STATEMENT OF

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before the

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Mister Chairman and Members of the Committee:

I appreciate the opportunity to appear before you today to discuss the outlook for natural gas supply and prices in the United States.

The Energy Information Administration (EIA) is the statutorily chartered statistical and analytical agency within the Department of Energy. We are charged with providing objective, timely, and relevant data, analysis, and projections for the use of the Department of Energy, other Government agencies, the U.S. Congress, and the public. We do not take positions on policy issues. We produce data and analysis reports that are meant to help policy makers determine energy policy. Because we have an element of statutory independence with respect to the analyses that we publish, our views are strictly those of EIA. We do not speak for the Department, nor for any particular point of view with respect to energy policy, and our views should not be construed as representing those of the Department or the Administration. EIA's baseline projections on energy trends are widely used by Government agencies, the private sector, and academia for their own energy analyses.

The projections in this testimony are from the February 2003 *Short-Term Energy Outlook* (STEO) and the *Annual Energy Outlook 2003* (*AEO*). These projections are not meant to be exact predictions of the future, but represent a likely energy future, given technological and demographic trends, current laws and regulations, and consumer behavior as derived from known data. EIA recognizes that projections of energy markets are highly uncertain, subject to many random events that cannot be foreseen, such as weather, political disruptions, strikes, and technological breakthroughs. (Many of these uncertainties are explored through alternative cases.)

The AEO is based on data available through September 2002; the STEO projections reflect more recent data. As a result, the short-term projections in the AEO and the February STEO do not necessarily match.

Overview and Assumptions

EIA's *Short-Term Energy Outlook* is a monthly forecast report that addresses a wide range of issues in energy markets. The forecast has a 2-year horizon, based on simulations of EIA's Short-Term Integrated Forecasting System (STIFS), incorporating the latest exogenous information available. The historical energy data are mostly EIA data regularly published in other EIA publications. STIFS is driven principally by three sets of assumptions or inputs: estimates of key macroeconomic variables, world oil prices, and weather. Macroeconomic estimates are produced by Global Insight (formerly DRI/WEFA) but are adjusted by EIA to reflect our own assumptions about the world price of crude oil, energy product prices and other factors, which may affect the macroeconomic outlook.

The *Annual Energy Outlook* is produced using the National Energy Modeling System (NEMS), a computer-based, energy-economy modeling system of U.S. energy markets through 2025. NEMS projects annual production, imports, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. Two of the key assumptions in NEMS are world oil prices and macroeconomic growth.

World oil prices averaged about $23.15 per barrel in 2002 in 2001 dollars. Between now and 2025 they are expected to rise to about $26.60 a barrel in 2001 dollars, as world oil demand increases from 76 million barrels per day to 123 million barrels per day. In 2003 real gross domestic product (GDP) is projected to grow by 2.8 percent over 2002 and to grow at an annual average rate of 3.0 percent between 2001 and 2025.

Short-Term Natural Gas Outlook

Over the last twelve months the U.S. natural gas market has tightened significantly as principal demand and supply factors have worked to swing market conditions from being oversupplied (excess storage) to being relatively undersupplied (low storage). An approximate doubling of average spot prices has ensued. Strong underlying domestic demand for natural gas has been boosted by short-term or cyclical factors (including weather and oil market shifts) while domestic natural gas resource development efforts have faded relative to the spectacular levels of activity seen in 2001.

A salient feature of the contrast between U.S. natural gas market conditions in 2003 and those during 2002 is the dramatic difference in the availability of natural gas in storage as a cushion between strong demand growth and (at least somewhat) less robust gains in domestic production and other new supply. Steady pressure on wellhead supply from strong demand, stemming from weather-related factors, spillover from tight oil markets, and expected growth from the industrial and electric power sectors, is expected to keep domestic natural gas prices high in 2003 and at risk for significant volatility through at least the next 12 to 18 months. Expected strong levels of domestic natural gas drilling and development should provide increases in gross productive capability through 2004 but increases in pipeline capacity will be needed to insure maximum growth in effective deliverability. Thus, the expected average wellhead price this year is $4.35 per thousand cubic feet in current dollars and $4.27 next year, compared to $2.95 last year.

Natural Gas Outlook to 2025

By 2025 total natural gas consumption is expected to increase to almost 35 trillion cubic feet (Tcf) or 26 percent of U.S. delivered energy consumption (Figure 1).

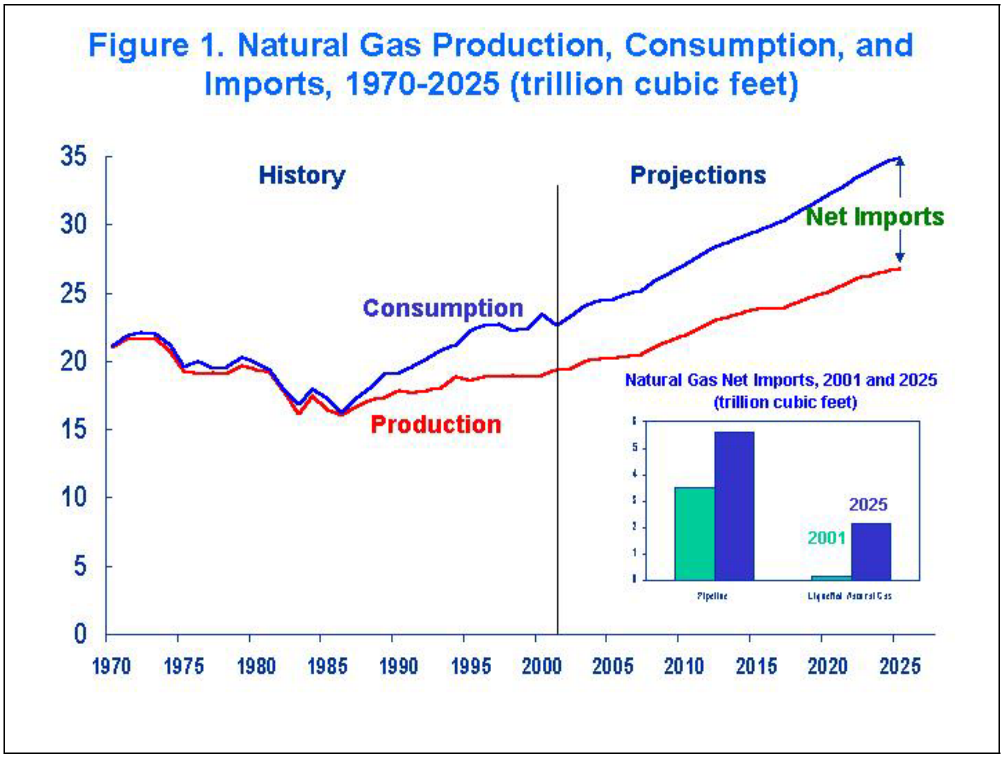


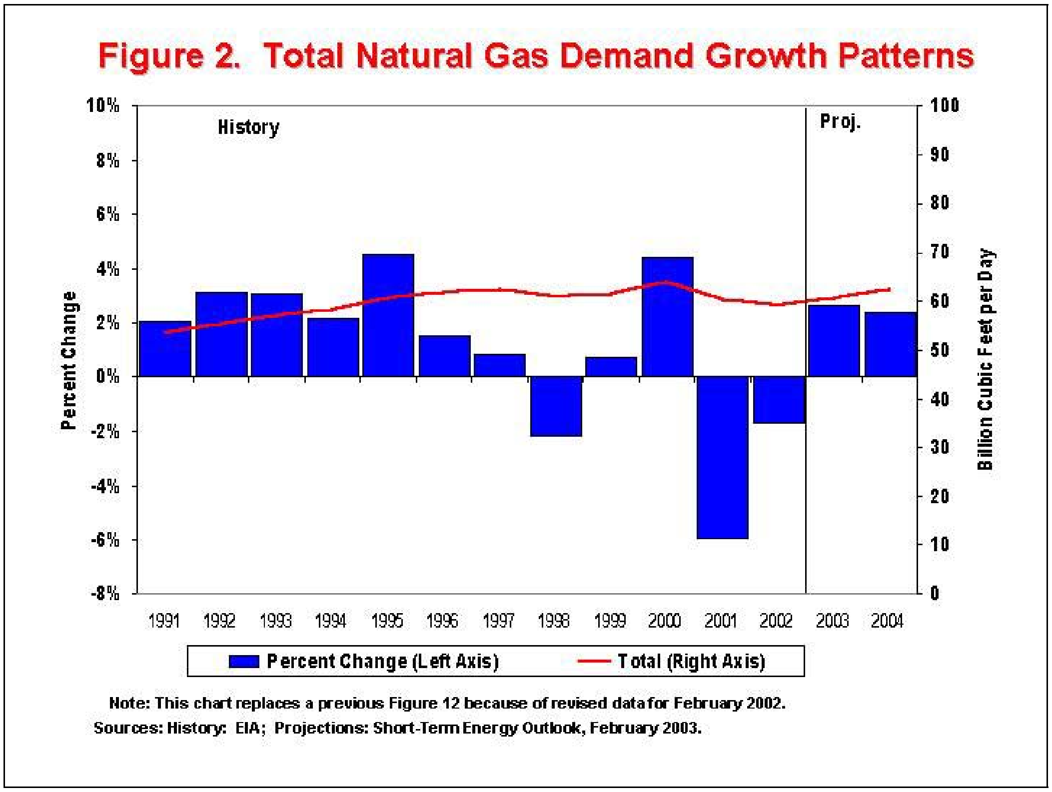
Figure 1. Natural Gas Production, Consumption, and Imports, 1970-2025 (trillion cubic feet)

Domestic gas production is expected to increase more slowly than consumption over the forecast, rising from 19.5 Tcf in 2001 to 26.8 Tcf in 2025. Growing production reflects increasing natural gas demand and is supported by rising wellhead gas prices, relatively abundant gas resources, and improvements in technologies, particularly for unconventional gas. In this forecast, economic conditions allow an Alaskan pipeline to begin moving gas to the lower 48 States in 2021. The national average wellhead price is projected to reach \$3.90/Mcf in 2001 dollars by 2025.

The difference between consumption and production is made up by increasing use of imports throughout the forecast, particularly from liquefied natural gas (LNG), with a 2 Tcf increase expected over 2001 levels. By 2025 we expect expansion at the four existing terminals and construction of three new LNG terminals.

Consumption. Total natural gas demand in 2002, based on data reported through September, declined by 1.4 percent from the 2001 level. Overall weakness in the industrial sector, particularly in the first three quarters of the year, prevented a posting of positive growth. However, solid growth in natural gas demand is likely in 2003, especially if the industrial sector as a whole expands significantly as expected (Figure 2).

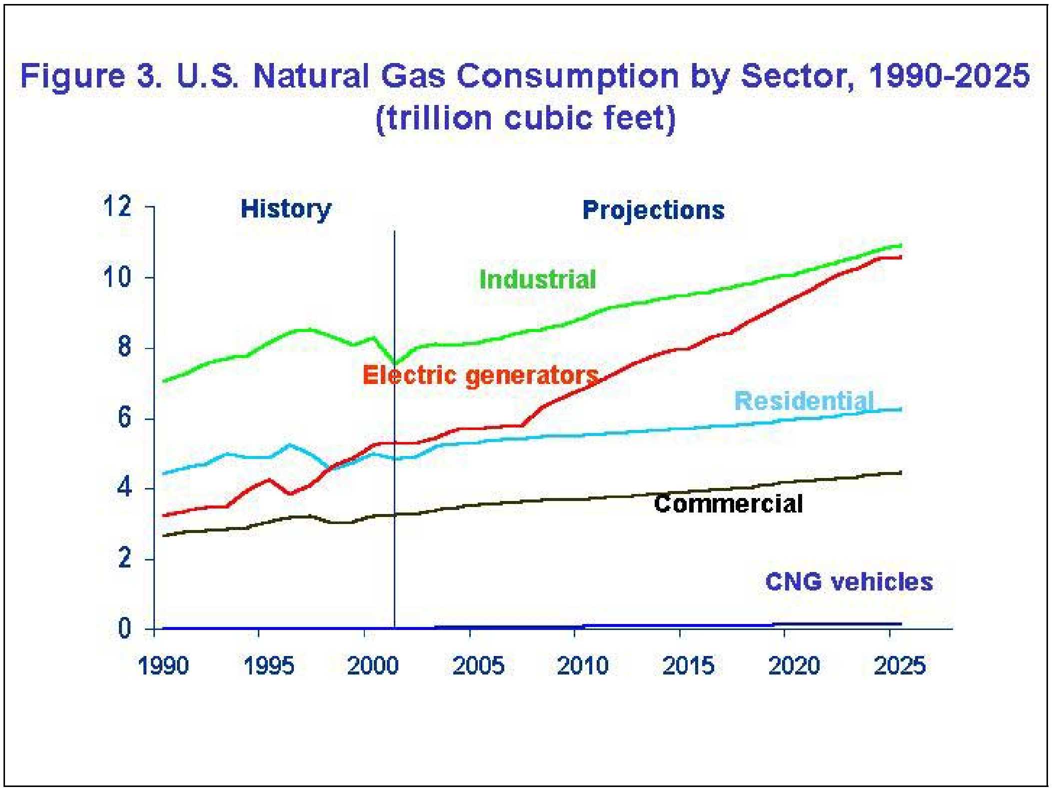
In 2004, natural gas demand is projected to rise by an additional 2.4 percent as industrial demand continues its recovery from its 2002 lows.



Natural gas demand this winter (fourth quarter 2002 and first quarter 2003) is expected to be about 8 percent above last winter's demand, largely due to the fact that gas consumption-weighted heating degree-days will be 11 percent above year ago levels, provided February and March post normal temperatures.

U.S. natural gas consumption is expected to increase by 1.8 percent annually from 2001 through 2025. Gas consumption by electric generators is expected to double over the forecast, from 5.3 Tcf in 2001 to 10.6 Tcf in 2025, an average annual growth rate of 2.9 percent (Figure 3). Demand by electricity generators is expected to account for 30 percent of total natural gas consumption in 2025.

Most new electricity generation capacity is expected to be fueled by natural gas, so natural gas consumption in the electricity generation sector is projected to grow rapidly throughout the forecast as electricity consumption increases. Although average coal prices to electricity generators are projected to fall throughout the forecast, gas-fired generators are expected to have advantages over coal-fired generators, including lower capital costs, higher fuel efficiencies, shorter construction lead times, and lower emissions.



Historically the industrial sector, excluding lease and plant fuel, is the largest gas-consuming sector, with significant amounts of gas used in the bulk chemical and refining sectors. Industrial consumption is expected to increase by 3.4 Tcf over the forecast, driven primarily by macroeconomic growth. The chemical and metal durables sectors show the largest growth.

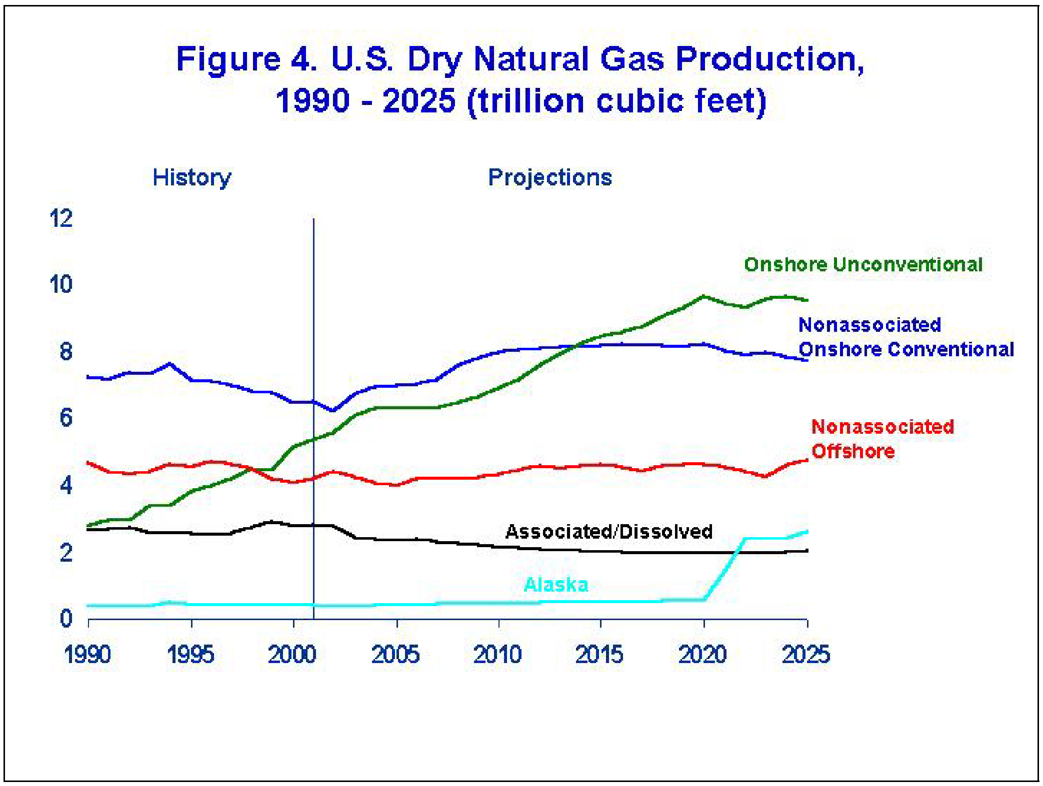
Combined consumption in the residential and commercial sectors is projected to increase 2.6 Tcf from 2001 to 2025, driven by increasing population, healthy economic growth, and gradually rising prices in real terms. Natural gas remains the overwhelming choice for home heating throughout the forecast period, with the number of natural gas furnaces rising nearly 18 million.

Production. New data provided to EIA by the Minerals Management Service on natural gas production in the Federal Offshore Area of the Gulf of Mexico has resulted in a revised view of total domestic natural gas production for 2002. It is now estimated that U.S. dry natural gas production fell by 450 billion cubic feet (Bcf) (2.3 percent) in 2002 from the 2001 total. At least moderate production increases are expected in 2003 and 2004 as high natural gas prices and strong near-term demand pressures drive drilling activity and well completions to very robust levels over the period. Monthly domestic oil and gas lease revenues, which averaged about $280 million in 2002, are expected to reach the $400 million mark in 2003 and remain near that level in 2004.

The forecast estimate of total technically recoverable natural gas resources as of January 1, 2002, was 1,289 Tcf. These resource assessments come primarily from the assessments done by the U.S. Geological Survey for onshore regions and by the Mineral Management Service for the offshore.

These resources included 183 Tcf of proved reserves (9 years of consumption at 20 Tcf per year), 222 Tcf of inferred reserves, and 269 Tcf of undiscovered nonassociated conventional resources. The largest category was unconventional resources at 445 Tcf, with most of that in tight sandstones at 71 percent. Other unconventional natural gas resources include gas shales and coalbed methane. Alaska gas (32 Tcf) and associated-dissolved natural gas in lower 48 crude oil reservoirs (137 Tcf) round out the resource.

Increased U.S. natural gas production through 2025 comes primarily from unconventional sources and from Alaska (Figures 4&5). Unconventional gas production increases by 4.1 Tcf over the forecast period—more than any other source, largely because of expanded tight sands gas production in the Rocky Mountain region. Annual production from unconventional sources is expected to account for 36 percent of production in 2025, more than any other source, compared to 28 percent today.

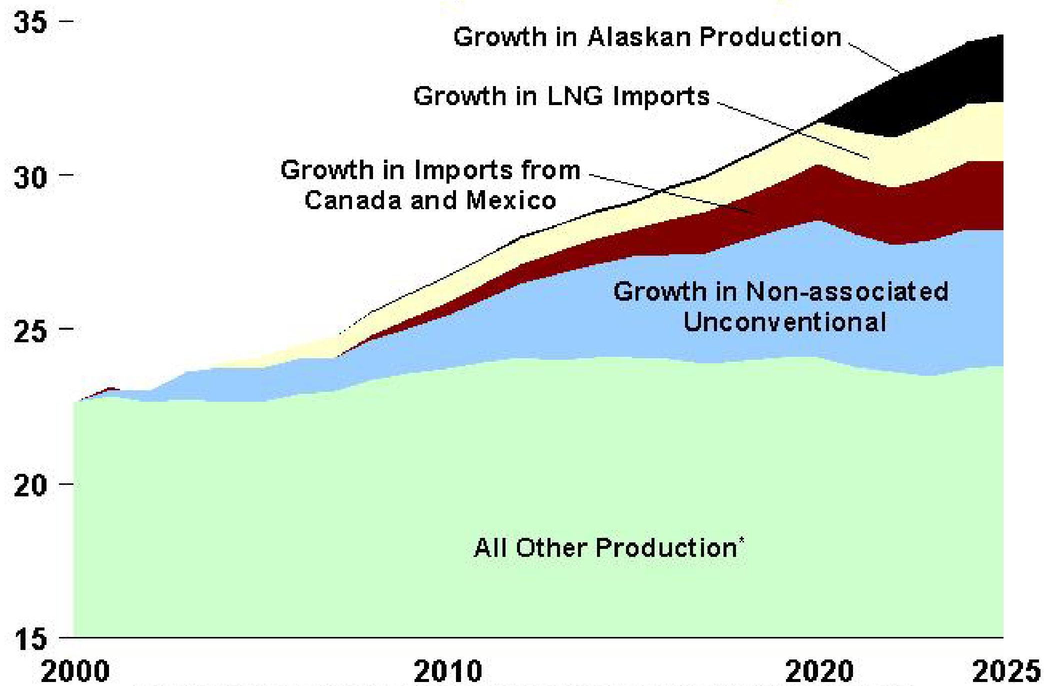


An Alaska natural gas pipeline begins flowing gas to the lower 48 States in 2021, reaching 4.5 billion cubic feet (Bcf) per day in 2023, with further expansion beginning in 2025 (Figure 5). Alaska also continues to provide for consumption in the State itself and for LNG exports to Japan. In 2025, total Alaskan gas production is projected to be 2.6 Tcf.

Conventional onshore non-associated production increases by 1.2 Tcf over the forecast, driven by technological improvements and rising natural gas prices. However, its share of total production declines from 34 percent in 2001 to 29 percent by 2025. Non-associated offshore production adds 560 Bcf, with increased drilling activity in deep waters; however, its share of total U.S. production declines from 22 percent in 2001 to 18 percent by 2025.

Associated dissolved production declines by 800 Bcf, consistent with a projected decline in crude oil production. Lower 48 associated-dissolved natural gas is projected to account for 8 percent of U.S. natural gas production in 2025, compared with 15 percent in 2001.

Figure 5. Major Sources of Incremental Natural Gas Supply, 2000-2025 (trillion cubic feet)



*Includes total associated-dissolved, non-associated conventional, lower-48 offshore, and Supplemental natural gas production. Also includes 2001 Canadian, Mexican, and LNG imports and Alaskan and non-associated unconventional production.

Depletion. A key question facing producers and policymakers today is whether natural gas resources in the mature onshore lower 48 States have been exploited to a point at which more rapid depletion rates eliminate the possibility of increasing—or even maintaining—current production levels at reasonable cost.

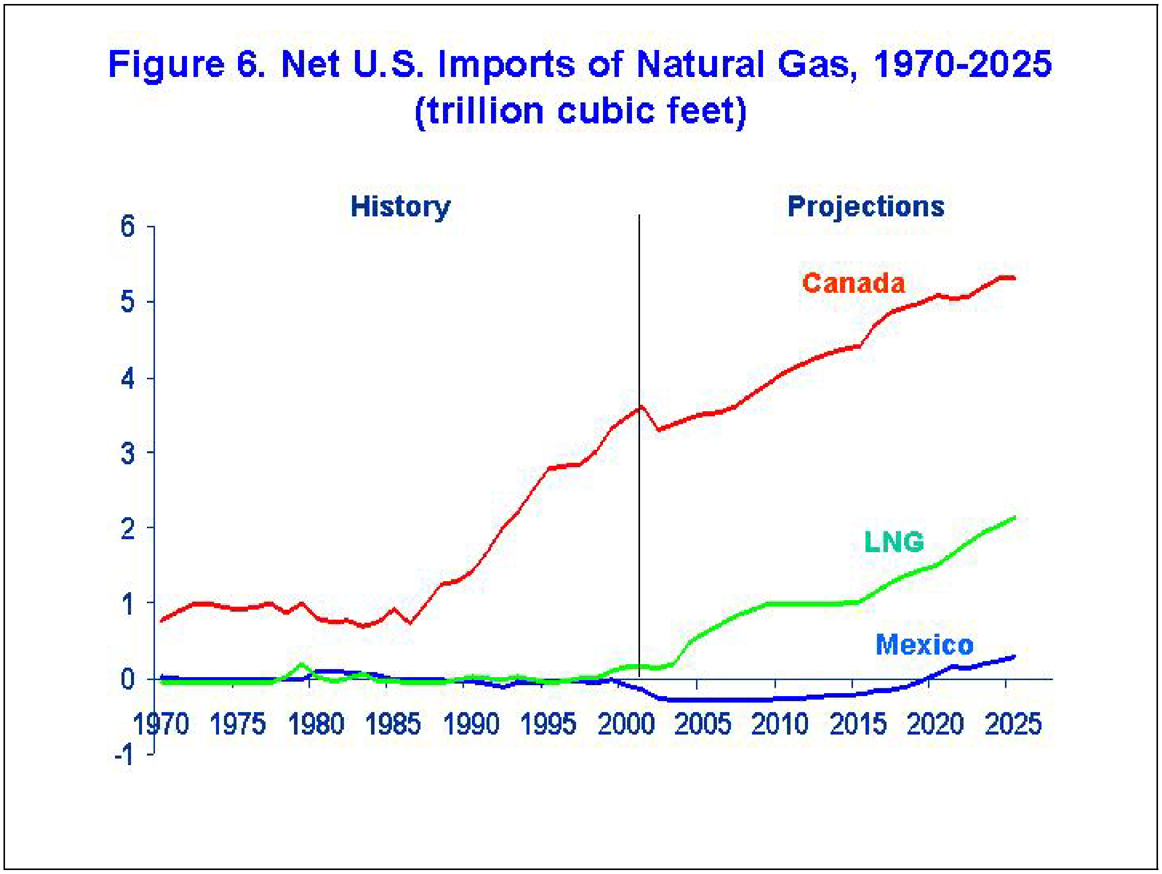
Depletion is a natural phenomenon that accompanies the development of all nonrenewable resources. Physically, depletion is the progressive reduction of the overall volume of a resource over time as the resource is produced. In the petroleum industry, depletion may also more narrowly refer to the decline of production associated with a particular well, reservoir, or field. As existing wells, reservoirs, and fields are depleted, new resources must be developed to replace depleted reservoirs.

Depletion has been counterbalanced historically by improvements in technology that have allowed gas resources to be discovered more efficiently and developed less expensively, have extended the economic life of existing fields, and have allowed natural gas to be produced from resources that previously were too costly to develop. In *AEO2003*, technological progress for both conventional and unconventional recovery is expected to continue to enhance exploration, reduce costs, and improve production technology.

The depletion of conventional and unconventional natural gas resources is expected to continue over the projection period as the demand for natural gas increases significantly, continuing the trend that began in the mid-1990s. Nevertheless, with sustained wellhead prices generally over $3 per thousand cubic feet (in 2001 dollars) and continued technological improvements, lower 48 nonassociated gas production is expected to increase above current levels.

Imports. The difference between U.S. natural gas production and consumption is net imports. After growing by an expected 1.1 percent in 2002 due to high stocks and lower demand, natural gas net imports are expected to increase by 5.6 percent in 2003, which should relieve some of the potential pressure on the domestic market.

Net imports of natural gas, primarily from Canada, are projected to increase from 3.7 trillion cubic feet in 2001 to 7.8 trillion cubic feet in 2025 (Figure 6). Imports contributed 16 percent to total natural gas supply in 2001, compared to an expected 22 percent in 2025.



Almost half of the increase in U.S. imports is expected to come from LNG. Much of the increase comes from expansion at existing sites, but three additional facilities are also built to serve Florida and the Gulf States. The three new LNG facilities are expected to have a combined gas delivery rate of 2 billion cubic feet per day. By 2025, LNG imports are expected to equal 6 percent of total U.S. gas supply.

Growth in pipeline imports from Canada partly depends on the completion of the MacKenzie Delta pipeline. The MacKenzie Delta pipeline is expected to be completed in 2016 and expanded in 2023. The initial full flow rate into Alberta is assumed to be 1.5 Bcf per day. Additional imports will come from the Scotian Shelf in the offshore Atlantic. The forecast of Canadian imports largely depends on the ability of Canadian producers to economically produce and market their untapped unconventional resources, particularly coalbed methane. Net imports from Canada are projected to provide 15 percent of total U.S. supply in 2025 in the reference case, about the same as in 2001.

Although Mexico has a considerable natural gas resource base, trade with Mexico has consisted primarily of exports from the United States. Mexico is projected to go from a net importer of U.S. natural gas to a net exporter in 2020, as an LNG facility begins operating in Baja California, Mexico, in 2019, predominantly serving the California market. By 2025, the United States is expected to import about 300 billion cubic feet of natural gas from Mexico per year.

Pipelines. The opening of an Alaskan natural gas pipeline depends on competing natural gas prices in the lower 48 States and Canada, financing, and the degree of difficulty in siting and permitting the pipeline, among other factors. We have assumed that lower 48 wellhead prices must be at least $3.48 in 2001 dollars for 3 years before pipeline construction begins. Construction is assumed to take 4 years. The cost of the pipeline from Alaska to Alberta is assumed to be $11.6 billion in 2002 dollars with a 7.5 percent discount rate, based on a study released last year by the owners of the North Slope gas.[1]

While the pipeline is expected to begin operation in 2021 in the reference case, other assumptions—such as those about macroeconomic growth or the pace of technological change—affect the wellhead natural gas price and thus, the start date of the pipeline. In the slow oil and gas technology case, where the rate of technological improvement is 15 percent slower than the reference case, the flows on the Alaska pipeline start in 2019. In the high economic growth case, which assumes a GDP growth rate of 3.5 percent, the flow starts in 2018. Other factors which could affect the start of an Alaska pipeline are restrictions on carbon emissions and assumptions about the size of the natural gas resource base.

In all of these cases the MacKenzie Delta gas pipeline from MacKenzie Delta to Alberta starts 4 or 5 years before the Alaska pipeline. This $3.6 billion pipeline is assumed to be triggered by a lower 48 States gas price of $3.37. The MacKenzie Delta pipeline is assumed to have an initial flow of 1.5 Bcf per day, a planning period of 2 years, and a construction period of 3 years.

Additional interstate pipeline capacity will be required in the lower 48 States to bring Arctic gas to market, as well as to accommodate the growth in consumption over the forecast. While the flow of gas between primary regions in the lower 48 States is expected to increase by 40 percent from 2001 to 2025, the pipeline capacity necessary to transport this gas is only expected to increase by 26 percent. In order to do so, the annual utilization along these pipeline corridors will need to increase from 63 percent in 2001 to 70 percent by 2025. As electric generators go from a 25 percent share of end-use consumption in 2001 to a 33 percent share by 2025, the annual throughput on pipelines can expect to increase as well, since electric generators are primarily expected to add to either the base load requirements or the off-peak loads.

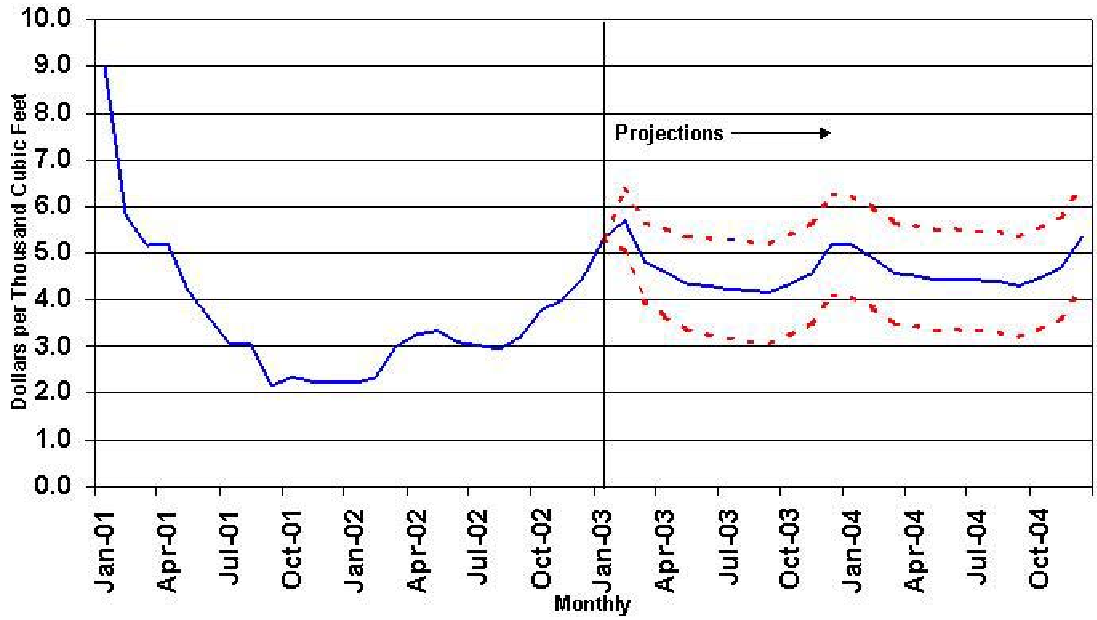
Wellhead Prices. Spot wellhead natural gas prices, which exploded in early 2001 in response to a winter demand surge amid very low inventory levels, retreated to low levels in early 2002 amid very weak winter demand and excess natural gas in storage (Figure 7). The very high short-term prices accelerated a natural gas drilling recovery that originated during the spring of 1999. However, a brewing pessimism in the natural gas market outlook, following a downturn in real GDP, the events of September 11, 2001, falling stock prices, and fallout from the collapse of Enron and other previously high-flying firms stripped some of the enthusiasm from the search for expanded natural gas resources, generating a sharp decline in natural gas-directed drilling by late 2001 and early 2002. Thus, the seeds of resurgence in natural gas prices were sown at the very time that excess supply appeared at its greatest. At the end of February 2002, natural gas in storage was 27 percent above the previous 5-year average; at the end of February 2003,

[1] Additional costs would be incurred to transport this Alaskan gas from Alberta to the lower 48 States.

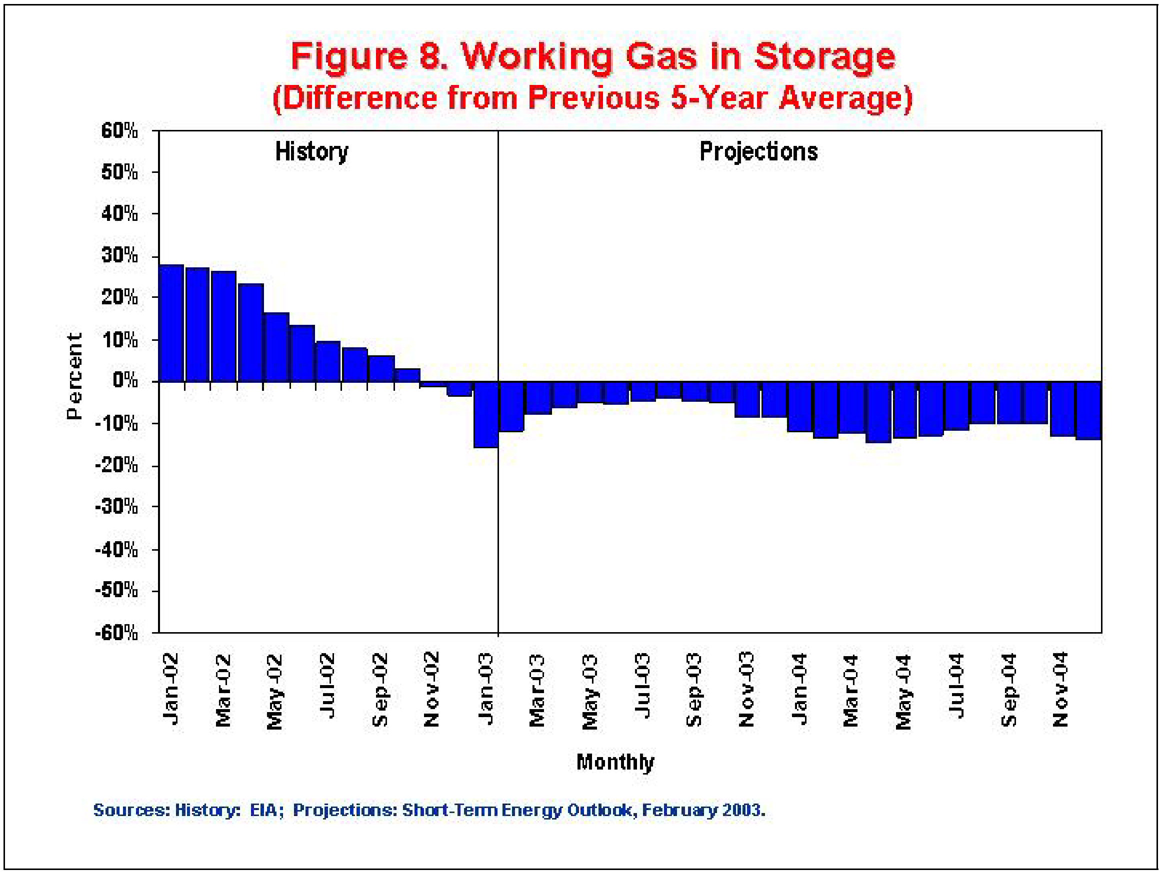
storage is expected to fall 12 percent below the same average. Between those two times, spot prices are expected to post an increase of 151 percent.

Working natural gas in storage fell to about 1.52 trillion cubic feet at the end of January, or about 17 percent below the 5-year average and 35 percent below the year-ago level (Figure 8). January 2001 is the only time since 1977 that the January natural gas working storage level has been lower than this year, although similar end-of-January levels were seen in 1996, 1997, and 1999. However, the current level of gas in storage is relatively low, so full replenishment of working gas stocks in 2003 will be larger than average. The industry's capability to accommodate this requirement without considerable upward price pressure may not be as robust as in earlier years because of other supply factors, such as the possibility that new drilling may be less productive than in the past.

Figure 7. Natural Gas Spot Prices
(Base Case and 95% Confidence Interval)



Sources: History: Natural Gas Week; Projections: Short-Term Energy Outlook, February 2003.



Despite the revised production estimates, a large (1.5 trillion cubic feet) discrepancy remains in the 2002 supply/demand balance. Much of this remaining imbalance relates to underestimated demand, most likely in the industrial sector.

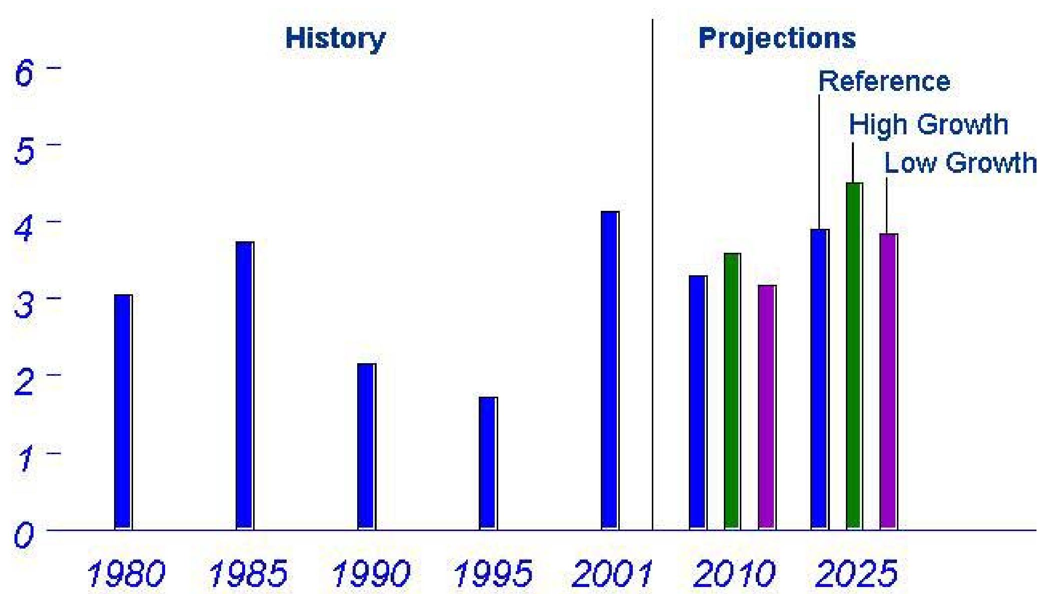
The demand and supply data currently available to describe market developments in 2002 are somewhat contradictory in that the estimated demand growth from 2001 to 2002 appears to be too weak to coincide with the reduction in storage that demonstrably occurred. EIA's current estimate of production changes in 2002, based in part on recently received data from the Minerals Management service, indicates a reduction in new domestic supply of about 2.3 percent from 2001 levels. Other estimates suggest a decline of about 5 percent. Taking either of theses estimates as plausible, the remaining component of market changes that would be required to explain the shift in the gas storage position in the United States in 2002 involves stronger demand than is currently apparent in the data. Since the economy is expected to continue to recover in 2003, particularly in the gas-intensive industrial sector, and since continued tightness in world oil markets is expected to add to natural gas demand strength in the electric power and industrial sectors, continued strength in overall natural gas demand this year is expected.

In contrast to 2002, little or no incremental help from storage to meet new demand is possible in 2003, implying that consistent pressure on wellhead deliverability for natural gas is to be expected unless some of the demand strength is reduced. Therefore, the average wellhead price in 2003 is likely to exceed the 2002 average. The expected average wellhead price this year is $4.35 per thousand cubic feet in current dollars compared to $2.95 in 2002. Weather will, as always, play a key role in market developments for the rest of this year, but assuming normal weather through the forecast leads to the expectation of very strong natural gas spot and average wellhead prices next winter. Natural gas production growth in North America of between 2 and 3 percent, supplemented by increases in imports of liquefied natural gas, will probably be needed to maintain a reasonable balance in the domestic market through 2004. Solid increases in drilling appear likely for 2003 and are likely to provide the needed increase in productive capacity to stabilize the domestic natural gas market at wellhead prices between $3.50 and $4.50 per thousand cubic feet.

In the mid-term, gas prices are projected to move higher as technology improvements and new supply sources prove unable to completely offset the effects of resource depletion and increased demand (Figure 9).

Natural gas prices through 2025 are projected to increase in an uneven fashion as major new, large-volume supply projects temporarily depress prices when initially brought online. Examples include deep and ultra-deep offshore projects in the Gulf of Mexico, unconventional gas (tight sands, coalbed methane, shale), liquefied natural gas facilities (both the expansion of existing and development of new facilities), the MacKenzie Delta pipeline in Canada, and an Alaskan natural gas pipeline that delivers gas supplies to the lower 48 States.

Figure 9. Projected lower 48 natural gas wellhead prices in three cases, 2010 and 2025 (2001 dollars per thousand cubic feet)



In the reference case, average wellhead natural gas prices are expected to increase to $3.90 per thousand cubic feet (2001 dollars) in 2025. The increase reflects rising demand for natural gas and the impact of the progression of discoveries from larger and more profitable fields to smaller, less economical ones. In current dollars, natural gas prices reach $7 in 2025.

An uncertain outlook for the pace of economic growth is one of the key factors that could affect gas prices. Alternative cases were used to assess the sensitivity of the projections to changes in growth rates in population, labor force, and productivity. The high economic growth case assumes higher projected growth rates for population (1.0 percent per year), labor force (1.2 percent per year), and labor productivity (2.3 percent per year). With higher productivity gains, inflation and interest rates are projected to be lower than in the reference case, and economic output is projected to grow by 3.5 percent per year. GDP per capita is expected to grow by 2.5 percent per year, compared with 2.2 percent in the reference case. The low economic growth case assumes lower growth rates for population (0.6 percent per year), labor force (0.7 percent per year), and productivity (1.8 percent per year), resulting in higher projections for prices and interest rates and lower projections for industrial output growth. In the low growth case, economic output is projected to increase by 2.5 percent per year from 2001 through 2025, and growth in GDP per capita is projected to slow to 1.9 percent per year.

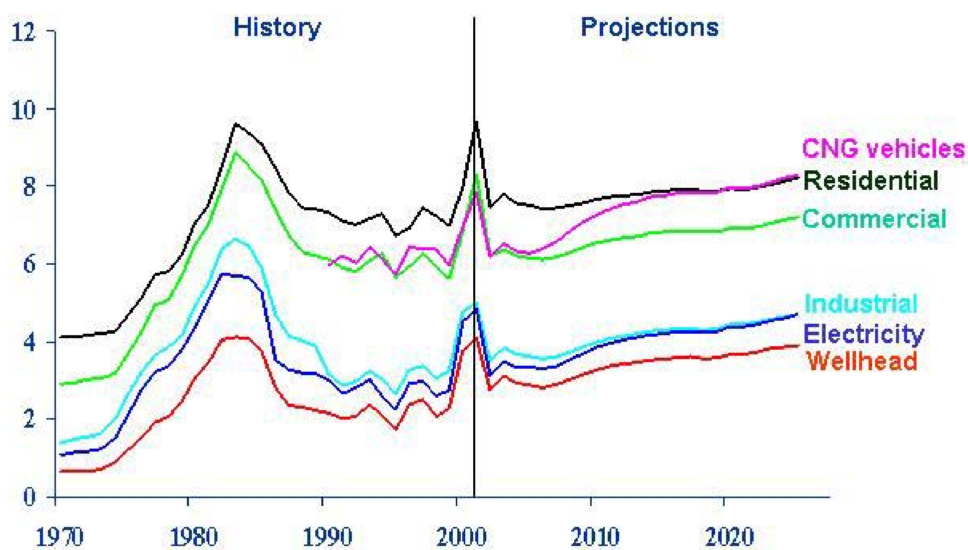
The 2025 wellhead price is projected to reach $3.83 per thousand cubic feet in the low economic growth case and $4.50 per thousand cubic feet in the high growth case. Technically recoverable natural gas resources are expected to be adequate to support the production increases projected in the three cases. As gas resources are depleted, however, wellhead prices are expected to increase, and a larger portion of U.S. natural gas consumption is projected to be met by foreign supplies and by production from Alaska.

End-use Prices. End use prices in 2003 are expected to be higher than last year due to colder weather and international events. January was about 9 percent colder than normal for the Northeast and 32 percent colder than January 2002 in that region. Ironically, the weather for the U.S. as a whole has been a bit warmer than normal in January, though there was a period of intense cold in the middle of the month. For the month of January, home heating fuel consumption was probably lighter than average, except in the Northeast. Spot prices for fuels surged, however, as crude oil and natural gas prices rose rapidly in the face of the Venezuelan oil export cutoff and sharply falling levels of domestic natural gas in storage. Some of these commodity price changes are still working their way to the consumer level. Normal temperatures through the remainder of the heating season would imply a 28-percent increase in household natural gas heating expenditures for the winter season (October-March) compared to the 2001-2002 winter. Residential natural gas prices are projected to average $9.04 per thousand cubic feet this year in current dollars and $9.27 next year, compared to $7.87 last year, $9.63 in 2001, and $7.77 in 2000.

Although residential price increases are expected to be significant, if the experience of the winter of 2000-2001 is an indication, industrial price increases could be even more significant, especially on a monthly basis. Two years ago some gas intensive industries, particularly ammonia and fertilizer producers, were particularly hard hit, with some plants shutting down production permanently. Industrial users who rely on spot market purchases for their gas and are unable to switch to an alternate fuel source face the greatest risk. Revival of the industrial sector may slow down at least until the heating season finishes and prices head downward.

End-use natural gas prices are expected to increase gradually starting in about 2005 as a result of increasing wellhead prices (Figure 10). A portion of the increase in wellhead prices is expected to be offset by a projected decline in average transmission and distribution margins as a larger proportion of the natural gas delivery infrastructure becomes fully depreciated. The average end-use price is expected to increase by 89 cents per thousand cubic feet between 2005 and 2025 (in constant 2001 dollars), compared with an increase of $1.07 per thousand cubic feet in the average price of domestic and imported natural gas supplies over the same period. Part of this difference is attributable to an increasing share of natural gas sold to electric generators, the sector with the lowest prices.

Figure 10. Natural gas end-use prices by sector, 1970-2025 (2001 dollars per thousand cubic feet)



Conclusion

Domestic natural gas prices are expected to remain high in 2003 and are at risk for significant volatility through at least the next 12 to 18 months. Strong underlying domestic demand for natural gas has been boosted by short-term or cyclical factors (including weather and oil market shifts), but expected strong levels of domestic natural gas drilling and development should provide increases in gross productive capability through 2004.

With the projected increases in both domestic gas production and imports through 2025, sufficient supplies are expected to be available to satisfy the growing demand for natural gas with wellhead price increases from $2.92 in 2002 to $3.90 in 2025 in 2001 dollars.

Thank you, Mister Chairman and members of the Committee. I will be happy to answer any questions you may have.