EIA's Natural Gas Outlook Through 2025

Guy F. Caruso
Administrator
Energy Information Administration

Independent Petroleum Association of America
June 20, 2003
Boca Raton, Florida

www.eia.doe.gov
Energy Information Administration

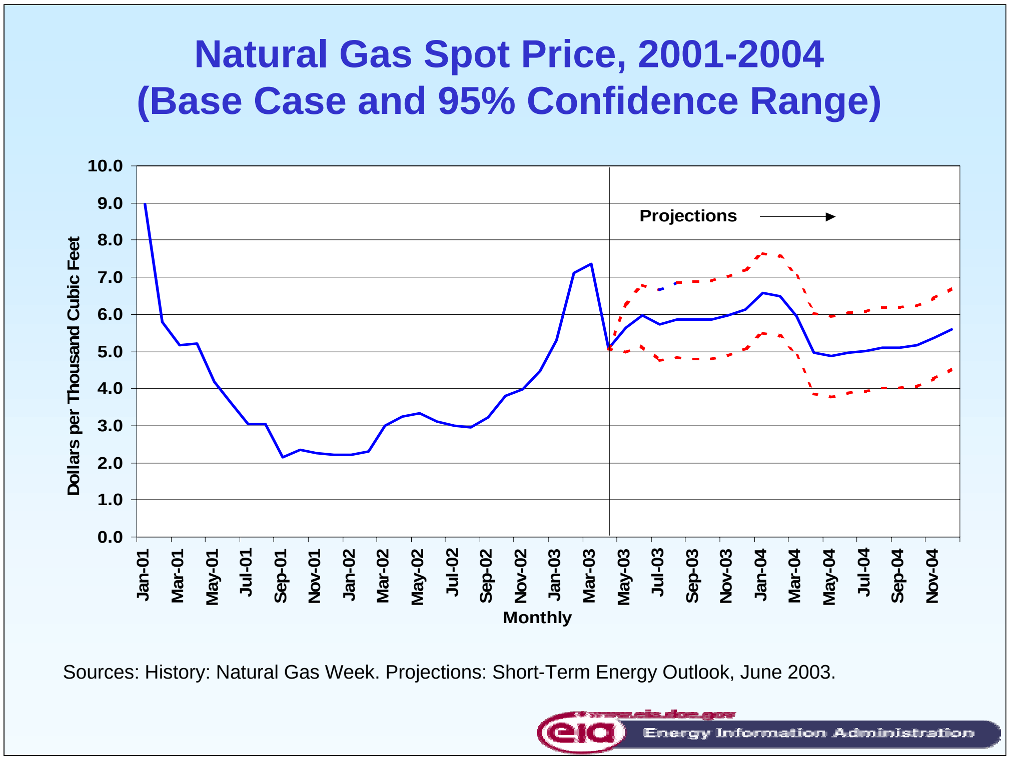
This morning I'm going to talk about EIA's short-term and mid-term natural gas outlook. How much are we going to use? Where's it going to come from? How much will it cost?

These projections are from the June *Short-Term Energy Outlook* and the *Annual Energy Outlook 2003*, which provide projections of domestic energy consumption, supply, prices, and carbon emissions. They are the product of the Energy Information Administration, an independent analytical and statistical agency within the U.S. Department of Energy. We do not speak for any particular point of view on energy policy, and our views should not be construed as representing those of the Department or the Administration.

Assumptions are critical to any forecast. The projections are not statements of what *will* happen but of what *might* happen, given certain assumptions. The reference case projections are business-as-usual forecasts, given known technology and technological trends, demographic trends, and current laws and regulations.

EIA does not propose, advocate, or speculate on changes in laws and regulations. So, one of our key assumptions is that all current laws and regulations remain as enacted. For AEO2003, that means, for example, that provisions in the current House and Senate energy bills, such as an Alaska gas pipeline tax credit, are not included in this forecast.

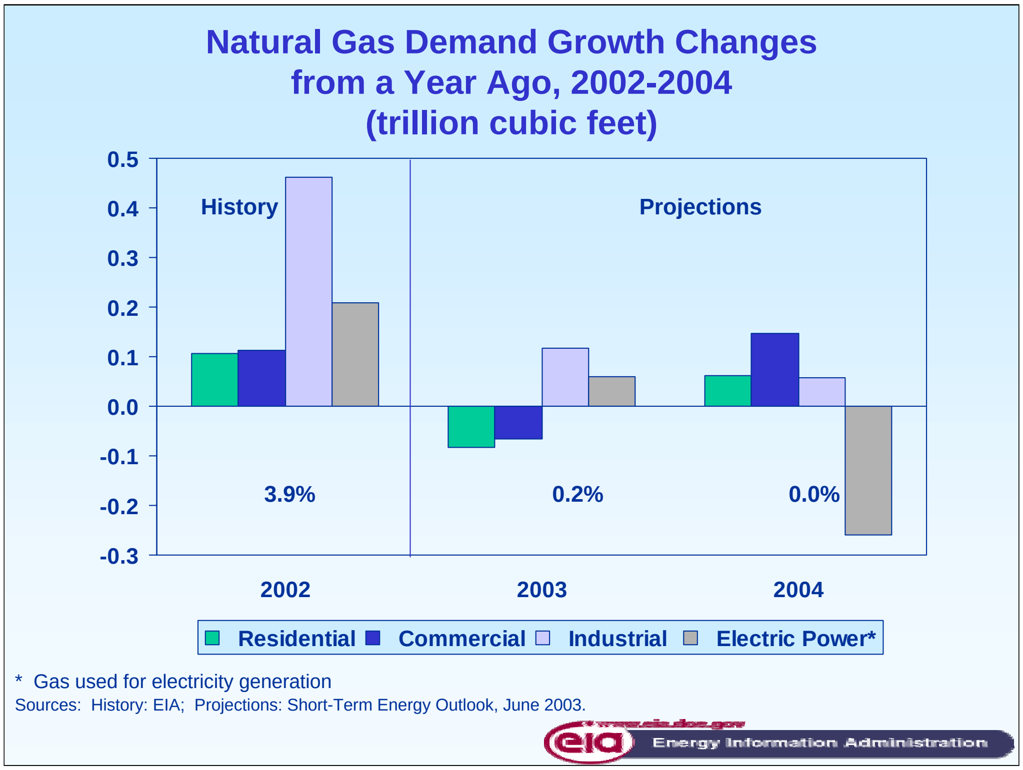
Now let's start with the short-term.



It's been a tough year for natural gas prices. On February 25 natural gas prices at the benchmark Henry Hub spot trading point peaked at $18.85 per million Btu, while New York prices peaked at $25.67. Spot prices soared as cold weather boosted space-heating demand, while low storage inventories, pipeline restrictions, and high oil prices limited buyers' supply options.

Yesterday, prices at Henry Hub stood at $5.53, with only 7 days below $5 since February. Natural gas prices are likely to stay above $5 per million Btu for the rest of the year, despite a substantial increase in drilling for natural gas and the opening of a fourth U.S. LNG terminal in July at Cove Point, Maryland. The exceptionally low level of natural gas storage continues to place unusually strong upward pressure on near-term gas prices. If this summer is hotter than normal, natural gas prices could move higher as cooling-related demand competes with the need to build storage inventories.

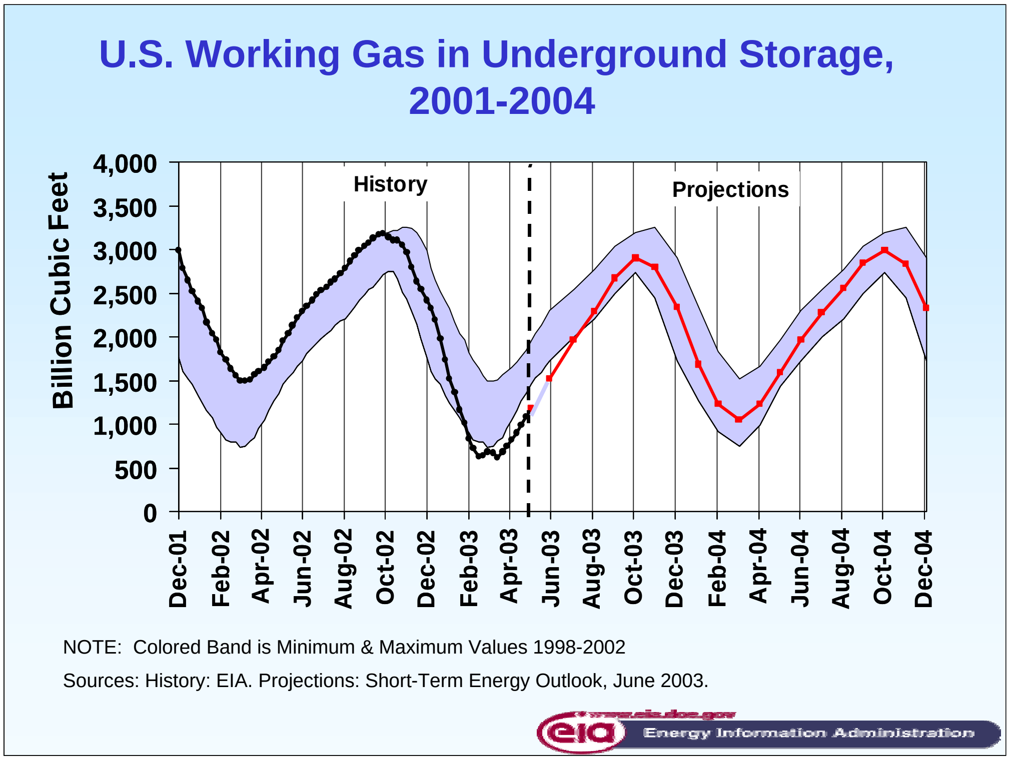
Assuming normal weather, EIA projects the average wellhead gas price at $5.34 per thousand cubic feet this year. At these levels, natural gas prices this year would be higher than the record levels seen in 2001. In 2004, increasing world oil stocks should reduce oil prices and ease natural gas prices to $4.99 per thousand cubic feet.



Total natural gas demand in 2002 increased by 3.9 percent from the 2001 level. Strong growth was particularly notable in the industrial sector as prices fell sharply from 2001 and the economy expanded at 2.4 percent annually.

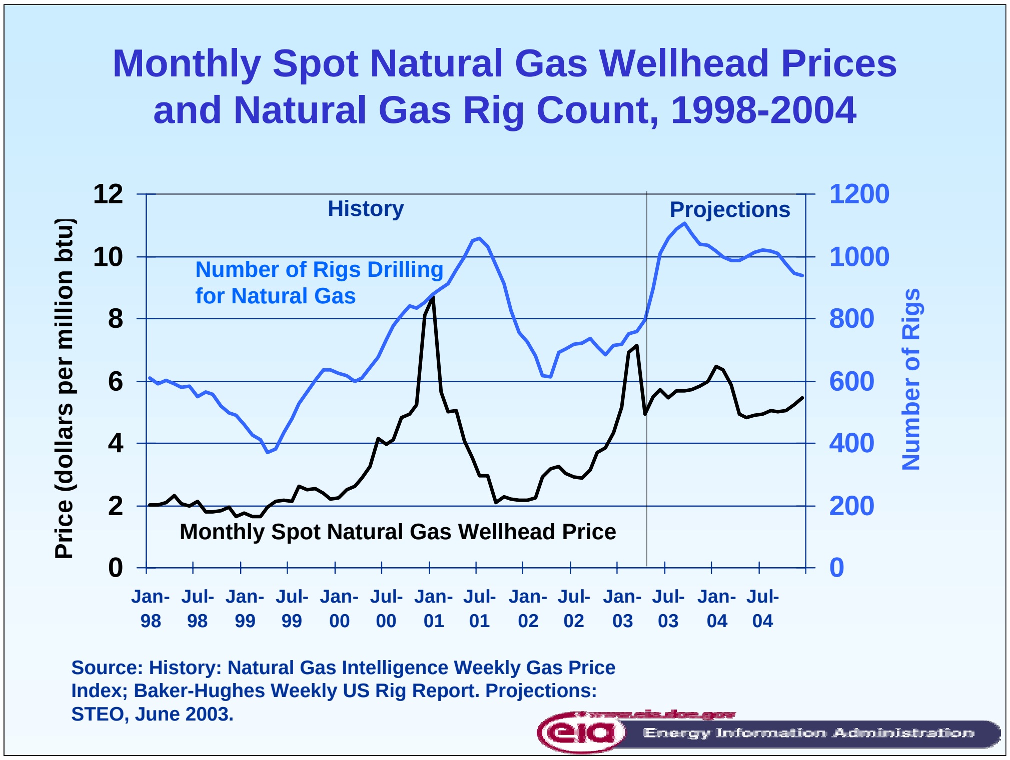
High natural gas prices are expected to reduce growth in natural gas demand by 0.2 percent in 2003. Negative growth this year is likely despite sharply higher weather-related demand during the first quarter of 2003. Demand for natural gas this summer is expected to be 0.9 percent lower than last summer's level. This is largely because cooling degree-days for the season will be close to 10 percent below year-ago levels, under our assumption of normal weather.

In 2004, natural gas demand is projected to be the same as this year, as natural gas wellhead prices average close to $5 for the year. Gas-fired electricity generation is expected to decline, as coal-fired generation increases by nearly 30 billion kilowatthours.



One of the key short-term markers is the level of working gas in underground storage. Working gas in storage was about 1,324 billion cubic feet (bcf) on June 6, about 35 percent below the year-ago level and 25 percent below the previous 5-year average. Producing region stocks were 47 percent below last year, but Eastern Region stocks were 32 percent below last year.

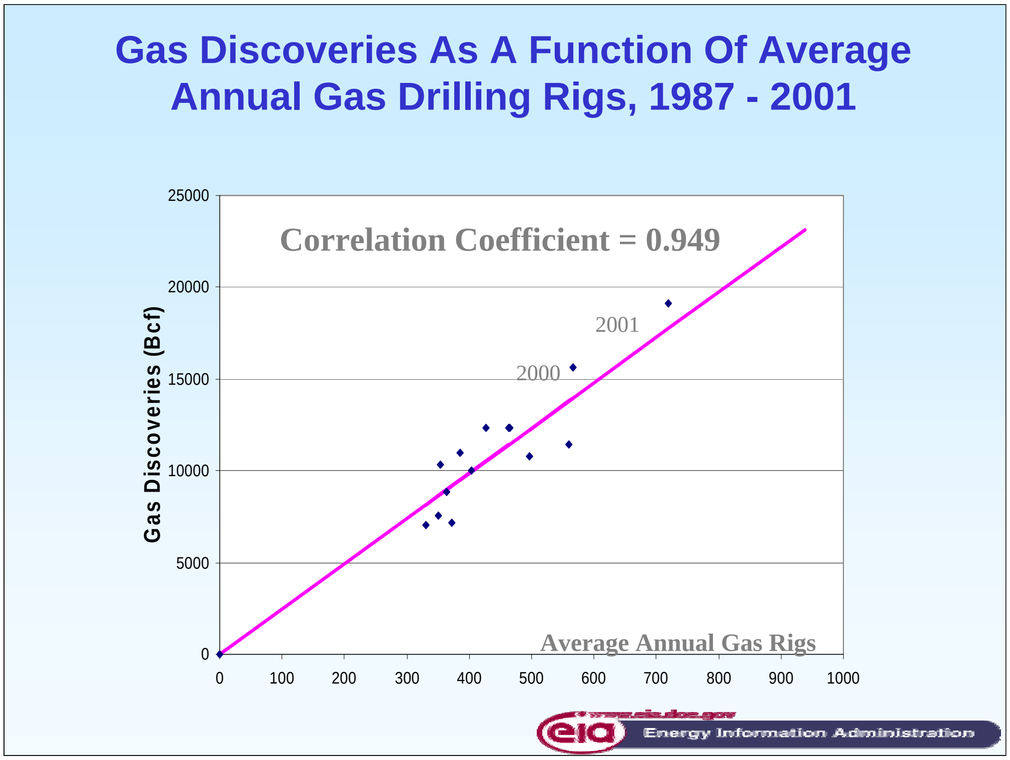
Demand for natural gas to refill working gas storage in 2003 will be larger than average, though not at the record levels we saw in 2001. As a result, storage levels are expected to remain below the previous 5-year average for the winter of 2003-2004. Relatively modest swings in supply or demand at these expected storage levels can be expected to result in significant price volatility. This is a market that frankly can't stand a large rebound in the economy, a hot summer, another cold winter, poor natural gas drilling results, or a continued tight oil market.



On the supply side higher pries have had a positive effect. As prices have increased, revenue has increased, and drilling for natural gas has increased substantially in recent months. After bottoming out at 591 rigs as of April 5, 2002, rigs drilling for natural gas have increased to 892 as of June 6, 2003. The slowdown in drilling last year resulted from low natural gas wellhead prices in 2001 and is one of the contributing factors to the high winter prices we recently experienced.

Solid increases in drilling appear likely for 2003, with the natural gas rig count exceeding 1,000 by July. Next year the number of gas wells drilled could come close to the record high levels seen in 2001.

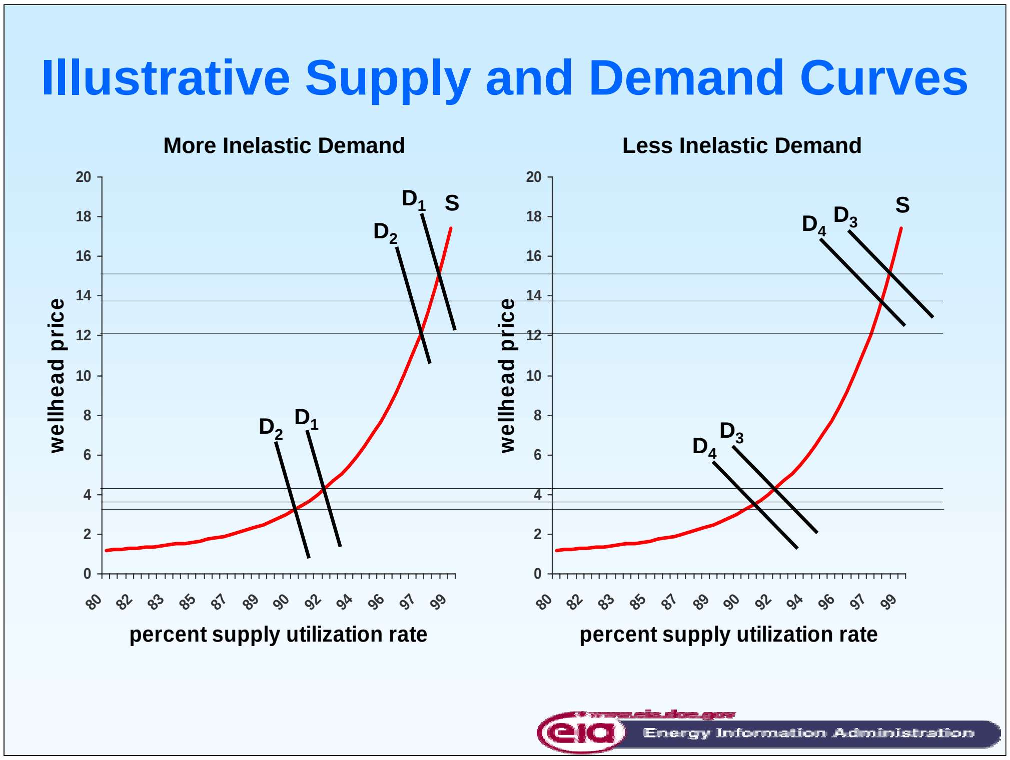
Although natural gas production fell about 1.8 percent in 2002, it is projected to increase by 2.2 percent this year. Domestic production should continue to grow in 2004, but the increase may only be 1.1 percent, as prices moderate. The prospects for significant reductions in natural gas wellhead prices over the forecast period could hinge on the productivity of the expected upsurge in drilling.



Drilling new wells is important, because the more rigs we have in the field, the more natural gas is discovered. The completion of new wells is essential to maintain and expand production, as relatively new wells provide a disproportionate share of total production, because new wells tend to have higher production rates than old wells.

Although you might have expected the productivity of gas exploration to decline in 2000 and 2001, as producers drill more shallow, quick-payoff wells, discoveries were actually above average in 2000-2001.

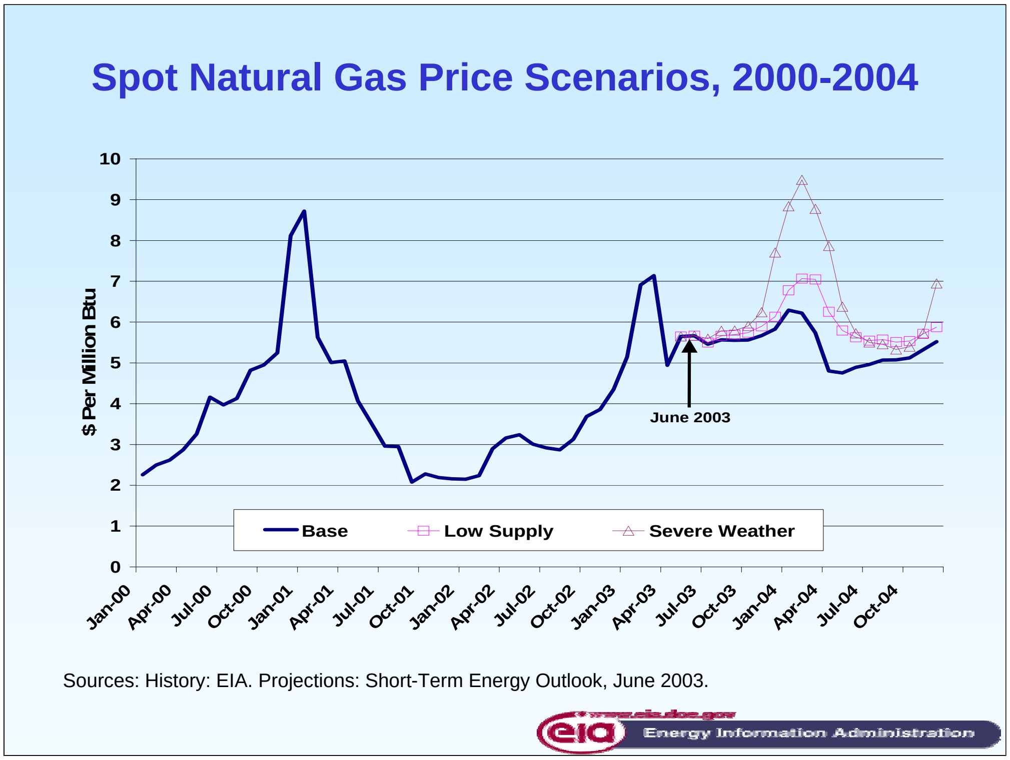
What this figure doesn't take into account is that the decline rates on new natural gas wells have been accelerating. As technology improves, wells are better targeted and produce faster. That improves cash flow, but means that more wells need to be drilled just to maintain production.



Nevertheless, we have to recognize that in the short run it's hard to do much about natural gas supply. From the time natural gas prices spike, the industry rule of thumb is that it takes 6-18 months for production to increase. And unlike oil there's no big international spot market in liquefied natural gas to moderate gas supply scarcity.

We do know that the natural gas supply curve, like any supply curve, steepens as utilization increases. The projected 2003 utilization rate is 90 percent. This is relatively high compared to 1985 and 1995, but is similar to the period 1996 to 1999. But a change in demand from hot weather or sharp economic growth could drive up prices.

In the short run, the elasticity of natural gas demand plays a significant role in price volatility. More inelastic demand means that small changes in demand lead to significantly higher prices than under less inelastic demand. Demand becomes less elastic as electric generators or industrial users lose their ability to switch to another fuel or as any user loses the ability to reduce consumption in response to higher prices.



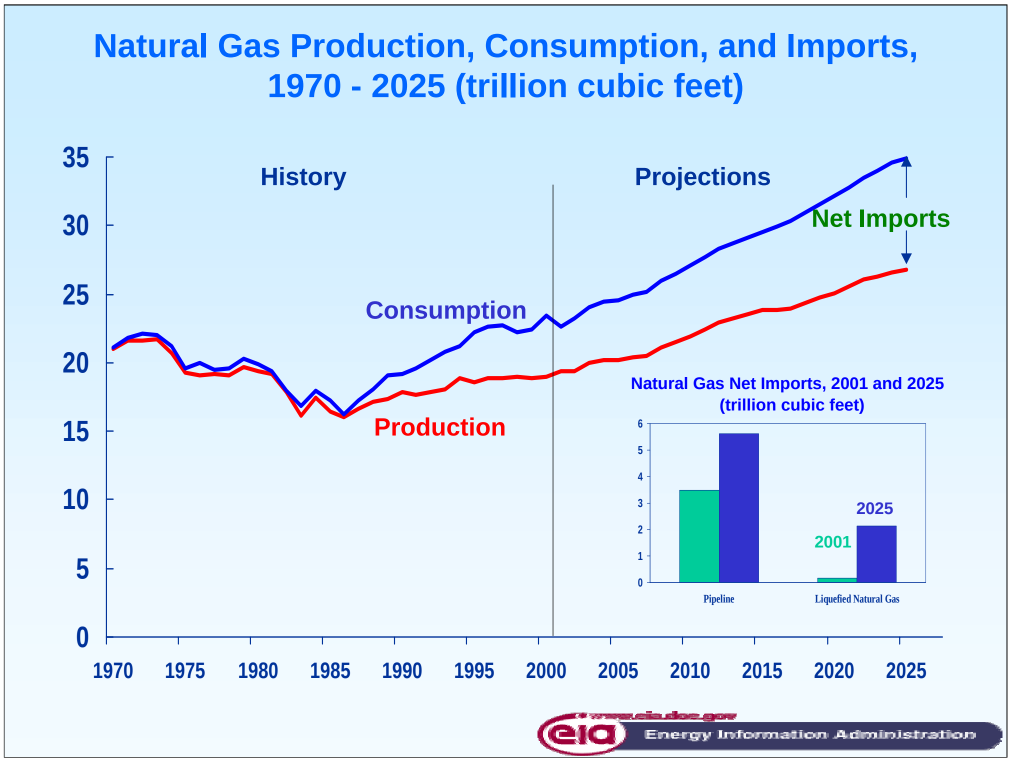
To examine the effect of supply and demand constraints, we ran the short-term model under two alternative assumptions. We found that the 10 percent hotter summer followed by a 10-percent colder winter would push natural gas deliverability to the limit and cause 50 to 60 percent higher average prices this winter. This severe weather case is extreme, but it merits attention because of our lack of a storage cushion.

On the supply side, we found that less robust assumptions about natural gas productive capacity and near-term production growth could also shift prices above the base case. We found that for every 1 percent production falls below our base case assumptions, we can expect 5 to 10 percent higher prices next winter.

Of course neither of these experiments took price spikes into account. Such spikes are characteristic of net demand surges in the context of low natural gas storage.

To summarize the EIA short-term forecast, domestic natural gas <u>prices</u> are expected to remain high in 2003 and are at risk for significant volatility through at least the next 12 to 18 months. However, in 2004 increasing world oil stocks should reduce oil prices and ease natural gas prices. In addition, strong levels of domestic natural gas drilling and development should provide increases in productive capability through 2004.

Now, let's move to the mid-term forecast through 2025.

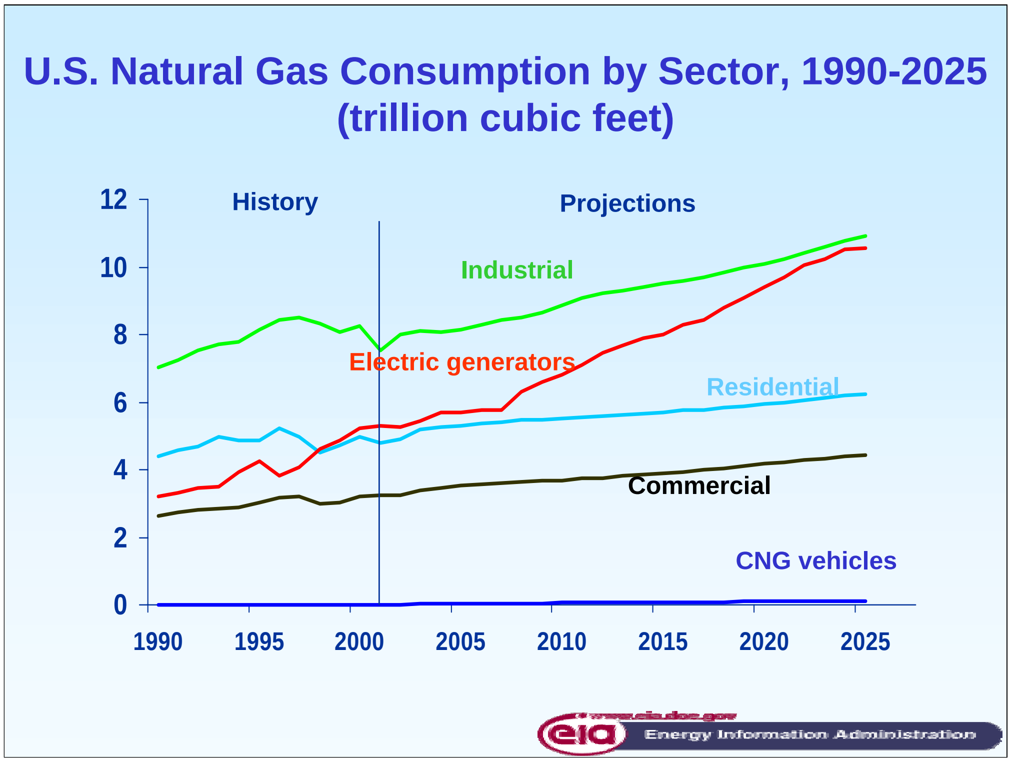


By 2025 total natural gas consumption is expected to increase to almost 35 Tcf or 26 percent of U.S. delivered energy consumption.

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.

Now, let’s look at consumption in a little more detail.



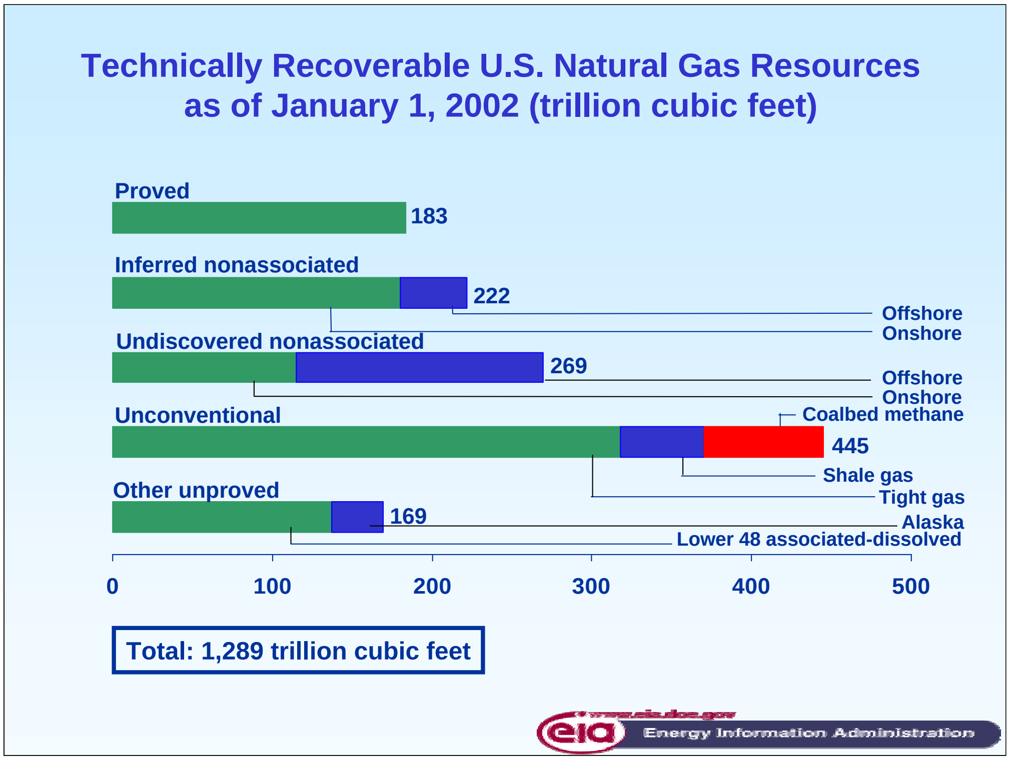
U.S. natural gas consumption is expected to increase by 1.8 <u>percent</u> annually from 2001 through 2025, to nearly 35 trillion cubic feet (Tcf). Gas consumption by electric generators is expected to double over the forecast, from 5.3 trillion cubic feet in 2001 to 10.6 trillion cubic feet in 2025. 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, natural-gas-fired generators are expected to have advantages over coal-fired generators, including lower capital costs, higher fuel efficiency, shorter construction lead times, and lower emissions.

Historically the industrial sector, <u>excluding</u> 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 by 2.6 Tcf from 2001 to 2025, driven by increasing population, healthy economic growth, and slowly 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.

Now let’s move from the demand side to the supply side.



The estimate of total technically recoverable natural gas resources as of January 1, 2002, that was used in developing our forecast is 1,289 Tcf. One way of looking at this is that we could produce almost 30 Tcf a year for the next 43 years, before we'd run out. These resource assessments come primarily from the U.S. Geological Survey for onshore regions and by the Mineral Management Service for the offshore.

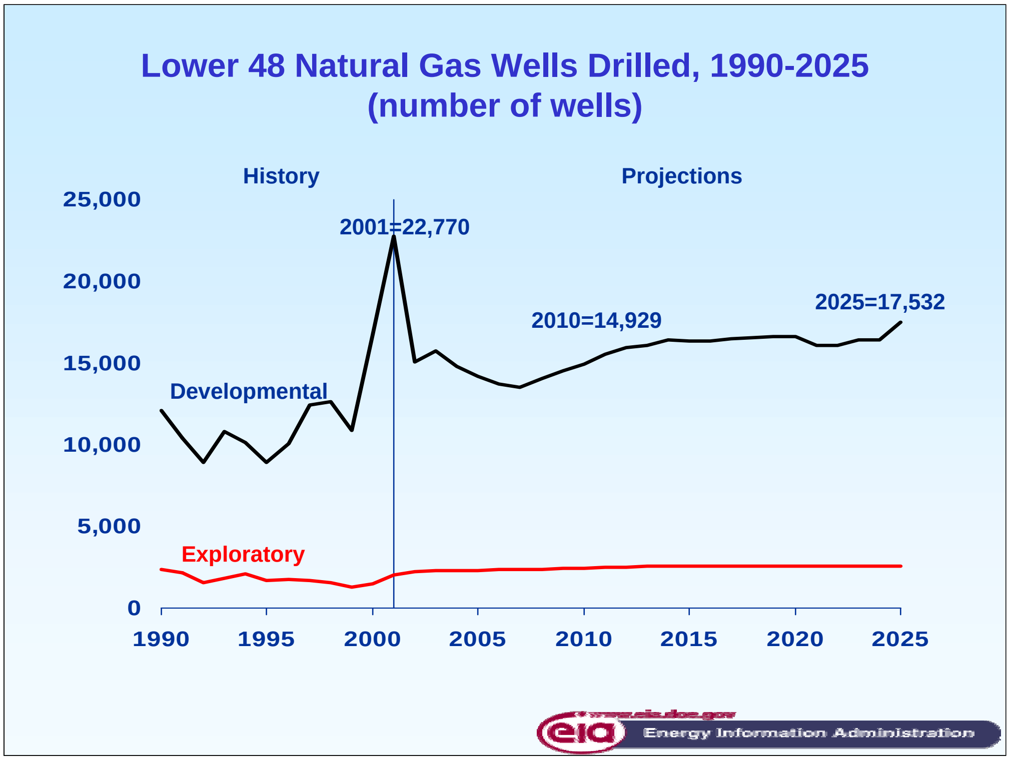
We had 183 Tcf of proved reserves in the beginning of 2002. That is, gas from known reservoirs, where wells have been drilled and production rates have been demonstrated.

Inferred reserves (at 222 Tcf) are also in known reservoirs, but data are insufficient as to the certainty of recovery. 81 percent of inferred reserves are in onshore reservoirs.

Undiscovered nonassociated conventional resources, based on regional geologic formations and their propensity to hold producible natural gas, are the least certain at 269 Tcf. More than half of these are in the offshore.

The largest category is unconventional resources with 445 Tcf, with most of that from tight sandstones at 71 percent. Other unconventional natural gas resources include gas shales and coalbed methane.

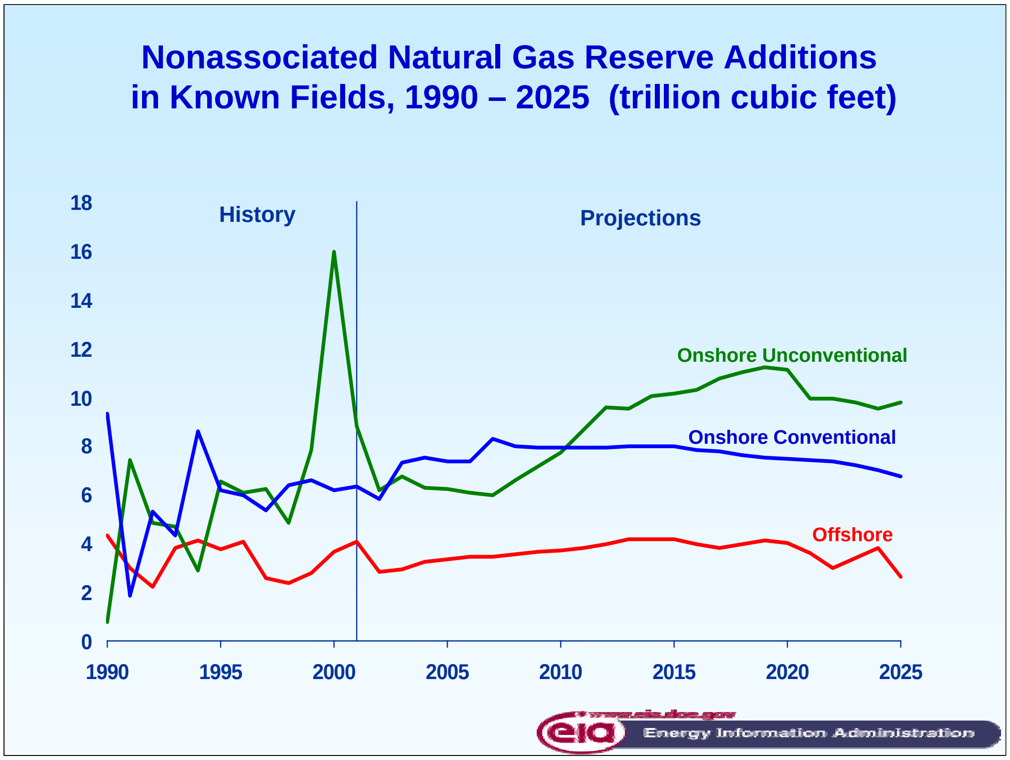
Other unproved natural gas resources include gas in Alaska (32 trillion cubic feet) and associated-dissolved natural gas in lower 48 crude oil reservoirs (137 trillion cubic feet).



One of the key activities in producing natural gas is drilling. The slowdown in drilling that resulted from low natural gas wellhead prices in 2001 was one of the contributing factors to the high prices we had this winter, and the subsequent boom in drilling we expect this summer.

Although drilling is rising now, it is expected to begin to fall off next year, and stay lower for the next few years, bringing the total number of gas wells drilled back to the historical trend. This slowdown is reversed around 2008. The number of gas wells drilled is projected to increase from 18,200 in 2000 to 20,100 in 2025. Now, 20,100 used to sound like a big number, until we hit a record 24,800 gas wells in 2001. Throughout the forecast about 98 percent of total successful gas wells are drilled in onshore areas, and more than 85 percent of the gas wells drilled are developmental. Unconventional gas drilling accounts for the vast majority of the projected growth in drilling.

Increases in drilling over the forecast are largely driven by growing revenues from drilling activities, as a result of both higher prices and higher production levels. A secondary driver of increased drilling is decreases in drilling costs resulting from technological advances. Technological improvements in the oil and gas supply industry are assumed to continue at historically estimated rates, making a larger portion of the in-place resource base technically recoverable.

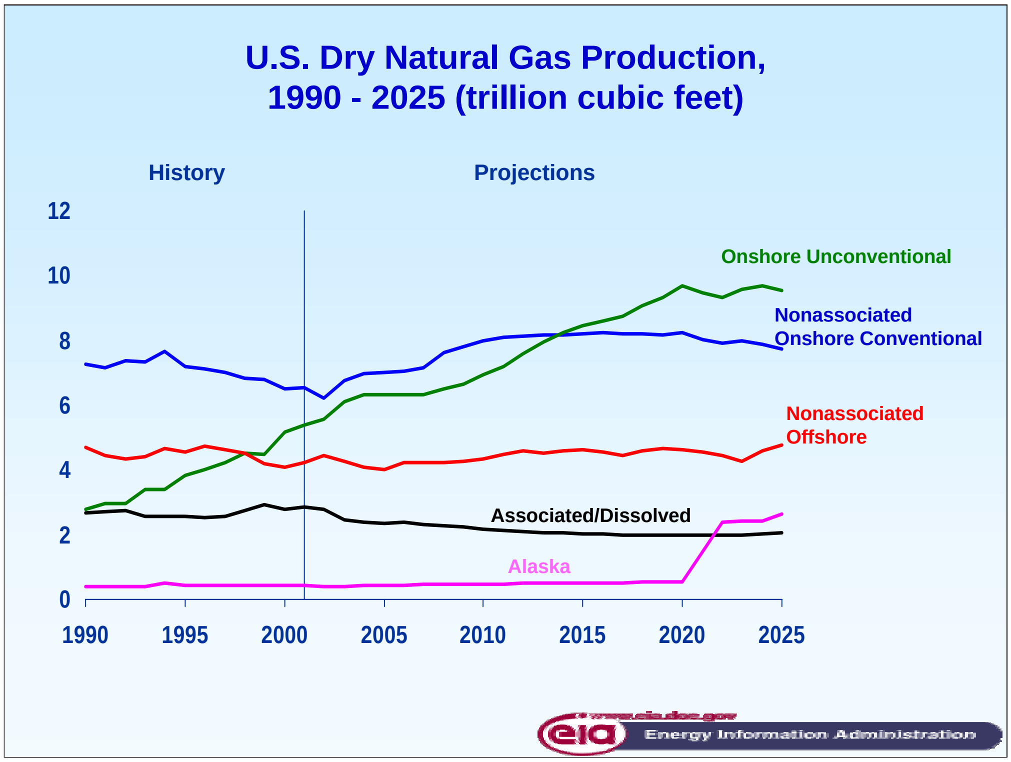


The point of drilling is to produce reserve additions.

In the 1980s and early 1990s, lower 48 natural gas production exceeded reserve additions, but the pattern reversed itself from 1994 through 1997. With the 1998 decline in prices, reserve additions once again fell below production, but they exceeded production again in 1999, 2000 and 2001. In 2002 reserve additions might have fallen below production, but through 2020 reserve addition will generally exceed production, with a few exceptions, as a result of rising prices, even with expected increases in demand.

In the forecast, annual reserve additions grow to 25.8 Tcf in 2018 and then decline. The growth in reserve additions comes primarily in the onshore, unconventional sector. Reserve additions in this sector peak in 2019, as supplies from LNG, Mexico, and Canada increase. Reserve additions from onshore conventional gas peak in 2007 at 8.3 Tcf. Reserve additions from offshore gas reach their peak in 2014 at 4.2 Tcf and then decline irregularly after that, when reserve additions from deepwater fields no longer offset the expected decline in reserves added from shallow fields.

Now let's look at the production that follows from these reserve additions.



Domestic gas production is expected to increase from 19.4 Tcf in 2001 to 26.8 Tcf in 2025. Increased U.S. natural gas production comes primarily from unconventional sources and from Alaska.

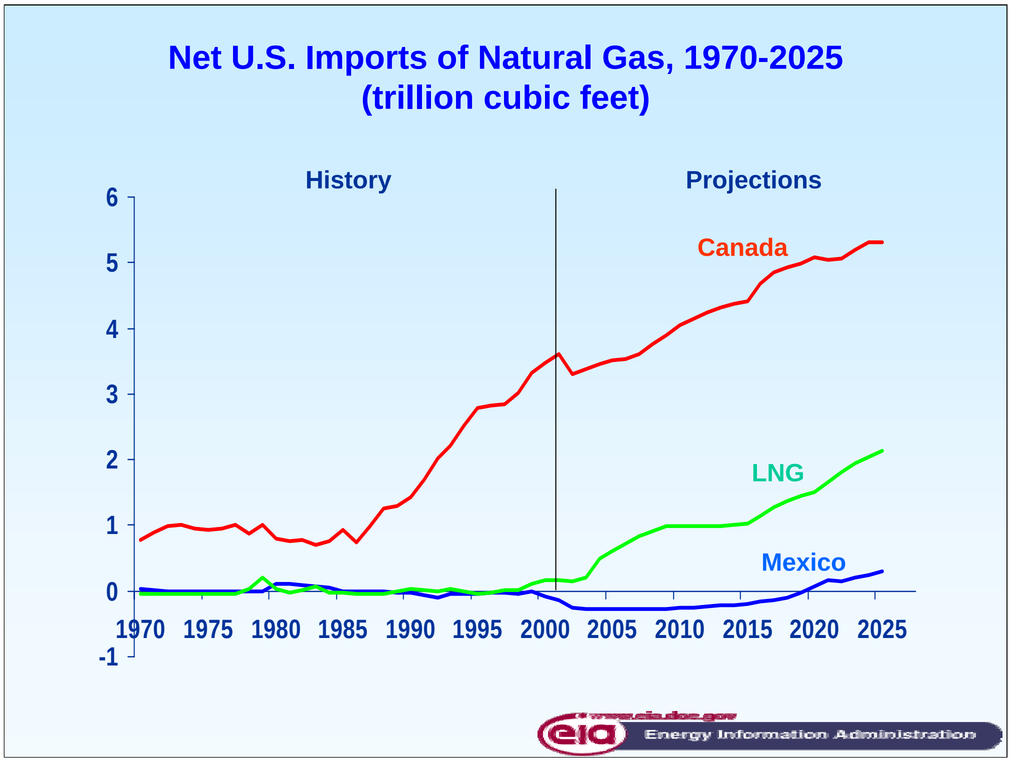
Unconventional gas production increases by 4.1 Tcf over the forecast period—more than any other source, largely because of expanded tight sands gas production in the Rocky Mountain region. Annual production from unconventional sources is expected to account for 36 percent of production in 2025, more than any other source, compared to 28 percent today.

Alaska natural gas production begins flowing to the Lower-48 States in 2021 along a pipeline through Canada, reaching 4.5 bcf per day in 2022, with further expansion beginning in 2025. 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.

Now, let’s look at the other source of supply, which is imports.



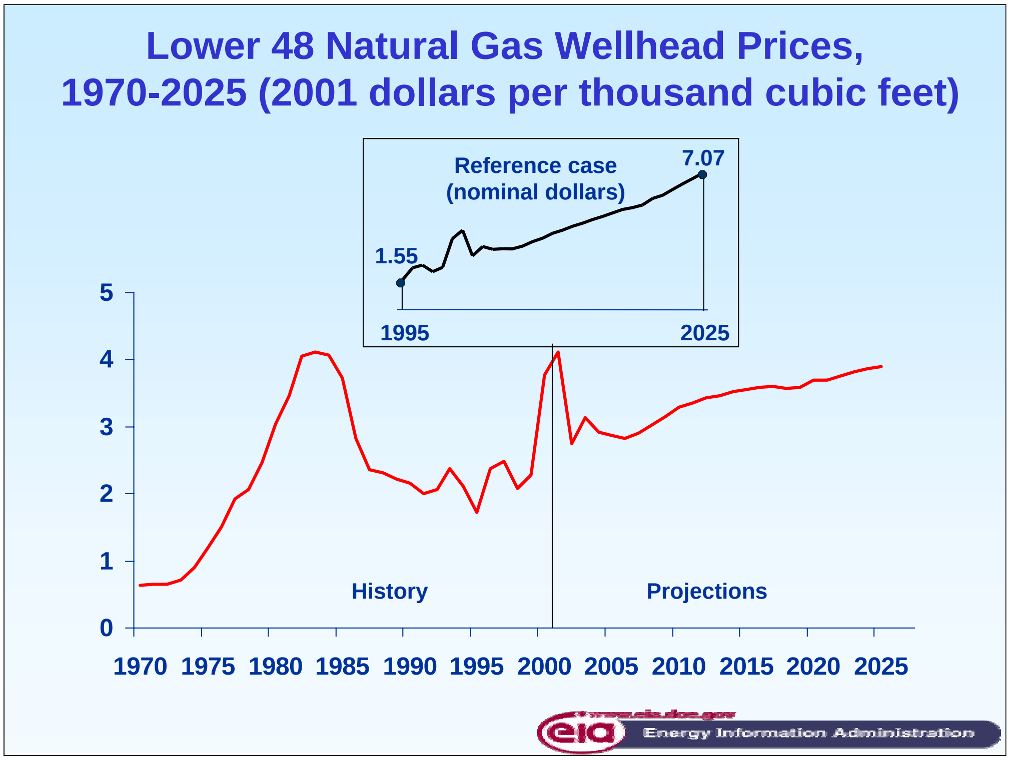
Net imports of natural gas, primarily from Canada, are projected to increase from 3.6 trillion cubic feet in 2001 to 7.8 trillion cubic feet in 2025. Imports contributed 16 percent to total natural gas supply in 2001, compared to 22 percent in 2025.

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 to 6 percent of total U.S. gas supply.

Growth in pipeline imports from Canada partly depends on the completion of the MacKenzie Delta pipeline, which 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.

Mexico is projected to go from a net importer of U.S. natural gas to a net exporter in 2020, as another 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.

All these supply and demand forecasts depend on particular price forecasts. I've told you what the end point is. Let's look at the trajectory.



Natural gas wellhead prices are projected to decline from their current high levels, falling to around $3 per thousand cubic feet <u>after</u> 2004 due to robust drilling. Over the forecast, gas prices are projected to move higher, reaching $3.90 per mcf by 2025 or 28 percent higher than the average of the last 5 years. In nominal dollars, this is equivalent to about $7 per mcf.

Natural gas wellhead 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.

Prices are projected to increase in an uneven fashion as major new, large-volume supply projects temporarily depress prices when initially brought online. These include deep and ultra-deep offshore projects in the Gulf of Mexico, liquefied natural gas facilities, the MacKenzie Delta pipeline in Canada, and an Alaskan natural gas pipeline.

www.eia.doe.gov

Energy Information Administration

In summary, 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. However, in 2004 declining oil prices should ease natural gas prices. In addition, strong natural gas drilling should increase productive capacity through 2004.

The longer-term projections indicate that more than 11 tcf of new supplies will be needed by 2025. At a wellhead price of $3.90 per mcf in 2001 dollars, LNG imports and Alaskan production are expected to provide important new sources of supply, while unconventional and Canadian gas production continue to increase.