critical pulverized coal units, and advanced nuclear reactors, some of which have already been certified by NRC. The rise in share price of utilities and power generators with large investments in coal and nuclear assets, and the bidding up in price of nuclear units going to auction, hint at the demise of the merchant power plant industry.

Federal and state rate regulators are moving in the direction of encouraging investment in low operating cost assets by developing large, liquid wholesale electricity markets by encouraging the formation of regional transmission organizations (RTO). In RTOs like PJM (which operates primarily in the Mid-Atlantic and Midwest regions), the effect has been to ramp up the output of solid fuel generating stations, displacing high operating cost natural gas and oil-fired units. The result is that those with well run, economically efficient generating plants tend to make significant returns. Over the long-term this should promote investment in similar facilities of an improved design.

CONTRACTS AND MARKET STRUCTURE

Merchant Gas-fired plants struggle in a time of high fuel prices and surplus capacity

The partial deregulation of the energy markets in the 1990s unleashed a construction boom fueled by freely available financing from the capital markets. Most of the new capacity was gas-fired, which was justified by expectations of low gas prices and gas plants' environmental advantages foreseeable future. At the time, natural gas prices were in the range of $2 - $3 mmbtu. Merchant builders made a fundamental error in the forecast for natural gas prices. The industry overbuilt and power prices subsequently fell.

At the same time the price of natural gas rose above $4.50 mmbtu squeezing the merchant energy sector.

The merchant electricity sector is likely to experience several more difficult years before returning to long-term financial health. The pressure on energy companies generally has been and remains intense- close to 200 were put on "credit watch negative" in 2002 alone. According to Standard & Poor's, downgrades in the merchant generation and trading sectors have slowed down by year-end 2004 but at the same time they have outpaced upgrades. Calpine Corp., one of the nation's largest wholesalers of electricity which operates 92 plants in the U.S. and Canada with a total capacity of 26,500 megawatts is struggling to repay $22 billion in debt and in December 2005 filed for bankruptcy. Power producers Mirant Corp., NRG Energy and National Energy & Gas Transmission have already sought bankruptcy.

Growth in asset sales at high discounts is not a reflection of a turnaround, but rather of continued weakness in US power markets, which is attracting new buyers looking for discounts, particularly financial buyers with lots of capital. Struggling to survive under a mountain of debt taken on during the boom that added more than 200,000 megawatts of generating capacity, those merchants have put many of those plants up for sale at a fraction of their construction costs. Debt refinancings have bought time for beleaguered energy merchants, but total debt burdens remain largely intact for most companies, and capital structures do not support investment grade ratings. Prices seemed to have bottomed out in 2005.

In October 2005, power supplier NRG Energy Inc. agreed to buy a portfolio of power plants in Texas owned by Texas Genco LLC. NRG paid six times the price paid for these same facilities just two years ago. The rapid appreciation was due to the high price of natural gas and the fact that half of the portfolio of plants consisted of coal and nuclear power plants which have lower operating costs but in Texas can sell electricity at the marginal price.

The $11 billion acquisition of Baltimore-based Constellation Energy Group Inc. announced yesterday by FPL Group Inc. would create one of the country's largest electric power companies and continue a trend toward industry consolidation. The Constellation deal would create a company with a market capitalization of about $28 billion, annual revenue of $27 billion and $57 billion in assets, the companies said. Analysts say FPL and Constellation fit well together. Constellation derives most of its revenue from its expanding unregulated power operations, while FPL earns most of its money from its growing utility business, which has more than 4 million customers. The combined operation would provide better potential for growth and reduce financial risk.

The unregulated merchant business model has not changed much and no blueprint has yet to emerge to make those power sales and trades any less risky. For the foreseeable future the industry will continue to undergo extensive restructuring efforts designed to cut costs, shed non-core or risky assets and reduce leverage and production costs for distressed gas-fired plants. These efforts will keep existing plants competitive but the competitiveness of new merchant plants which will have fully allocated costs is being questioned by the electric utilities. Utilities warn that it would be a mistake to make judgments about future generation developments based on what is running today.

Utilities, wary of the notoriously volatile electricity markets, are pulling back from the unregulated wholesale trade by expanding their own power plant portfolios to meet demand. The trend, which is also driven by state regulators' fears of California-style power shortages seen in 2000-2001 and their desire to have "guaranteed capacity," is a further blow to the hard-hit merchant power sector whose future heavily depends on a recovery in wholesale power markets. Oregon's Portland General Electric has sought state approval to build a new power plant despite receiving more than 100 bids to supply it with electricity, and Cincinnati-based Cinergy Corp. moved to transfer two power plants from its merchant unit to its regulated PSI Energy arm in Indiana. The Federal Energy Regulatory Commission agreed to Cinergy's power plant transfer and said it would allow Edison International's Southern California Edison to buy a power plant to supply its regulated business.

In the last ten years, the ability to hedge power sales margins (i.e. long term gas price and power price contracts) has almost disappeared and is beginning to affect the choice of power generation and fuel. Merchant operators argue that this is a short term phenomenon and that the future is bright for the merchant plant builder. Yet merchant builders today are seeking contracts that pass through fuel cost risk and some are even offering to "rent" their facilities asking power buyers to take on both the supply and off-take risk. The only operator risk would prudence and operational. Yet it is unlikely that neither equity investors nor lenders will finance new plants without at least 10 year purchase power agreements.

Is there a future for merchant plants?

These contracting practices have caused some utilities to predict that the day of pure merchant plant is over and that in the future large base-load plants will be built by utilities with a portion of the output reserved for spot sales. Price risks are easier to manage within the cost of service approach with its guaranteed cash flow and cost recovery. Why take all the supply and price risks from a merchant seller when you can build a rate based plant and have better certainty of recovering these costs. This shift in thinking about new generation puts power development in the hands of the very people who have the capital and time to build coal plants.

Others say that the merchant business of the future will be restricted to a portfolio plants near demand centers with PPAs that are not plant specific. You would sell from integrated system, not a single resource and have multiple fuel options. Under a high gas price scenario, new gas plants may be relegated to peaking purposes.

For now, absent another wave of federal market reform, merchant plants are now at the mercy of the state regulators.

Do electric transmission issues favor gas-fired plants?

While price developments may favor coal in the long term, a big issue and one of the concerns expressed by coal plant developers is the lack of adequate transmission capacity for moving electricity long distances. Reliability and congestion are issues that have been a struggle for utility managers and regulators across the West for more than a decade, as they have watched transmission line construction fail to keep pace with electricity demand. Transmission investment actually declined for 23 years from 1975 to 1998, according to FERC figures. Over that period, demand more than doubled, resulting in a significant decrease in transmission capacity. Investment has been up and down since, but still trails well behind demand, say regulators.

The Federal Energy Regulatory Commission (FERC) maintains that the cost of moving electricity across multiple distribution territories is too high and makes long-distance electric transmission uneconomic. As part of their "standard market design" effort, the FERC is trying to transfer oversight for the transmission to the FERC from the states by organizing the transmission systems of several hundred utilities into regional RTOs. They are meeting stiff resistance at the state level and resolution is years away.

FERC had ordered the development of a regional transmission organization in the west, but the effort was abandoned by the Bonneville Power Administration and large investor-owned utilities after the Western energy crisis of 2001 — when rates skyrocketed because drought reduced hydroelectricity generation, deregulation failed in California and Enron Corp manipulated the market. Following the energy crisis when it was apparent there was illegal manipulation of the interstate transmission system and illegal sales of power across high voltage power lines, FERC said there had to be a better system for handling bulk transmission of power

Part of this debate is the issue of who pays for and controls new transmission capacity. Utility managers and regulators say those questions need to be answered before demand outstrips supply to some of the most quickly growing U.S. regions. The Energy Policy Act of 2005 directed FERC to develop incentive-based rates for interstate power transmission. On Nov. 17, 2005, the FERC, in an effort to provide the regulatory certainty needed to reassure utilities and investors, proposed transmission pricing reforms.

The infrastructure to mine, deliver, use and dispose of residues of coal must also be built. Railroad capacity is at maximum capacity allowing railroads to capture a portion of higher generation prices.

Transmission capacity is also an issue for developers of renewable energy whose facilities aren't large enough to underwrite substantial transmission upgrades. Some are looking to "piggy-back" on the construction of large base-load coal plants as a way to gain access to new capacity. They see base-load coal plants as having the best financial capability to underwrite large investments in new transmission capacity.

High gas prices hit distributed generation hard

Distributed generation will basically follow the CHP market. In the U.S., generation is expected to double from 1998 by 2010 to 92 gigawatts. This represents great growth but still small in absolute numbers. Although DG uses mostly natural gas, the volumes will be relatively small. It's real cost advantage comes with cogeneration, not as peaking plants.

When gas prices rise the CHP is in trouble as one buys retail gas and sells wholesale electricity. To the extent distributed generation is used by utilities to hedge upgrade on transmission and distribution it will follow the central distribution model. When it is used as a back up the energy use is small relative to the capital cost, i.e., it is used only at peak times or during blackouts.

NATURAL GAS SUPPLIES

Concerns about natural gas production are shared by all segments of the industry. Natural gas production has not grown fast enough to meet historic demand and the requirements for new power generation as lower 48 production has declined over the past two years and imports from Canada have fallen from their peak in 2002. While the number of drilling rigs has risen to a three-year high, it has not resulted in higher production. According to Baker Hughes Inc., an oilfield services firm, the number of rigs drilling for natural gas in the United States in January 2006 is 1,224, just below the record set in September 2005. This number of rigs is 17% greater than a year ago and 23 per cent higher than the five-year average for this time of year. Rigs currently are fully utilized and under additional stress, and oil field goods, services, and people are in high demand and short supply. Some sectors are exhibiting hyperinflation of costs—as much as 30%.

The U.S. Energy Information Administration estimated in November 2005 that natural gas production for the year will decline by 4.2%, due in large part to the major disruptions to infrastructure in the Gulf of Mexico from the hurricanes, and then increase by 4.7% in 2006.[16] A fine balance exists between a decline in production from old wells and the annual production replacement rate from new wells on stream. More than 3.5 bcfd of new productive capacity must be added each year to replace natural decline. In 2004, U.S. gas supplies decreased by 1.2%,

The EIA is confident about future supplies

According to EIA, the supply gap will be filled with new gas supplies from Alaska and Canada, increased production of non-conventional natural gas supplies such as coal-bed methane, more aggressive exploration in frontier areas, and increased imports of liquefied natural gas. Lower 48 offshore production is projected to increase in the near term because of the expected development of some large deepwater fields but after 2014, offshore production is projected to decline. In the later years of AEO 2006 reference case,

[16]In April 2006, the FERC estimated that absent the hurricanes, 2005 production would have been up 2.7%. FERC points to production increases in several basins: FT. Worth- +17%, Uinta Piceance- +11%, Owalla- +10%, Wind River- +6%.

GAS TO POWER – NORTH AMERICA

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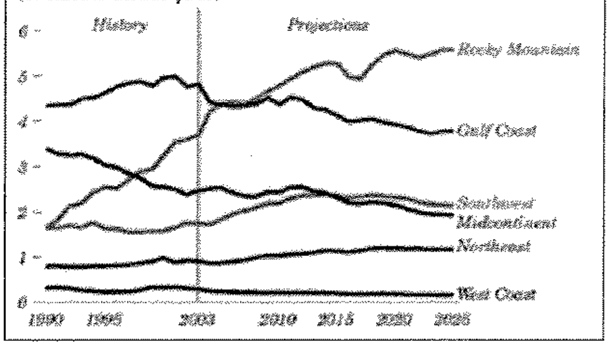
onshore production grows strongly. Supply balance is maintained through increased LNG imports. Their 2006 forecast assumes that at least four new LNG terminals will be built[17]; the Alaskan Gas Pipeline is in service by 2015 due to Congressional action, and the development of non traditional gas supplies have increased by over 30% in 2025. The Interstate Oil and Gas Compact Commission estimates that the Appalachian and Illinois basins may contain 79-96 tcf of gas in coal beds, Devonian shales and tight sands.

Figure 84. Lower 48 onshore natural gas production by supply region, 1990-2025 (trillion cubic feet)



AEO2005

As US natural gas depletion rates accelerate, the industry is seeking to produce gas from plentiful unconventional reservoirs: coals, shales, and tight sands, all of which require more stimulation technology. The largest increase in lower 48 onshore natural gas production is projected to come from the Rocky Mountain region. Last year, energy companies spent $10.7 billion in acquisitions and development in what geologists call the Greater Rocky Mountain Region (GRMR) which consists of The five core mountain states—Montana, Wyoming, New Mexico, Colorado and Utah. Six years ago, 1,639 such permits on federal land were approved. Last year, the administration granted more than three times that number, 6,052. Kathleen Clarke, director of the Interior Department's Bureau of Land Management (BLM) has noted that the agency expects to receive 9,200 new drilling permit applications in 2006. The agency said it anticipates another 10,000 permit applications in 2007.

The value of Colorado's energy production alone hit a record $8 billion in 2004. Geologists call the GRMR, which has 165 trillion-260 Tcf of natural gas, "the Persian Gulf of gas". According to Michael Farina of Cambridge Energy Research Associates (CERA), the GRMR currently produces 9% of America's natural gas; that figure could double in the next 20 years. The gas boom is being driven by technology and higher prices, not new finds. For example, the Jonah gas field in western Wyoming was discovered in 1975, and a single well was drilled that generated 300,000 cubic feet per day. But in 1993 new advances in drilling and geophysics uncovered a field with as much as 5 Tcf. Wyoming. It currently produces a third of the GRMR's gas, and is the home of

[17] AEO 2006 calls for four new terminals: Mexico Baja, the Gulf Coast, and two in eastern Canada. All of these terminals can be expanded by over 1bcfd.

both the Jonah field and a promising coal-bed methane development in the Powder River Basin.

Canada will no longer be the swing supplier for the U.S.

The latest assessment of Canada's National Energy Board (NEB) states that it is unlikely that future production from Canada will be able to increase imports to the United States and that Canadian gas production is likely to remain relatively flat through 2010. The NEB expects natural gas prices in Canada to remain high through 2006 and production to change little. NEB expects minimal change in average annual Canadian gas deliverability—to 16.87 bcfd by 2006 from 16.71 bcfd in 2004.[18] *AEO2006* projects a continued decline in net pipeline imports, to 1.2 tcf in 2030, as a result of depletion effects and growing domestic demand in Canada.

At the end of 2005, the Canadian Association of Petroleum Producers (CAPP) published estimates for 2004 that showed another decline in Canada's natural gas reserves. For 2004, CAPP estimated that only 99.5% of production was replaced, resulting in natural gas reserves declining year-over-year. Except for British Columbia's performance (a relatively small 16% share of reserves compared to Alberta's 75%), reserves would not have stayed flat. BC's relatively small gas reserves will have to take on a disproportionately heavier share of the replacement workload over time. There will soon come a time when Alberta's declines overwhelm B.C.'s additions.

Pessimism about Alberta production was challenged in a recent joint report from the NEB and the Alberta Energy and Utilities Board (AEUB). They estimated the amount of recoverable conventional natural gas from Alberta as 7% larger than the 2004 estimate from the NEB and 12% more than the last estimate by AEUB. The key reason for the increase is enhanced knowledge of the territory gained as a result of increased drilling since 1992. Of the estimated 223 tcf in the base case, only 62 tcf or 28% remains undiscovered. This estimate reflects only resources in known geologic plays.

Canadian Demand Skyrockets

Canada will also consume more gas natural gas and is projected to have the highest gas demand growth in the region 2004-2010 due to Kyoto Treaty commitments and oil shale production. Power generation also is driving gas demand. Ontario is working to remove 7,500 megawatts of coal-fired capacity from its power grid by 2009. Earlier this year Ontario's government approved plans to build two natural-gas plants worth at least C$869 million ($702 million) to increase its power supply as the province closes coal plants.

Given the recent rise in energy prices, a number of oil sands projects have become economically feasible despite significantly higher costs for natural gas, labor, steel and heavy equipment. During 2004, production from the oil sands was over 1 million barrels per day and is expected to nearly triple to 2.7 million barrels per day by 2015. There is an estimated 174 billion barrels of oil contained within the oil sands making Canada the

[18] NEB, "Short-term Outlook for Natural Gas and Natural Gas Liquids to 2006".

second largest country in terms of global proven crude oil reserves. It typically takes two tons of oil sands to produce one barrel of crude, which is 42 gallons. The companies move about 1 million tons of earth a day. The oil sands are buried under an area about the size of New York State.

Oil sands projects used 72 mmcfd in 2004, and are projected to consume 1.01 bcfd by the fourth quarter of 2006. 1.300 to 2100 cubic feet of natural gas are used for each barrel of crude produced. Peter Tertzakian of ARC Financial, a Canadian investment firm, estimates that investment in tar sands will leap to C$7 billion ($5.95 billion) this year, up from C$4.2 billion in 2000. More impressive is the tidal wave to come. High oil prices have prompted a flurry of investment in new projects and expansion efforts in tar sands that will, he estimates, add up to a whopping C$70 billion in coming years. Production is expected to triple to 3 million barrels a day by 2020. The industry spent C$28 billion on developing the oil sands from 1996 to 2003.

Net exports of natural gas from Canada are projected to peak at 3.7 tcf in 2010, then decline gradually to 2.6 tcf in 2025. EIA sees the decline coming sooner. While potential exists for new production from coal bed methane in the Western Canada Sedimentary Basin and deep tight gas deposits in northeast BC and the Alberta foothills, producers operating in those areas maintain that there is tremendous uncertainty associated with the timing, cost and potential production levels.

Hope for Alaskan Gas

There are two proposals competing for workers and capital to build a pipeline that would deliver natural gas from the Alaskan North Slope to the lower-48 states. Mid-American is proposing a route, as are Conoco-Phillips, BP, and Exxon, the three major North Slope producers. In addition to permitting requirements, there are disagreements as to how the projects should be financed, whether subsidies are needed, native groups in Canada have not yet given access rights, environmentalists are concerned about caribou and the permafrost, the pipeline companies face a mountain of regulatory red tape and promised lawsuits and how to connect the Alaskan pipeline to natural gas supplies that would be produced from Canada's McKenzie River delta area. Pipeline planners also want to be able to tap into potential natural gas supplies in Alaska's Arctic National Wildlife Refuge should approval be given to explore and develop its energy resources.

Of the two lines, the Alaska Gas Pipeline is the giant. Its most likely route would stretch 1,700 miles from Alaska's Prudhoe Bay to Canada's Alberta province. The line would cost $20 billion and take a decade to build, but the project has picked up momentum under the urging of Alaska Gov. Frank Murkowski and $18 billion in loan guarantees approved last year by Congress.

In October 2005, Alaska proposed terms for BP Plc and its partners to build the $20 billion natural gas pipeline to supply the lower 48 U.S. states. The proposal to the oil companies would provide Alaskans with a fair share of the line's revenue give other explorers access to it and make the state a part owner. The U.S. Congress has already passed the Alaska Natural Gas Pipeline Act, with $18 billion in federal loan guarantees for the project.

The second line, the Mackenzie Valley Pipeline, would start 250 miles east of the Alaska line, on Canada's portion of the Beaufort Sea. It would cross 800 miles of spruce and pine forests along the Mackenzie River -- one of the worlds longest with no bridge or dam. This all-Canada route would cost $6 billion and is predicted to take three years to complete once construction begins.

An antitrust lawsuit filed against Exxon Mobil Corp. and BP PLC on December 19, 2005 claims the two oil giants are restricting the nation's supply of natural gas and keeping prices at record highs. The lawsuit, filed in the U.S. District Court in Fairbanks, says the two companies acted together to eliminate competition for the exploration, development and marketing of natural gas from Alaska's North Slope to U.S. markets. The federal lawsuit arose from the producers' refusal to sell supplies of natural gas to the port authority, which wants to build a pipeline from the North Slope to Valdez. From there, the gas would be liquefied and shipped by tanker to the West Coast.

The Mackenzie Valley pipeline, which includes partners Imperial Oil, Shell Canada, ConocoPhillips and the Aboriginal Pipeline Group, has been stalled due to land access issues with native groups in Canada. Four reserves of Indians -- known as First Nations here -- are involved in negotiations to permit the Mackenzie line to cross their land. The four oil companies behind the project have agreed to give First Nations a one-third share of the line, and the federal government in July offered $425 million for native social programs as an incentive. But the bands are split over the proposal.

At a cost of some C$7 billion (US$5.6 billion), the Mackenzie line could by 2010-11 bring up to 1.9 bcfd of much needed arctic gas to Canada to fuel steadily rising demand. The larger Alaska Highway Pipeline, has also stalled as Exxon, BP and ConocoPhillips seek fiscal terms with the state of Alaska and regulatory clarity from the Canadian government. This system could tap as much as 6 bcfd of gas from the Alaska North Slope by 2012 at a cost of $15-20 billion. Stranded natural gas reserves on the Alaskan North Slope and in the Canadian arctic could total more than 40 tcf, according to analyst estimates.

Despite the optimistic forecasts, the producers are concerned

Gas producers express two major concerns about their ability to increase domestic production. The first is the willingness of the American public to support opening new drilling areas and eradicating environmental restrictions and other impediments to production in the offshore, Alaska and the lower 48 states, including the Rocky Mountains. Even Montana, environmental concerns have dictated a slower approach to Coal Bed Methane (CBM) development. The gas is produced when water that traps it in the coal seam is pumped to the surface, reducing the pressure and releasing the gas. Some ranchers and environmentalists worry that widespread CBM development could lower aquifers, degrade water quality in rivers and harm soils because of salts in the water that can remain in the soil. Environmentalists have filed a number of lawsuits over CBM development in Montana.

Environmentalists remain strongly opposed to opening areas such as ANWR and note that 88% of technically recoverable gas reserves on federal land are already available for leasing. The balance of 12% is in national park ands and other protected areas. They argue that legislation isn't needed and point to the fact that the Bureau of Land Management recently proposed an astonishing 70,000 new oil and gas wells for the Powder River Basin in Wyoming and Montana alone.

Richard Watson, senior physical scientist of the Fluid Minerals Group of the US Bureau of Land Management, cited a recent examination of access to federal lands in the Montana Thrust Belt and Powder River, Green River, Piceance, and San Juan basins in the Rocky Mountains.

"On a surface acreage perspective, it appears that only 39% of those federal lands are available for leasing under standard lease terms, 25% available with additional restrictions, and 36% totally unavailable," Watson said. "However, if you look at the oil and the gas resource volumes, 57% of the oil and 62% of the natural gas is available under standard lease terms and only 16% of the oil and 12% of the natural gas is completely unavailable."

The second concern involves the construction of the Alaskan Natural Gas Pipeline which may require major subsidies if it is to come online by 2016. North Slope producers, however, have said it could take up to 10 years to design, permit and build the main gas line, which would stretch more than 2,000 miles to Alberta. There, it could connect with existing lines for distribution across North America. It could take at least a couple of years just for steel mills to roll the proposed diameter pipe of 52 inches -- even larger than the trans-Alaska oil pipeline, with thicker walls to hold the gas pressurized to 2,500 pounds per square inch.

The National Commission on Energy Policy 2004 report noted that support for the pipeline in the form of loan guarantees, accelerated depreciation and tax credits was included in legislation passed by Congress at the end of 2004. But the Commission believes that additional incentives are likely to be necessary given the high costs, lengthy construction period, uncertainty about future gas prices and other siting and financing hurdles associated with the project.

LNG IMPORTS

According to EIA and IEA, LNG imports will rise dramatically

Presently LNG imports account for about 3% of total U.S. supplies. LNG imports have increased from a low of 25 bcf in 1995, to 198 bcf in 2000, and to 445 bcf in 2004. Whether imports will continue to increase depends on whether facilities can be built to store, re-gasify, and send it into the interstate gas transmission system.[19]

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[19] The *AEO2006* reference case projection for U.S. imports of liquefied natural gas (LNG) is lower than was projected in the *AEO2005* reference case as more rapid growth in worldwide demand for natural gas reduces the availability of LNG supplies to the United States and raises worldwide natural gas prices,

Imports of LNG in the first half of 2005 totaled 314 bcf, or just 6 bcf more than LNG deliveries during the comparable period last year, according to preliminary data from the Office of Fossil Energy, U.S. Department of Energy. Through the first six months of the year, the Dominion-owned Cove Point LNG terminal, located on the Maryland coast of the Chesapeake Bay, received 119 Bcf, which was the largest volume received at any of the terminals. Tractebel's Everett facility, located near Boston, Massachusetts, received 88.2 bcf, the second largest volume of LNG. El Paso's Southern LNG terminal received 55.4 bcf, while Trunkline LNG received 48.7 bcf. Trinidad and Tobago delivered to the United States the most LNG of any source country, providing 242 bcf from the Point Fortin plant. Algeria was the source of approximately 52 bcf, while Egypt supplied 5.7 Bcf. Nigeria, Malaysia, Oman, and Qatar delivered the remaining 14 bcf. High natural gas prices in other world markets during the first three quarters of 2005 have served to attract available supplies of LNG that might otherwise have been directed to the United States, although fourth quarter imports are estimated to increase in response to high U.S. prices. Currently, total LNG imports for 2005 are expected to be approximately 650 bcf; LNG imports are projected to be just over 1,000 bcf in 2006.

Supplies of natural gas from overseas sources account for most of the projected increase in net imports in all forecasts. In 2001, the industry began the process of reopening mothballed liquefied natural-gas terminals and proposed building dozens of new ones. The Bush administration backed the effort, and the federal government streamlined the regulatory process. Companies campaigned to persuade communities to allow them to build terminals, often in the face of local opposition.

After facing federal reviews, the lengthy process of building new terminals has begun and new LNG terminals are projected to start coming into operation in 2006. In 2005, EIA had projected net LNG imports increase to 6.4 tcf in 2025. The *AEO2006* reference case now projects LNG imports to increase from 0.6 tcf in 2004 to 4.1 trillion cubic feet in 2025 (about two-thirds of the import volumes projected in the *AEO2005* reference case) and to 4.4 tcf in 2030.[20]

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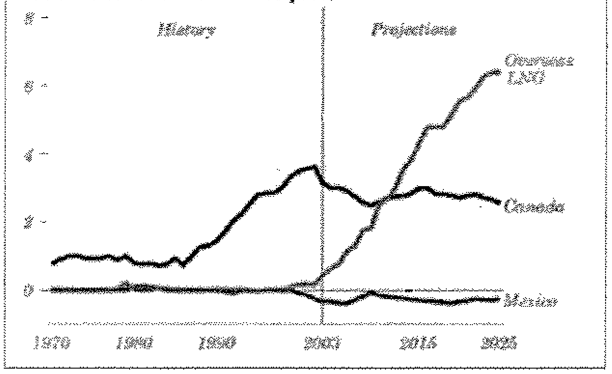
making LNG less economical in U.S. markets. LNG imports are expected to grow from 0.6 tcf in 2004 to 4.1tcf in 2025 as compared with 6.4 tcf in the 2005 report.

[20]T he growth in LNG imports in is moderated by three factors: higher natural gas prices reduce domestic consumption; higher world oil prices increase worldwide demand for natural gas and LNG imports, which raises the price of LNG; and, to a lesser extent, higher world oil prices lead to higher foreign demand for GTL production, which uses more natural gas as a feedstock.

Figure 85. Net U.S. imports of natural gas, 1970-2025 (trillion cubic feet)



Source: EIA Annual Energy Outlook 2005

Notable events in 2005 include the first receipt of LNG deliveries from Egypt, and the opening of a new U.S. import facility. On June 5, 2005 the Gulf Gateway Energy Bridge, the first new LNG port in the United States in over 20 years, began operations and received one cargo carrying 2.6 Bcf from Malaysia in March. Unlike the other four operating terminals, Gulf Gateway is located offshore (in the Gulf of Mexico), where it receives re-gasified natural gas from carriers specially equipped to vaporize LNG onboard. The terminal is little more than a high-tech submersible buoy and miles of connecting pipeline, but the imaginative twists taken by the operator, Houston's Excelerate Energy, are providing another way for the United States to satisfy its growing appetite for the fuel.

Excelerate's design avoids the need for large fixed facilities to turn the super cooled liquid into a gas by putting that equipment aboard the tanker. Excelerate's system, called the Energy Bridge, centers on a specially designed buoy anchored 100 feet below the surface by eight lines when not in use. The liquid natural gas stored on the tanker is returned to its gaseous state aboard the ship and fed through the buoy into a flexible pipe, which connects to a subsea pipeline that brings the gas to shore. The Excelsior, one of three ships Excelerate has planned, has storage capacity for 3 billion cubic feet of LNG. It can regasify and offload up to 500 million cubic feet through the buoy per day. On April 25, the second ship, the Excellence, will be launched. The third ship, the Excelerate, is expected to launch in Oct. 2006.

In late January, Freeport LNG broke ground for the first new onshore terminal in the continental United States in more than 20 years. The terminal, located on Quintana Island, Texas, is expected to be complete in late 2007. Freeport LNG in 2005 also filed with the Federal Energy Regulatory Commission (FERC) to expand the terminal regasification capacity to 4 bcfd, which would make it the largest in the United States. Cheniere Energy started construction of its Sabine Pass terminal in Cameron Parish, Louisiana, in March, after the terminal received final approval from FERC in late 2004. Operations at the Sabine Pass terminal are expected to begin in late 2007 or early 2008. Cameron LNG, which was approved by FERC in December 2003, also began construction in November and expects to begin commercial operations by late 2008. The terminal's owner, Sempra LNG, signed an agreement to provide Tractebel LNG North America up to one-third of the capacity, or about 500 mmcfd for 20 years. Additionally, Italy's ENI signed a preliminary agreement with Sempra to take 600 mmcfd of capacity for 20 years. Federal regulators continued review of numerous LNG terminal applications, approving six terminals in 2005. ExxonMobil received approval from FERC for two terminals: the Golden Pass project near Sabine Pass, Texas, and the Vista del Sol terminal near Corpus Christi, Texas, each with the capacity to deliver up to 1 bcf per day into the pipeline grid. FERC also approved Cheniere Energy's Corpus Christi LNG project in Texas; Hess LNG in Fall River, Massachusetts; and Occidental's Ingleside Energy in Texas. MARAD has approved Shell's Gulf Landing offshore LNG terminal to be located 38 miles off Cameron, Louisiana. The gravity-based structure will have a peak send-out capacity of 1.2 bcf per day.

Deliveries lag in 2005

The tremendous year-over-year growth in LNG deliveries since 2002 did not continue in 2005. The theory was that if the U.S., the world's largest gas consumer, opened for imports, there would be tankers lining up to discharge their cargo. Instead, a pressing global shortage has developed, in part because of overseas competition. As the price of liquefying natural gas fell, a global building boom began. While supply increased and the number of cargoes available for purchase on the spot market grew, so too did the number of new import terminals in other countries. Global production capacity for natural gas, in liquefied form, is about 20 bcfd, but there are now enough terminals around the globe to eat up twice that volume, according to the Federal Energy Regulatory Commission.

Deliveries of LNG to the United States during the last half of 2005 had been expected to pick up with a large expansion of export capacity in Nigeria, Trinidad and Tobago, and Egypt. The four existing onshore terminals are importing only about half the volume they can handle. Although natural gas prices remain elevated in the United States relative to historical standards, global competition for uncommitted cargos and temporary supply constraints in the Atlantic basin has contributed to the slower growth of LNG imports in 2005. A global shortage has developed in recent months, amid supply glitches, cold weather in the United Kingdom and a drought in Spain, which has been turning to liquefied natural gas to make up for a shortfall in hydroelectric power. U.S. buyers are being aggressively outbid by Europeans and Asians for the limited number of cargoes available. Recently, the Spanish have been willing to pay $2 to $3 mmbtu above Gulf Coast spot prices, according to PIRA Energy Group, a New York consultant. South Koreans, meanwhile, are paying a premium of about $2 and the British a premium of $2 to $6. Through November, the last month for which official data is available, LNG imports totaled 580 bcf, or an average of 53 bcf per month. If this pace continued in December, total receipts for the year would be less than 3 percent below the 652 bcf received in 2004. The four active onshore terminals operated at an estimated 60% of capacity during the year.

Spot liquefied natural gas prices have surged to record highs near $10 per MMbtu. Hurricane Katrina has reduced U.S. natural gas output while LNG projects in Nigeria, Australia and Egypt have lost nearly 1.6 million metric tons of output due to production problems in August and early September. The LNG plant problems mean between 22 and 24 cargos have been lost this summer, putting upward pressure on spot prices.

Geography also puts the U.S. at a disadvantage. Most supplies of liquefied natural gas for Europe and the U.S. come from West Africa, the Mediterranean and the Middle East. Europe is closer, which makes delivery less expensive. The only supplier close to the U.S. is in Trinidad. Ironically, last year, a tanker from Trinidad arrived in the U.K. according to Waterbourne LNG, a weekly publication of Houston energy consulting firm Commercial Services Co. The voyage marked one of the first times liquefied natural gas from the Caribbean had crossed the Atlantic in pursuit of higher prices.

Safety and siting are huge concerns for local communities

The proposals for new receiving terminals have unleashed emotional debates in the communities where they are to be built. Officials in some states where energy companies plan to build terminals that would receive the gas tankers - including Alabama, California, Maine, Massachusetts, New Jersey, New York and Rhode Island - say they could fall victim to a catastrophic explosion, either accidental or set by terrorists. To counter local delays, a provision was slipped into a $388 billion USG spending bill just before Congress adjourned in November 2004. The provision reasserts that the FERC has "exclusive jurisdiction" over LNG permits and that the 1938 law regulating natural gas transportation "pre-empts" states on approving natural gas infrastructure "associated with interstate and foreign commerce." The Energy Policy Act of 2005 signed by President Bush affirmed the FERC's exclusive authority under the Natural Gas Act to oversee the siting, construction, expansion and operation of new LNG import and export plants. It does not provide FERC with eminent domain authority over siting LNG facilities and states still have the ability to effectively veto an LNG plant by denying permits associated with the Clean Water Act, the Coastal Zone Management Act, and the Clean Air Act.

The commission had already asserted formally that it has final permitting authority over LNG terminals but in a California case it is being challenged. The California Public Utility Commission (CPUC) has argued that state officials should be involved in approval of a site being proposed for Long Beach, California to ensure it addresses state environmental and safety concerns. For two years, Long Beach has debated a proposed $450 million energy terminal, weighing environmental and safety concerns against the demand for new jobs and much-needed natural gas.

State energy regulators are suing the federal government over the right to decide where some of the terminals are built, if they're built at all. The energy bill language appears designed to bolster FERC's side of the lawsuit, and could profoundly affect California's case, said Harvey Y. Morris, principal counsel for the Public Utilities Commission. The dispute is now before the 9th U.S. Circuit Court of Appeals.

On the safety side, in December 2003, the FERC commissioned ABSG Consulting Inc. to identify appropriate consequence analysis methods for estimating flammable vapor and thermal radiation hazard distances for potential releases from LNG vessels. At the same time the DOE commissioned the Sandia National Laboratories to conduct a study of the potential for breaching an LNG tanker either accidentally or intentionally. The reports were released in May and December 2004 respectively. The Sandia report said that although the risks from a terrorist attack could be severe, techniques exist to reduce the potential impact. [21]

Adequate sites will be approved

Would-be developers have identified some 50 North American sites, onshore and offshore, as potential spots for new LNG terminals in the U.S and Mexico. Planned expansions at the four existing terminals are underway and new LNG terminals are projected to start coming into operation in 2008, while a considerable number are awaiting approval. Siting and permitting and other regulatory issues are most frequently named as the most significant challenge in expanding LNG imports.

The number of terminals FERC has approved so far would have been a surprise a couple of years ago. The seven terminals that have been approved for the onshore Gulf Coast essentially satisfy US requirements for additional LNG import capacity. Once a few start to get built and it becomes clear that the market can't sustain many more, other LNG terminal proponents likely will be forced to drop out. Two LNG import terminals in Atlantic Canada-Anadarko's Bear Head facility in Nova Scotia and Irving Oil's Canaport facility in New Brunswick-appear well on their way to fruition, which could scuttle plans for siting new terminals anywhere in New England, and particularly in LNG-resistant Maine.

An end to open access terminals

Consumer advocates and environmentalists filed a motion with the Federal Energy Regulatory Commission in May 2005 to oppose a proposal by the Dominion Cove Point facility in Calvert County to become the first operational liquefied natural gas terminal in the country to gain exemption from competitive bidding and public disclosure requirements. Under the original regulatory system, plants were required to allow all gas importers access to their facilities on a non-discriminatory basis. The terminals could charge only the cost of providing service with a specific profit margin added on. The entire bidding process and cost-based rates were tightly regulated. Federal energy regulators agreed. In the Hackberry decision, the commission said a proposed plant in Louisiana could contract directly with energy companies without a public bidding process. It also said the rates do not need to be based on the cost of providing service. Cove Point has asked the commission to apply the Hackberry rule to two new storage tanks it plans to build to boost the plant's overall storage from 7.8 bcf to 14.6 bcf.

[21] ABSG Consulting Inc., "Consequences Assessment Methods for Incidents Involving Releases from Liquefied Natural Gas Carriers," (2004); Sandia National Laboratories, "guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water," Rep. No. SAND2004-6258, Dec. 21. 2004.

The issue won't be lack of terminals but lack of supplies

CERA has done considerable analysis of the emerging LNG markets and makes the observation that developing the full potential of LNG could cost upward of $200 billion worldwide, and energy companies will have to choose between investments in LNG and other investments. The greatest bottleneck to growing the (US) LNG market may be in new liquefaction facilities, apart from potential siting issues around new receiving terminals. In fact, accessing foreign LNG to import has become more of an intractable problem than getting terminals permitted. For most LNG project sponsors the major issue is supply at this point. The U.S. was a very attractive market for LNG suppliers a few years ago due to high gas prices relative to the rest of the world. But the recent run-up in global oil prices has had a corresponding impact on LNG pricing so that the United States now presents not much of a difference in terms of price.

The pace of constructing new supply facilities is critical to LNG availability for a long-term increase in imports. As described by one analyst, terminals are a comparatively small part of the total LNG chain. They are the "tail" wagging the "Dog", the "Dog" being the liquefaction facilities. Less than 13% of the CAPEX is located in the receiving country while at least 50% is located in the production facilities.

Forecasts of new liquefaction capacity in the medium term vary greatly and the more conservative forecasts site the lack of proven LNG contractors, funding, and technical supply restraints, and the rising cost and availability of critical materials as reasons for the lower estimates. [22]

Potens & Partners, Inc- a shipping consultant, estimated in 2005 engineering and construction contracts were up from $200/ton of capacity to $350. High steel and nickel prices (important for cryogenic and stainless grades of steel) and shortage of knowledgeable EPC contractors may be inflating costs 7.5 to 10% a year. Until 2003, two LNG trains a year were being constructed. Now we are looking at as many as 10.

While LNG development may be lagging in the United States, it is proceeding apace elsewhere. Already, Japan, South Korea, and Taiwan account for 68% of global LNG imports. Europe accounts for another 28% of LNG imports, with the United States importing 4%. LNG facilities are being expanded in these countries, and introduced in several others, including China, India, Indonesia, the Philippines, New Zealand, Mexico, Portugal, the Netherlands, and the United Kingdom. Having adequate receipt capacity only gives the U.S. a seat at the table enabling it to compete with Europe and Asia for LNG Supplies.

At present, the Atlantic Basin regasification capacity represents only 25% of total world capacity. But based on projects currently in the planning or construction stage, 74% of

[22] At the 8th Annual Rice Global Engineering & Construction Forum at Rice University in Houston, Texas, the President of Transmar Consult, Inc., J.P. Chevriere, reviewed the results of a multi-client study of available technical resources and concluded that the more optimistic forecasts for LNG development weren't feasible.

total world regasification capacity growth over the next five years will occur in the Atlantic Basin. This will make the Atlantic and Pacific Basins roughly equal in terms of regasification capacity (O&GJ).

Already rising fuel demand in Asia, Europe and the U.S. are pushing liquefied natural gas prices to record highs. The November 2005 U.K. price may have been a record for spot LNG anywhere in the world.

Additional pressure on US supplies may occur as European countries look for ways to decrease dependence on Russian supplies. EU energy ministers met on Jan. 4 to discuss energy supply security given that Russia is the largest gas producer in the world and has large reserves, it has generally been assumed that much of the EU's additional needs for gas would be met from that supplier. While that is likely to remain the case, the Russian Ukraine gas price conflict may mean that more attention will be given to other options some of which will increase competition for LNG otherwise destined for the U.S.:

- The Middle East and North Africa.
- The Caspian region.
- Nigeria, Angola and Mauritania.

The interchangeability and quality of LNG supplies is a manageable issue.

The composition of regasified LNG is of heightened interest as concerns focus on Btu content and dewpoint levels. LNG produced worldwide has a considerable range of heating values and the ability to receive the full range of Btu levels would give the US more supply options. For domestic supplies this has not been an issue. The petrochemical industry extracts ethane and propane from the natural gas stream and sells it separately producing a leaner domestic gas. Many US pipelines now set maximum limits on the btu value or the hydro carbon dewpoint in their transportation tariffs.

In 2004, the FERC instituted proceedings to address gas quality issues and interchangeability. Working with the Natural Gas Council, two reports were produced on February 28, 2005[23] dealing with the technical issues surrounding interchangeability including control parameters, safety and reliability. FERC is now in the process of establishing gas quality and interchangeability standards. LNG developers will have to consider management systems to deal with these issues.

The issue of gas interchangeability for domestic LNG facilities hasn't been resolved although it should prove less of a problem for Gulf-area facilities that have access to a huge pool of gas for mixing with imports, thereby equalizing the heat content. Outside the Gulf, LNG terminal developers will have to look at expensive technologies to bring down the heat content.

[23] "White Paper on Liquid Hydrocarbon Drop Out in Natural Gas Infrastructure" and "White Paper on Natural Gas Interchangeability and Non-Combustion End Use."

Will LNG be controlled by a cartel?

U.S. policy makers also express concern about increasing the US dependence on foreign imports. Increasing the United States' reliance on non-North-American natural gas raises a host of geopolitical questions. With the country already dependent on overseas oil, is it wise to head the same route with gas? The concept of a natural gas OPEC is becoming less far-fetched. On April 25-27, 2005, a little-known, four-year-old organization called the Gas Exporting Countries Forum met in Port of Spain, Trinidad and Tobago. The Trinidadian hosts listed the countries invited as forum members as Algeria, Bolivia, Brunei, Egypt, Indonesia, Iran, Libya, Malaysia, Nigeria, Oman, Qatar, Russia, Trinidad, United Arab Emirates, and Venezuela. Many are OPEC members. Norway, Argentina, and Equatorial Guinea were invited to observe.

Recent events between Russia and the Ukraine have also served to illustrate the risk other markets, particularly those in Europe, can face in terms of security of gas supply. A major disruption to European supplies can and will have spill-over effects that will be felt not only on that continent but in the U.S. While this episode is behind us, worldwide gas supplies are increasingly being sourced from what most consider to be less stable, or perhaps more politically activist, regions.

Gas is arguably more vulnerable to unforeseen interruptions of supply. Oil is reasonably easy to trade, but in most gas markets the pipeline between the gas field and the gas burner locks producers and consumers in an exclusive embrace. But a market in tradable LNG is rapidly emerging. Billions of dollars will be invested in LNG over the next decade and there might even be routine price arbitrage between markets.

Turning to Mexico for new sites

The Long Beach project is the lone remaining onshore gas terminal in California being considered after public opposition killed other projects. Three offshore projects — one off Camp Pendleton and in Ventura County — are still alive. With controversy raging in California over the proposed sites, developers have turned to Mexico.

In Mexico, the Repsol YPF plant would be built in the Pacific port city of Lazaro Cardenas in the state of Michoacan and would supply gas via pipeline to Mexico City, the energy-hungry capital almost 200 miles away. Other re-gasification terminals are under construction just north of Ensenada in Baja California — the first ever on North America's Pacific Coast — and in Altamira in Tamaulipas state on the Gulf of Mexico.

Three additional proposed terminals, including a second plant at Ensenada and others at Pacific ports Manzanillo and Rosarito, are in various stages of the approval process.

The first Ensenada plant is being developed by Sempra Energy of San Diego, parent of Southern California Gas Co. and San Diego Gas & Electric Co. The company plans to sell more than half the gas in the United States. Construction on the Ensenada plant began this year; the plant is scheduled to begin re-gasifying fuel shipped from Indonesia in late 2007.

Other re-gasification terminals are under construction just north of Ensenada in Baja California — the first ever on North America's Pacific Coast — and in Altamira in Tamaulipas state on the Gulf of Mexico.

Three additional proposed terminals, including a second plant at Ensenada and others at Pacific ports Manzanillo and Rosarito, are in various stages of the approval process.

The US needs billions in new gas infrastructure to integrate these supplies into the pipeline system

An INGAA Foundation study concluded that $61 billion of new investment would be needed to build the approximately 45,000 miles of pipelines and 7.8 million horsepower of compression to meet growing gas demand. Future pipeline projects will be focused on bringing additional supplies from the Rockies and integrating the imported LNG into the interstate system.

An EIA report reviews the level of growth that occurred within the U.S. natural gas transportation network during 2004.[24] Although capacity additions in 2004 were almost 27 percent less than in 2003 (7.7 vs. 10.4 bcfd), there were several significant developments in 2004. Six new pipeline systems with a total of 1.8 bcfd of additional capacity in the deepwater Gulf of Mexico were built and the extension of the Cheyenne Plains Pipeline, a 560 mmcfd system became operational in December 2004. Additionally, El Paso Natural Gas's southern leg expansion of 320 mmcfd was completed in May 2004 and several new non-interstate pipelines were installed in Texas in 2004 to increase transportation services between East Texas production fields and interstate and non-interstate pipeline interconnections within the State.

El Paso Corp. is also planning a new 1,000 mile pipeline project to move up to 2 bcfd of natural gas production from the Rocky Mountains to the Midwest and East Coast. Unlike natural gas produced in the Gulf Coast region, which reaches many parts of the country via a well-established pipeline network, Rocky Mountain natural gas has access to fewer markets. This has kept prices for gas there lower than in other regions. For example, in October wholesale natural gas in Opal, Wyoming, sold for $11.47 mmbtu, a 24% discount to Tuesday's New York Mercantile Exchange price, which closed up 20 cents to $14.22.

El Paso's project is at least the third major pipeline project announced this year to link the Rockies, where natural gas output is growing rapidly, with other markets. In March, Williams Cos. proposed an expansion of its system to link Wyoming, Colorado and Utah fields with the Northwest. And in August, Houston-based Kinder Morgan Energy Partners proposed a $3 billion, 1,500 mile pipeline project with San Diego-based Sempra Energy to connect the Rockies with eastern markets by way of Ohio.

[24] "Changes in U.S. Natural Gas Transportation Infrastructure in 2004." June 21, 2005,

Currently there is a "race to the east" as producers in Texas build interconnects to the interstate lines east of Texas deliver to the northeast. Already blocked from markets north and west by Canadian and Rocky Mountain gas, they fear the new LNG terminals will capture the northeastern markets at their expense. While the amount of capacity added in 2004 was the least since 2000, proposed projects for 2005-2007 total 44.4 bbcfd.

COAL, NUCLEAR AND RENEWABLE TECHNOLOGIES

It's back to the future for coal

In *AEO2006*, coal remains the primary fuel for electricity generation through 2030, with the coal share of total generation increasing from 50% in 2004 to 57% in 2030. Over this period, utilization at existing plants increases and large amounts of new coal-fired capacity is added, mainly after 2020. The natural gas share of total electricity generation is projected to increase from 18 percent in 2004 to 22% around 2020 before falling to 17% in 2030. A total of 174 gigawatts of new coal-fired generating capacity, including 19 gigawatts at coal-to-liquids plants, and 140 gigawatts of new natural gas capacity are projected to be constructed between 2004 and 2030.

There have been 118 recent announcements to build new coal-fired plants in the US. These proposals represents the largest increase in such projects since the 1970's and would involve $100 billion in capital expenditures if all the plants were built. Coal is being promoted as a secure domestic alternative to natural gas and there are dozens of different coal and natural gas complexes currently competing for financing. But experts caution that perhaps no more than half of all proposed plants will ever be built. It can take seven to 10 years for a coal power plant to go from planning to construction — and legal action and public protests often halt them. The burning of coal already produces more airborne mercury and greenhouse gases than any other single source.

The reason for coal's resurgence is an intensifying fear in the United States that natural gas supplies will become scarce and more expensive. Coal has remained relatively cheap and the United States has the world's largest coal reserves. While it costs more to build a coal-fired plant than it does to build one to using natural gas, the running cost of a gas plant has soared in comparison with coal. A typical coal-fired power plant spends 2 cents per kilowatt-hour to fuel its operations, compared with 5 cents per kilowatt-hour for a plant fueled by natural gas at today's prices.

As natural gas prices rise later in the forecasts, new coal-fired capacity is projected to become increasingly competitive, accounting for nearly one-third of all the capacity expansion expected over the forecast. Two new coal-fired plants (just over 1 gigawatt of capacity) are already under construction, scheduled for operation by 2006. From 2011 to 2025, 105 gigawatts of new coal-fired capacity is expected to be brought on line- more than one-half of it after 2020. From 2011 on, coal-fired capacity is expected to account for 40% of all capacity additions.

According to some electric utilities interested in both coal and gas-fired generation, despite rising coal prices, gas prices would need to fall to less than $4 mmbtu while average contracted coal prices would need to reach $2 mmbtu delivered for gas to gain a real cost advantage over coal. Unlike natural gas, coal prices are likely to remain stable, and give up little or none of the comparative price advantages gained in recent years. The U.S. has a quarter of the world's coal reserves- enough to last centuries at even expanded levels of use as well as an extensive coal production and delivery network that makes almost all its reserves readily accessible. Thus, while spot prices may occasionally surge, long- term prices should remain stable as production is increased to meet the higher demand.

Coal production maxed out for now

Forecasts show coal-fired capacity increasing 1% a year but will declining in its share of the market (47% in 2002 to 43% in 2030). Coal demand will grow the most among all energy sources. *Oil and Gas Journal* forecasts that the use of coal will total 22.9 quads this year, climbing 2.3%, spurred by increased economic activity and high oil and gas prices. EIA in their December 2006 estimate said that U.S. coal production will grow by 0.8% in 2005 and by an additional 3.9% in 2006. Coal prices to the electric power sector increased significantly in the first half of this year, growing by 15.3% compared with the first half of 2004. Coal prices are projected to increase by an average 13.2% in 2005 and by an additional 5.0% in 2006, rising from $1.35 mmbtu in 2004 to $1.61 mmbtu in 2006.

Wyoming coal prices are at an all-time high amid a series of train derailments out of the Powder River Basin and unrelenting demand among electric utilities as they try to avoid even steeper natural gas prices. Powder River Basin coal producer contracts being struck for 2006 delivery are $15.45 per ton -- up from around $10 per ton in July and $7 per ton October a year ago. This past summer's railroad woes limited efforts to boost production beyond the basin's record 381.7 million tons set last year. The price of a futures contract for a ton of coal in the Western United States rose from about $9 in June to $19.50 in October. According to EIA, coal remains economical. In July 2005, it cost about $17 to generate a megawatt of electricity for an hour using coal. It cost $59 to generate the same energy with natural gas and $64 with liquid fuels, such as kerosene, he said. Coal is expected to hold tight to its 52% of the electrical generation market.

A new generation of coal plants?

Building gasification plants like IGCC is still more expensive than building conventional coal-fired power plants because the technology is new and construction and operating uncertainties raise financing costs. But loan guarantees that cover 80% of the construction costs of these plants would substantially lower the cost of power. Such finance plan could make clean-coal gasification technology more affordable for companies and utilities willing to invest and produce affordable synthetic gas at $4 in a $7 mmbtu natural gas market. Tax credits in the recent energy bill are important because they offer more incentive to invest in new technologies. The energy bill contains 15%

and 20% investment tax credits for clean-coal facilities producing electricity; and a 20% credit for industrial gasification projects.

The Bush administration pushes coal

Joining the rush to coal, the Bush administration has significantly shifted policy away from three decades of federal efforts to reduce the nation's dependence on coal, which is significantly cleaner than it once was, but still dirtier than natural gas. It is supporting the push for a new wave of coal-fueled energy and the Energy Department is investing $2 billion in ventures intended to make coal less polluting. DOE's increased focus on coal has prompted an array of new ideas. Waste Management and Processors Inc. of Gilberton, Pa. is building a power plant to produce industrial heat and electricity from raw anthracite waste. The $612 million project uses a coal gasification process. The Energy Department will pay $100 million for the plant that turns wastes into syngas.

The FutureGen project was first proposed in 2003. Recently the Bush Administration brought aboard partners from the energy sector, including American Electric Power, Southern Company, and Foundation Coal who will collectively contribute $250 million to the project. The bulk of the $620 million that the DOE plans to provide on its own was allotted in the energy bill that passed this past August. The government hopes to receive the rest of the needed money from other energy R&D funds and an unnamed group of "international partners."

FutureGen aims to build a demonstration facility that would generate virtually zero-emission electricity from coal -- billed by industry as "clean coal" -- within the next decade. It would use "integrated gasification combined-cycle" (IGCC) power-plant technology that first pressurizes coal to produce a vapor, then filters carbon dioxide and smog-causing pollutants from the gas before burning it. The captured greenhouse gases would then be stored underground where they couldn't contribute to atmospheric warming -- a technique known as "sequestration."

FutureGen would be the first demonstration plant in the world to combine the coal gasification process with carbon capture and sequestration according to DOE. Although a growing number of green groups like NRDC, the World Resources Institute, and the Sierra Club are opening up to the idea of advanced coal and carbon sequestration, they haven't endorsed the FutureGen plan. Many U.S. activists see it as a costly and slow-moving PR gambit rather than a straightforward bid to advance cleaner energy production.

The Erora Group, a Louisville development and consulting company, hopes to break ground by spring 2007 on a $1 billion coal-gasification plant at a former coal mine in Henderson County's Cash Creek community, and it has plans for a similar plant in the central Illinois town of Taylorville.

Cinergy/PSI is considering a coal-gas plant in Edwardsport, Ind., 110 miles northwest of Louisville. And American Electric Power, owner of Kentucky Power, plans to build a gasification plant in Ohio and is considering Kentucky for a second project.

A U.S. Department of Energy-subsidized plant in Florida, Tampa Electric's Polk Power Station, has been generating electricity with coal gas since 1996. The Wabash River Coal Gasification Repowering Project outside West Terre Haute, Ind., another Energy Department-funded pilot program, began operations in 1995.

EPA rewrites the new source review regulations and existing coal plants profit

One of the greatest obstacles to expanding the use of existing coal plants was EPA's new source review regulations. Most old coal plants were exempted from the Clean Air Act requirements the reasoning being that they would soon be retired. Instead, many of the plants have expanded their capacity which should have brought them under the more stringent regulations required for a new plant or new source. Former President Clinton used the regulations to bring suits against 51 aging, coal-burning power plants, primarily in the Ohio Valley and the South. Those new regulations had been placed on hold while federal courts review challenges to them by state officials and environmental and health groups.

The Bush administration in 2002 and 2003 rewrote the EPA's new source review regulations. Bush administration and industry officials argue that the federal government should not press for expensive new pollution controls because it would cost jobs and raise electricity prices, but environmentalists say this policy puts public health at risk.

On August 27, 2003, the EPA issued a final rule defining certain power plant and industrial facility activities as "routine maintenance, repair and replacement," which are not subject to new source review (NSR). These revisions should enable coal plant operators to continue maintaining their plants and increase their use with less worry about triggering NSR.

The courts agree

A federal appeals court affirmed the administration's approach to calculating polluting emissions from aging power plants, rejecting 13 states' contention that it violates the Clean Air Act. Although the U.S. Court of Appeals for the District of Columbia Circuit's three-judge panel questioned the Environmental Protection Agency's plan to loosen pollution record-keeping requirements, it held that in determining whether a power plant is complying with the law, utilities can compare the pollution they emit after an upgrade with their highest levels over the previous 10 years. These developments should have a dramatic impact on ongoing litigation, out-of-court settlements, and new enforcement actions against coal-fired electric plants.

Under the new standard, a modernized plant's total emissions could rise if the upgrade allowed it to operate longer hours. In court filings, the EPA estimated in 2002 that an hourly standard would allow eight plants in five states -- including Maryland, Virginia and West Virginia -- to generate legally as much as 100,000 tons a year of pollutants that would be illegal under the existing New Source Review rule. That equals about a third of their total emissions.

Even so, Justice Department officials have continued during the Bush presidency to negotiate settlements in which many of the sued utilities agreed to pay stiff fines and install new pollution controls costing in the tens of millions of dollars. They have also filed six lawsuits against other coal-burning power plants since Bush took office.

But mercury pollution controls remain a big issue

On the negative side for coal, the EPA is also currently developing regulations to reduce emissions of fine particulates and mercury from electric power plants. Efforts to reduce emissions of particulate matter less than 2.5 microns in diameter (PM2.5) began with the issuance of National Ambient Air Quality Standards (NAAQS) on July 16, 1997. EPA has proposed regulating mercury emissions US electric plants. EPA believes that mercury level is found in fish consumed by Americans is unhealthy and that limiting mercury emissions from power plants the amount of mercury. (EPA 1997 Mercury Study to the U.S. Congress).
The health impact of mercury emissions has been estimated by the Harvard Center for Risk Analysis and the Mt. Sinai School of Medicine's Center for Children's Health and Environment I the range of several billions dollars a year in health costs. March 15 EPA rules have been criticized for allowing existing mercury reductions in the western United States to continue until 2018. The problem has been exacerbated in the west by the increased utilization of existing plants. 8-10,000 MW of new capacity is considered viable. Environmental groups argue that the technology exists to cost-effectively solve this problem by utilizing existing technologies such as sorbent injection, electro-catalytic oxidization (ECO) and EPA estimates that plants can reduce 90% of the mercury emissions at a cost of .003 to 2.0 mills/Kwh, including operation and maintenance. Xcel Energy recently settled with the EDF, Western Resource Advocates and agreed to use modern mercury specific technology on their proposed 750MW sub bituminous coal plant in Pueblo Colorado.

On March 15, 2005, EPA issued the Clean Air Mercury Rule to permanently cap and reduce mercury emissions from coal-fired power plants for the first time ever. This rule, combined with EPA's Clean Air Interstate Rule (CAIR), will significantly reduce emissions from the nation's largest remaining source of human-caused mercury emissions. Environmentalists and health officials view the new rule, which includes a pollution trading scheme, as unlikely to make much difference in mercury pollution for more than a decade.

On September 13, 2005, with a 51-47 vote, the Senate defeated a resolution to void the Environmental Protection Agency rules finalized last March. The Democrats and nine Republicans who supported the repeal contended the EPA approach was too slow and too weak in dealing with a pollutant that can cause serious neurological damage to newborn and young children.

The states lead the way on Kyoto

President Bush pulled the United States out of the Kyoto treaty and remains opposed to mandatory curbs on greenhouse gases, saying they are too expensive for the U.S. economy. But more than two dozen states have moved to fill in the void, adopting regulations and policies designed to discourage emissions or encourage the use of renewable energy. Officials in New York and eight other Northeastern states have come to a preliminary agreement to freeze power plant emissions at their current levels and then reduce them by 10% by 2020, according to a confidential draft proposal. Once a final agreement is reached, the legislatures of the nine states will have to enact it, which is considered likely.

The regional initiative would set up a market-driven system to control emissions of carbon dioxide, the main greenhouse gas, from more than 600 electric generators in the nine states. Environmentalists who support a federal law to control greenhouse gases believe that the model established by the Northeastern states will be followed by other states, resulting in pressure that could eventually lead to the enactment of a national law.

Emissions would be capped at 150 million tons of carbon dioxide a year, a figure that is about equal to the average emissions in the highest three years between 2000 and 2004. Each of the nine states would have its own cap. New York's, at 65.6 million tons, would be the largest. Vermont's would be the smallest, with 1.35 million tons.

The caps would be enforced starting in 2009. By that time, restricting emissions to levels prevailing now would, in effect, require a reduction of emissions relative to power output, because electric generation is expected to increase between now and then. The 150 million-ton cap would be sustained through 2015, when reductions would be required, reaching 10% in 2020. The Kyoto protocol freezes emissions at the 1990 level and imposes a 7% reduction in 2012. One part of the proposal that is not yet final deals with the sale of emission allowances under a cap-and-trade system

Earlier in 2005, for example, the mayors of more than 130 cities, including New York and Los Angeles, joined in a bipartisan coalition to fight global warming on a local level by agreeing to meet the emissions reductions contained in the international pact. California, Washington and Oregon are in the early stages of exploring a regional agreement similar to the Northeastern plan.

Some companies feel that if we don't act soon in the United States, we may be missing out on opportunities to innovate and to develop the technologies that will address these problems in the future. Some of America's top corporate leaders are starting to talk about tax increases and caps on emissions, a sharp contrast to the stance of U.S. business and industry just a few years ago, when the emphasis was on delaying mandatory restrictions as long as possible. In April 2005, the Chairman and CEO of Duke Energy called for a national carbon tax to provide incentives for lower carbon emissions and new technologies Anderson complained that concern about climate change has led to a costly "patchwork" of local, state and regional policies

<u>The outlook for nuclear is the most optimistic in decades</u>

Currently there are nearly 98,000 megawatts of nuclear generating capacity operating in the United States. Not one new nuclear plant has been ordered in America in over two decades. The last reactor to come on line in the United States was the Tennessee Valley Authority's Watts Bar reactor in May 1996--after 24 years of construction during which the Three Mile Island accident, increasing government regulation, cost overruns, environmental protests, and the Chernobyl disaster helped put the industry into suspended animation. Nonetheless, the outlook for nuclear power is upbeat

At the center of the waste dispute is the federal government's controversial plan to transport spent nuclear fuel and high-level radioactive waste across the country and permanently store it at its repository in Yucca Mountain, Nev.

The nuclear industry is gaining regulatory approval for extending the operating licenses of existing reactors. Originally these reactors were licensed to operate for 40 years, but after extensive safety analysis, testing, and structural analysis, the Nuclear Regulatory Commission (NRC) is, on a case-by-case basis, allowing the plants to operate for another 20 years. To date, 10 reactors have received 20-year operating license extensions. Also, 20 reactors have filed for the same operating license extensions, and another 20 reactors are expected to file for operating license extensions during the next six years. A growing consensus is that the entire fleet of existing reactors will be relicensed.

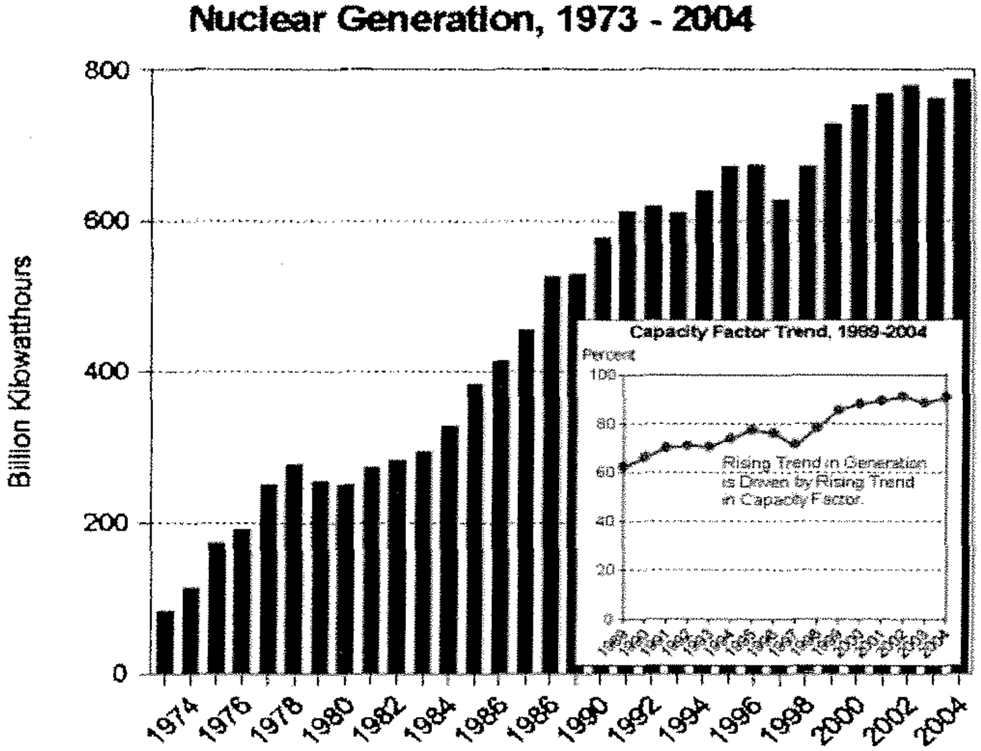
Not only are nuclear plants operating lives being extended, their capacity ratings are being increased. Sophisticated analyses by plant owners and the NRC have demonstrated that large safety margins were incorporated into the original plant designs. Combined with improved instrumentation, new fuel designs, and other plant improvements, the NRC is allowing some nuclear plants to operate at higher power levels than those at which they were originally licensed. The Energy Information Administration (EIA) reports that the U.S. nuclear industry generated 788,556 million kilowatt-hours of electricity in 2004, a new U.S. (and international record). Although no new U.S. nuclear power plants have come on line since 1996, this is the industry's fifth annual record since 1998.

Former NRC Chairman Richard A. Meserve, in recent remarks to the American Nuclear Society, said that during the last 30 years the NRC has approved 80 up-rates that added nearly 4,000 megawatts of generating capacity. Prospective power up-rates, when combined, may result in the effective addition of seven new nuclear power plants, amounting to nearly 7,000 megawatts. A recently completed analysis done for the Energy Information Administration (EIA) documented 1,060 megawatts of power up-rate applications before the NRC and 5,730 megawatts of additional up-rates likely to be submitted within the next seven years. The National Energy Policy prepared under the direction of Vice President Dick Cheney estimates the nuclear up-rate potential at 12,000 megawatts.

Streamlining the permitting process

The NRC has certified several new nuclear reactor designs, obviating the need for review of any technical issues about those designs that were resolved during the certification process. The NRC has certified three designs: General Electric's Advanced Boiling Water Reactor, Combustion Engineering's System 80+, and the Westinghouse AP600. A fourth design, Westinghouse's AP100, is currently being reviewed, and the NRC is engaged in pre-certification discussions with vendors representing five other designs, including gas reactor designs.

The NRC also is proceeding with early site permitting, or advanced approval of a potential site for a nuclear power plant, which may then be banked for future use. Issues resolved in the early site permit review are not reviewed again in the combined license process. The combined license process folds into one proceeding two separate reviews—construction permit and operating license—required of currently operating plants. Once the license is issued the plant may be constructed and proceed to operation after the NRC determines the as-built plant conforms to the approved license. These changes have reduced uncertainty and will result in regulatory decisions as early in the process as practical. Nonetheless, it is unlikely the first kilowatt of new nuclear energy won't be generated before 2015.



The new energy legislation is strong on nuclear

The Energy Policy Act of 2005 includes several incentives to encourage construction of new nuclear plants, including production tax credits, loan guarantees and risk protection for companies pursuing the first new reactors.[25]

- The bill includes an extension of the Price-Anderson Act, an insurance framework for protecting the public in the case of a nuclear incident. The bill extends the Price-Anderson Act for 20 years. The act provides the framework for immediate, no-fault insurance coverage for the public in the event of a nuclear reactor accident.

[25] *AEO2006* includes consideration of the impacts of the Energy Policy Act of 2005 and forecasts that a total of 6 GW of newly constructed nuclear capacity is projected to be added by 2030 due to the incentives in the legislation.

- The legislation authorizes funding for nuclear energy research and development, as well as funding to build an advanced hydrogen cogeneration reactor in Idaho.

- The bill also creates an assistant secretary for nuclear issues at the Department of Energy and authorizes the energy secretary to provide loan guarantees to support the development of innovative energy technologies "that avoid, reduce or sequester air pollutants or anthropogenic emissions of greenhouse gases." These technologies include nuclear energy facilities, renewable energy, coal gasification and hydrogen fuel-cell technology. The loan guarantee can be up to 80% of the project cost.

- The legislation provides a production tax credit of 1.8 cents per kilowatt-hour for 6,000 megawatts of capacity from new nuclear power plants for the first eight years of operation.

- The bill offers new plant investment protection in the form of "standby support" to offset the financial impact of delays beyond industry's control that may occur during construction and during the initial phases of plant startup for the first six new reactors. The bill provides for 100 percent coverage of the cost of delays for the first two new plants, up to $500 million each, and 50 percent of the cost of delays, up to $250 million each, for plants three through six. The standby support covers delays caused by the Nuclear Regulatory Commission's failure to comply with schedules for "inspections, tests, analyses and acceptance criteria," as well as delays caused by litigation.

- The bill authorizes $2.7 billion for nuclear research and development

First steps to a new nuclear plant

Despite strong backing for the industry from the Bush administration, most forecasts predict that no new nuclear units will become operable between 2002 and 2030 because of the inability of a new nuclear plant to compete economically with natural gas and coal-fired units. The EIA report reference case, nuclear capacity grows slightly due to assumed increases at existing units. Nonetheless the US DOE has put into place a program to identify sites for new nuclear plants, to develop new nuclear technologies, and to streamline new regulatory and safety processes resulting in billions of dollars in subsidies to the industry. Nuclear Regulatory Commission Chairman Nils J. Diaz said he expects five or six applications by 2008 and has asked Congress for money to add staff members to handle the applications.

Companies with the strongest capabilities are waiting for someone else to go first. The formation of three consortia to get a plant design licensed for construction is a tentative step toward making a commitment to a new nuclear build. Two of the consortia are asking the Department of Energy for hundreds of millions of dollars to fund their efforts, and the consortia themselves admit that even after successfully completing the NRC licensing process there is no commitment to proceed with construction. Eight power companies, including Exelon and Entergy, are trying to prepare the way for the eventual licensing of a new nuclear plant. Their coalition, called NuStart Energy Development, aims to test a streamlined federal licensing process and to develop a design for a new reactor. In September 2005, NuStart announced which locations it had chosen as part of the group's applications to the Nuclear Regulatory Commission for the construction of and operating licenses for a new commercial reactor.

Investors bullish on nuclear

In the last six years nearly $10 billion in new capital has been invested in the nuclear business, including the acquisition of 38 nuclear generating plants in North America. And as natural gas prices have increased, and the perceived operating and regulatory risks of owning nuclear plants has declined, the prices paid for nuclear plants have increased sharply. Early nuclear power plant sales went for near fire-sale prices-as low as $21 per kilowatt. But more recent acquisitions reflect the intrinsic value of nuclear facilities, or fuel-efficient coal units. For example, the Seabrook plant in New Hampshire was acquired for an estimated $792 per kilowatt, while Millstone 2 and 3 in Connecticut were bought for nearly $700 per kilowatt. Constellation Energy bought the Ginna plant, the most recent nuclear unit to change ownership, for about $862 per kilowatt.

The Greens revisit nuclear

There are growing cracks in what had been a virtually solid wall of opposition to nuclear power among most mainstream environmental groups. In the past few months, articles in publications like Technology Review, published by the Massachusetts Institute of Technology and *Wired* magazine have openly espoused nuclear power, angering other environmental advocates. In recent statements, three top environmental experts - Fred Krupp, the executive director of Environmental Defense, Jonathan Lash, the president of the World Resources Institute and James Gustave Speth, the Dean of Yale's School of Forestry and Environmental Studies - have stopped well short of embracing nuclear power, but they have emphasized that it is worth trying to find solutions to the economic, safety and security, waste storage and proliferation issues rather than rejecting the whole technology. The release of radioactivity at Three Mile Island in Pennsylvania and the catastrophic explosion at Chernobyl in 1986 brought a halt to any thought of expanding nuclear technology in the United States.

The forecasts agreed that no nuclear plants would be built prior to 2020. But with the new energy law and the strong government support for nuclear energy, it is likely a new plant could be on line shortly after 2015.

A great climate for renewables but they won't fill the gap

Currently, non-hydro renewable sources make up about 2 percent of the United States' generating portfolio of 770,000 megawatts. Platts Research, however, says that the potential residential demand within three to four years in markets where green energy is offered could be 6 percent—provided that renewables are marketed effectively. Roughly 6,740 megawatts of wind power is installed in 30 states around the country.

The use of grid-connected generators using renewable fuels are projected to remain minor contributors to North American electricity supply but significant increases in electricity generation from both wind and geothermal power is expected. Record fuel prices and have made wind the world's fastest growing energy source.

The states push hard for renewable energy

US capacity is growing 30% a year. Absent a strong federal policy, states are setting their own standards. One third of the fifty states in the US have adopted renewable portfolio standards (RPS). An RPS is a mandate from state regulators which states that a certain percentage of the state's electricity must come from renewable sources by a certain date.

For example, the Texas electric restructuring law of 1999 required an additional 2,000 megawatts of renewable generating capacity in Texas by 2009. Developers have added 1,190 megawatts on-line since the law was passed, and projects adding 486 megawatts are either under construction or have been officially announced.

In California, the market for new renewable energy forms has increased since legislators there mandated power companies to generate 20% of their energy from green sources by 2017. And New York Gov. George Pataki proposed standards that would ensure at least 25% of the electricity purchased in New York by 2013 is generated from renewable sources. Similarly, Nevada passed a law that says by 2013, utilities there must generate 15% with renewables. The Bureau of Land Management there expects wind and geothermal production to double in the next three years because of the new law. In New Mexico, 5% of utilities' energy portfolios must come from green sources by 2006 and 10% by 2011. The costs can be passed on to consumers.

The lack of transmission capacity to bring the electricity generated from remote locations to residential sections is daunting. In the Midwest, for example, the wires are nearly loaded when carrying 56,000 megawatts fueled by natural gas, coal and nuclear plants. Upgrades are obviously necessary if more renewable power is to be used by utilities in the area.

Despite the favorable climate, renewable technologies will account for just over 5% of expected capacity expansion by 2025—primarily wind and biomass units. Distributed generation, mostly gas-fired microturbines, is expected to add just over 12 gigawatts and will not be a factor during this forecast period. . Total renewable generation in AEO2005, including combined heat and power generation, is projected to grow from 359 billion kilowatt-hours in 2003 to 489 billion kilowatt-hours in 2025, increasing by 1.4% per year.

Of all of the alternative energy areas, the one that is the furthest along economically and has strong growth prospects is the wind business. There is about 7,000 megawatts of capacity installed currently in the US representing less than 1% of total US peaking capacity from all sources. Wind electricity costs about $0.04 to $0.06 a kilowatt-hour. Wind electricity right now is highly competitive when compared to natural gas-fired generation. Wind development is aided by a federal production tax credit which gives an incentive of about $0.019 a kilowatt hour to wind developers. This federal tax credit has expired in the past and been reinstated and the energy bill extended it through 2008.

Although wind will still be only a marginal percentage of generation by 2010 representing less than 2% of total electric generation, it will continue to gain momentum and grow to as much as 5% by 2020. American Wind Energy Association has said that about 2,500 megawatts of new wind power capacity will be installed this year, bringing total U.S. wind capacity to more than 9,200 megawatts. WEA's director Randall Swisher said the industry is hopeful to maintain record growth rates, particularly after Congress extending the wind energy production tax credit through December 31, 2007. By then U.S. wind power capacity should grow 52% to 14,000 megawatts, according to AWEA.

The Energy Policy Act of 2005 Embraces the Past

Historically, U.S. Energy policy has been a collection of mandates and subsidies that steer people towards one source of energy or another. No better example of this process is the recently expanded mandate for ethanol usage. Another example is last year's energy bill.
Sky rocketing oil and natural gas prices gave new momentum to Congressional deliberations and on July 26, 2005 the House-Senate Conference Committee reconciled their differences and reached agreement on the Energy policy Act of 2005 which President Bush signed. The legislation streamlines regulatory procedures for LNG terminal siting, provides subsidies, tax incentives to promote efficiency, clean coal, nuclear and renewable power. In general, the legislation fails to substantially modify current energy demand or domestic supply trends.

Critics of the bill say it falls far short of what the nation could accomplish and does nothing to force changes in automotive fuel consumption. The bill does direct the president to find ways to reduce overall consumption by one million barrels of oil a day by 2015, but the Senate rejected a broader goal of reducing oil imports by 40 percent within 20 years. Senators also rejected efforts to require limits on emissions believed to contribute to global warming. In general, the bill fails to substantially modify current energy demand or domestic supply trends.

Opening the Outer Continental Shelf

More than 85% of the OCS is unavailable to energy development. Currently, federal offshore drilling is allowed in only four states: Alaska, Alabama, Louisiana and Texas. The recently passed Energy Policy Act of 2005 requires Mineral Management Services (MMS) to conduct a comprehensive inventory and analysis of the oil and natural gas resources for all areas of the OCS. Governor Bush and the Florida delegation helped remove a provision that would have relaxed leasing moratoriums for gas making Florida an ideological battle ground between those who recognize it is the federal government which owns these resources and some coastal states which claim the right to block such activities. The MMS announced in a notice in the Federal Register on August 24, 2005 that it is soliciting comments through October 11, 2005, on the development of its 5-year leasing plan for energy development on the Outer Continental Shelf (OCS) and accompanying environmental impact statement.

The announcement is the first step in a 2-year process to develop the leasing plan, and the public is asked to comment not only on energy development, but also on other economic and environmental issues in the OCS area. The MMS is also asking the public to comment on whether the existing moratoria should be modified or expanded to include other areas of the OCS. According to the MMS, the OCS contains billions of barrels of oil and trillions of cubic feet of natural gas.

A WORD ABOUT MEXICO

Like the US, Mexican gas demand will be driven by electricity generation and will increase 10% a year for the foreseeable future reaching over 40% of demand by 2010 (about 3.5 bcfd). Half of Mexico's electric power currently is generated from oil and plans call for most power plants built in the future to run on natural gas.

Since 1998 domestic production has been flat and only 10% of the potential resource base has been explored. Accordingly, Mexico's demand for natural gas has outpaced the country's production over the last decade. Unfortunately, the state company PEMEX does not have the budget to explore offshore and cannot provide these supplies. PEMEX is hobbled by a shortage of investment funds as the government collects 60 cents of every dollar in sales causing PEMEX to lose money every year since 1998. Institutional and ideological concerns have led to laws and regulations that blocked private capital and participation. Lacking capital and technology, PEMEX has been unable to exploit development opportunities. The solution appears to be increased imports from the US (700 mmcfd in 2003) and LNG.

Energy policy has become a point of contention in next years Presidential election with one candidate advocating maintaining government ownership of Pemex, a second advocating privatizing Pemex and launching alliances with domestic and foreign producers, and the third arguing that Pemex should be open to private Mexican only investors. Pemex did receive $10 billion of relief in the recent tax law reforms, but still will lack the funds to develop new reserves.

Revisiting the Gas Demand Forecasts

As noted earlier, many of the key assumptions contained in the IEA, EIA and other forecasts have been challenged by many industry representatives and explored extensively in this survey. These concerns and challenges to the demand forecasts for gas fired generation can be summarized in a series of questions concerning price, supply, the future competitiveness of natural gas vis-à-vis other fuels, the direction government policy will push fuel users and the impact the slowing of market reforms will have on the choice of generation. Although the answers to these questions may not materialize for several years, they accurately frame the debate over whether or not North America will undergo a fuels revolution in the next decade:

<u>The Price Forecasts</u>:

- Is there a significant risk that the EIA and other forecasts are wrong about future natural gas prices?
- Is a range of $4.50 to $5.50 mmbtu really a competitive price? Some utilities argue that coal is competitive at $3.50 and an economic opportunity at $4.50.
- What price is a "show stopper?"
- Considerable infrastructure will be needed to access the new production areas and LNG supplies. Have the costs of these new facilities been incorporated in the projected burner tip price projections?

<u>The Supply Outlook</u>: The price forecasts are based on a considerable increase in supplies from LNG, the Rocky Mountains and other frontier and non conventional areas (McKenzie Delta, CBM, western Alberta, tight sands).

- <u>Rocky Mountains</u>: producers argue that meeting the supply forecasts is only a matter of opening up new federal lands for exploration. Will the American public support opening up new drilling areas and eradicating environmental restrictions and other impediments to production in this area (and the offshore)?
- Can a case be made that future production from this area is over estimated considering that only 16% of the oil and 12% of the natural gas prospects are really unavailable?

- <u>LNG:</u> is the forecast of 8-10 new terminals by 2010 realistic? Will there be adequate supplies for the new terminal capacity?

- If most of the terminals are built on the gulf coast, what will be the price impact at Henry Hub? Will prices be depressed affecting the economics of LNG? Of unconventional gas production? Or will a flood of LNG supplies have a minimal impact on domestic prices because of steeper than predicted domestic production declines? Which view is reasonable?

- <u>Canadian supplies</u>: most forecasts show flat exports to 2010 and a slow decline after 2010. Are we underestimating the potential decline in Canadian exports? Some argue demands of the Kyoto Protocol and increased tar sands production will accelerate gas demand in Canada and supplies such as in the McKenzie delta will never leave Canada. Is this a reasonable view?

<u>Competitiveness</u>:

- In this high price environment, will the environmental advantages, lower construction costs and shorter lead times still be enough to maintain a competitive advantage for gas against coal at gas prices that could exceed $5.50 mmbtu?

- Will there be further improvements in IGCC technology that could impact generation choices during this time period?

Government policy: the increase in gas power demand is also predicated on tougher environmental polices regarding CO2 and mercury increasing the cost of using coal.

- Are we over estimating the impact of these new environmental regulations on coal use? Can't many of these costs easily be absorbed into a rate based coal plant?
- Is it reasonable to expect that a Congress and administration that has made it clear it supports increased coal use would implement a series of regulations to penalize coal use? How will the changes in New Source Performance Standards affect coal generation growth in the next five years? What other incentives will the government give the coal industry? Will government policies push generators towards coal and nuclear?

Market structure: predictions are being made about gas fired generation will little thought to what form the generation will take and how it will be integrated into the power market.

- In the past, merchant plants have accounted for the vast majority of new gas-fired generation. Is it reasonable to assume that in this volatile and high priced environment merchant plants are an option?
- If new gas plants require long-term contracts including pass through of fuel risk for financing, why not build rate-based plants? If this occurs, aren't we putting the generation decisions in the hands of the very people (utilities) who have the ability to finance and build coal plants?

CONCLUSIONS

Key Points:

- **The North American power industry faces a quandary.** Uncertainty over the timing and magnitude of LNG supply additions, compounded by the electric power industry's greatly increased reliance on natural gas, have created an unprecedented set of risky alternatives for power utility managers and regulators. The forecasted annual electricity demand growth of between 1.1% and 2.4% per year will require 20% to 40% more electric generation capacity by 2020. Key to meeting this growth target will be the full utilization of the gas-fired generation built in the last decade which when added to new gas-fired capacity will require natural gas markets to expand between 14% and 36% by 2020.

- **But on the supply side, US gas production is stagnating having reached its highest production level in 2001.** There are massive volumes of gas that still remain locked in domestic reservoirs, primarily tight gas sands, gas shales, and coiled methane basins. In addition, deep gas resources, onshore and offshore, remain undeveloped. Eight of the top twelve gas fields in the US are now unconventional fields. More-advanced knowledge and improved technology are increasing recovery rates from unconventional gas reserves. Although a surge in drilling and new production may briefly reverse high gas prices, it will be difficult to sustain domestic production over the longer-term.

- **While North American drilling activity has been very high and short-term production has responded, depletion rates on existing fields are accelerating.** North American drilling activity and new production has to accelerate simply to hold overall North American output constant. If gas prices were to drop to levels where the value of aggressive drilling became marginal, North American gas production would quickly decline and gas prices would again soar.

- **Historically, Canadian imports have bridged the gap between supply and demand with imports increasing from 2.2 tcf in 1997 to 3.2 tcf in 2003.** But Canadian production may have peaked in 2002 and new sources of gas from Alaska and the Canadian Artic may not be accessible for ten years. Disagreements over which pipeline should be built and the actual time to construct and bring into operation these multi billion dollar projects indicate it may be later than sooner. New sources of supply other than Alaska and Canada will be needed.

- **LNG is the source of new supply with the greatest potential.** Although predicted by EIA to increase to 8 percent by 2010, it will depend on whether facilities can be built to gasify, store and move the supplies into the interstate system in a timely manner. In many parts of the country, siting and construction of new LNG reception facilities is proceeding slowly due to local opposition. Passage of federal legislation should help. Future LNG supplies in North

America are critical in all scenarios for future electric power generation. With a permanent shift to higher natural gas demand levels, utilities' primary avenue for assuring adequate supply and managing price volatility will be to acquire alternative supplies of LNG.

- **2005 to 2010 will be a critical period for U.S. LNG projects and LNG will need to make up 12% of the total energy mix to make up a supply shortfall of 10.5 bcfd.** Some believe that the forecasters have ignored the world competition for LNG as other industrialized and rapidly industrializing countries scramble to sign LNG contracts and build facilities. Demand is growing in Europe and Asia.

  Two years ago the US had a price advantage but that is disappearing with the rise in oil prices. U.S. prices of natural gas hovered around $6 million Btu and import prices of LNG in Europe ranged between $2 and $4 mmbtu, and those in Japan and Korea between $3 and $5 mmbtu. Estimates of production and delivery costs of LNG to North America appear to hover around $3 mmbtu. The IEA expects the Atlantic Basin to account for two thirds of global energy trade in LNG.

- **The price impact of LNG imports is also a wild card impacting the energy mix.** A recent Morgan Stanley report boosted the outlook for US gas prices due to higher finding costs and higher prices for important substitutable for natural gas. Their analysts' team contends that the finding and development costs over past decade have doubled and that gas producers require $40 oil and $6 natural gas to earn comparable returns to cover overhead and exploration costs as compared to years when oil averaged $30 a barrel and gas $3 mmbtu. Some are concerned that a flood of LNG will collapse domestic prices. The downward pressure would hit unconventional production especially hard. Lehman Brothers[26] say that domestic gas production is declining at 2-3.5% annual rate and that LNG imports will displace the highest cost domestic gas production.

- **Most maintain that globally there will be a relationship between oil and gas long-term and it is unlikely that gas will sell at an mmbtu discount to oil.** Others see the Henry Hub or New York Mercantile Exchange being the benchmark for world LNG sales. Since the beginning of 2006, the drivers of natural gas pricing have now changed from an environment based on extreme fear of storage shortfalls during the heating season and near-crisis conditions along the Gulf Coast to one predicated on typical Btu-equivalence with substitutable refined products and the return of more normal basis discounts across the country.[27]

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[26] Lehman Bros. Equity Research. April 7, 2005. Thomas Driscoll, Sangita Jain. Their estimates for price requirements are $45 bbl oil and $6.25-$6.50 mmbtu for gas to earn a pretax profit of 15%.

[27] On a Btu-equivalent basis crude oil (in barrels) should be about six times the price of natural gas (in million Btu). In late November, the ratio was about 5:1 (e.g., $58 oil to $11.50 gas). In December, as gas spiked to $15/mmBtu, the ratio dropped as low as 4:1. The ratio now is roughly 6.7:1 (e.g., $64 oil to $9.50 gas). Natural gas is thus about 25% less expensive relative to oil than in late November. In terms of key refined products that compete with gas, especially #2 heating oil and #6 residual oil, natural gas is now in the traditional relative price range.

- **Casting a shadow over the fuel mix are environmental concerns.** Addressing environmental and related political issues will, in general, increase the demand for natural gas (further driving up its price) and make coal more expensive to use. No matter how implemented, policies aimed at reducing emissions of sulfur dioxide, nitrogen oxides, particulates, mercury, and carbon dioxide will have the unavoidable long-term effect of increasing the demand for natural gas and increasing the cost of using coal.

- **This is not to say environmental risks can't be managed.** The recent settlement between Xcel Energy and Environmental Groups in Colorado is instructive and may give insight on potential coal use even with environmental add-ons. [28]

- **Coal and nuclear appear to offer stable prices and long-term supplies.** Some level of new coal-fired power generation is part of all scenarios because differentials between coal and natural gas prices and a preference for secure domestic energy sources make new coal plant construction attractive, especially in coal-conducive states and provinces even under a scenario with very stringent environmental rules. A CERA analysis found that it is possible that, between 2010 and 2015, newly added coal-fired generation could offset the need for as much as 5 bcfd of natural gas used for power generation, or up to one-tenth of all the gas produced in the Lower 48 states and the equivalent of the output of five large LNG regasification plants. The coal-fired generation capacity that could be added by 2020 is expected to be located in the central U.S.—particularly in areas with existing coal industries and large coal fleets, and almost none in coastal regions.

- **Significant risks regarding natural gas prices, project cost, and uncertainty surrounding costs associated with carbon emissions suggest that regulated, municipal, or cooperative utilities or companies with firm power sale contracts are the best positioned coal generation developers.** Merchant plants will be at a severe disadvantage not only because of high gas prices but because of the desire of public utility commissions to avoid supply shortages and control generation. Utilities are in the drivers' seat.

- **Barring major security threats that could cause nuclear plants to close, the existing nuclear fleet will continue to operate and expand modestly through capacity creep and perhaps one new plant by 2015.** The potential for new nuclear construction is premised on the desire for greater fuel diversity and concerns about greenhouse emissions.

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[28] Xcel has proposed building two new 750 megawatts of coal-fired units located in Pueblo Colorado. Xcel operates two existing units at 350 megawatts each which are uncontrolled for SO_2, NO_x and particulate emissions. The new plants faced fierce opposition from environmental and community groups. As part of a settlement, Xcel agreed to clean up the two existing plants including mercury reductions, invest $196 million in demand side management during 2006 and 2013, accept all cost competitive wind resource bids up to 15% penetration based on system peak demand, and in evaluating the costs of new CO_2 emitting resources, assess an imputed $9/ton cost in the competitive bid solicitation process. Xcel agrees that if any such tax is enacted after a power purchase contract is signed, they will be responsible for the added costs.

- **Over the long-term, dollars will increasingly be attracted to investing in generating technologies that use low-cost fuels.** This no doubt will include new clean coal technologies, possibly super-critical pulverized coal units, and advanced nuclear reactors, some of which have already been certified by NRC. The rise in share price of utilities and power generators with large investments in coal and nuclear assets, and the bidding up in price of nuclear units going to auction, may be harbingers of this long-term trend. Clean coal is already 20% more expensive than conventional pulverized coal but with the loan guarantees and production credits in the energy bill will get the first commercial plant built.

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