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Mr. Chairman and Members of the Committee:

I appreciate the opportunity to appear before you today to discuss developments affecting natural gas use, particularly in the power sector. My testimony focuses on natural gas market changes that have occurred over the last 15 years and projections through 2030.

The Energy Information Administration (EIA) is an independent 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 Congress, the Administration, and the public. We do not take positions on policy issues, but we do produce data, analysis, and forecasts that are meant to assist policymakers in their energy policy deliberations. Because we have an element of statutory independence with respect to the analyses, our views are strictly those of EIA and should not be construed as representing those of the Department of Energy or the Administration.

Before turning to long-term projections, this testimony reviews historical data related to recent trends in natural gas prices and uses.

Recent History, 1990-2005

Natural Gas Prices

Natural gas markets were significantly restructured during the 1980s through enactment of statutes such as the Natural Gas Policy Act of 1978 and the Natural Gas Wellhead Decontrol Act of 1989 and by Federal Energy Regulatory Commission orders designed to increase the competitiveness of natural gas markets through unbundling and the workout of pre-existing take-or-pay contracts.

In the aftermath of these actions, the average wellhead price fell considerably from the level of $4.25 per thousand cubic feet (mcf) (Note: all prices are in 2004 dollars unless otherwise noted) reached in 1984. Between 1990 and 1999, wellhead prices averaged $2.28 per mcf and remained below $2.64 each year during this period. Natural gas consumers, particularly large electric sector and industrial users, also benefited from increasingly competitive natural gas transportation markets during this period, further reducing their delivered cost.

More recently, natural gas prices have climbed significantly. The average wellhead price in 2000 was $3.98 per mcf, 75 percent higher than the average price during the 1990s, and wellhead prices averaged $4.34 per mcf between 2000 and 2004. The average wellhead price in 2005 is estimated at $7.26 per mcf, more than three times the average price during the 1990s.

Natural Gas Use by Sector

Natural gas consumption in the United States fell from 22.1 trillion cubic feet (tcf) in 1972 to 16.2 tcf in 1986. Between 1986 and 1997, consumption rose to 22.7 tcf. Since 1997, overall consumption has been relatively stable near this level.

Residential and commercial consumption of natural gas has also been relatively flat over the past decade (**Figure 1**). Over 60 million households in the United States are currently heated with natural gas, and natural gas continues to be the fuel of choice for about two-thirds of new single-family houses. Consumption in the residential and commercial sectors is driven largely by the seasonal demand for space heating.

Annual consumption of natural gas for electricity generation has increased from a range of 3.2 to 3.9 tcf during the early 1990s to an estimated range of 5.1 to 5.8 tcf from 2000 to 2005. Although the overall trend shows increasing use in this sector, consumption varies from year to year, driven largely by weather, electricity demand, and any disruption in alternative generation facilities.

Rising use of natural gas by electric generators over the past decade has been roughly offset by a decline of natural gas use in the industrial sector, which uses more natural gas than any other sector. Industrial consumption reached 9.7 tcf in 1997, a level second only to peak levels in the 1970s, and decreased to an estimated 7.8 tcf in 2005 as natural-gas-intensive manufacturing activities responded to recent natural gas price developments.

Natural Gas in Electricity Generation

An increase in natural gas generation does not necessarily imply a commensurate increase in natural gas consumption by electric generators if the efficiency of generation is also changing. The gap between the 118-percent increase in natural gas-fired generation (from 309 billion kilowatthours to an expected value of 673 billion kilowatthours) between 1990 and 2005 and the smaller 84 percent increase in natural gas used by electric generators over the same period implies that the average efficiency of all natural gas generation improved by roughly 16 percent.

The increase in the apparent efficiency of natural gas generation over the past 15 years largely reflects the recent introduction of increasingly efficient and reliable natural gas generating technologies, notably advanced combined-cycle units. Between 1999 and 2005, over 230 gigawatts of new generating capacity was added and nearly all of it was primarily natural-gas-fired (**Figure 2**). This rate of generating capacity expansion has not been seen since the 1970s. The availability of this technology, which allowed capacity to be added in modest increments close to major load centers with a relatively short construction time, along with attractive natural gas prices during the 1990s, the 1987 repeal of provisions in the Power Plant and Industrial Fuel Use Act that had previously prohibited the use of natural gas by new electric generating units, and Clean Air Act provisions favoring the use of inherently cleaner fuels all played some role in driving this outcome.

It is also worth noting that rapid growth in natural gas capacity does not necessarily imply a commensurate increase in natural gas generation if the new plants are not used very intensively. Under present natural gas market conditions, many of the new natural gas plants are not operating very intensively, and older, less efficient oil and natural gas plants are being retired. If all the natural gas plants added between 1990 and 2005 were running at just a 50 percent utilization rate (which would be substantially more than the actual experience) while the older

natural gas plants continued to operate, the increase in natural gas generation would have been about 1,150 billion kilowatthours, more than three times the actual increase.

Over the same 1990 to 2005 period, amendments to the Clean Air Act have required the power industry to significantly reduce emissions. The Clean Air Act Amendments of 1990 (CAAA90) called for reductions in the annual emissions of sulfur dioxide (SO_2) by electricity generators in the power sector. SO_2 emissions had to be reduced to approximately 12 million tons in 1996, 9.48 million tons per year from 2000 to 2009, and 8.95 million tons per year thereafter. The CAAA90 also called for significant reductions in nitrogen oxide emissions (NO_x), setting boiler-type specific NO_x emissions standards for each plant.

Between 1990 and 2005 both SO_2 and NO_x emissions in the power sector fell significantly, with SO_2 emissions declining over 30 percent while NO_x emissions declined over 40 percent (**Figure 3**). These reductions were mostly achieved by adding emissions control equipment or switching to lower sulfur subbituminous coal at many of the Nation's coal plants. However, reducing these emissions has not led to a reduction in coal generation. In fact, despite few new plants being added between 1990 and 2005, coal generation in the power sector increased from 1,572 billion kilowatthours to 2,001 billion kilowatthours, a 27–percent increase. While natural gas generation grew more in percentage terms, coal generation actually increased by a larger amount in absolute terms, 429 billion kilowatthours versus 364 billion kilowatthours over this period.

Cumulative retirements of coal-fired units between 1990 and 2004 were less than 2 percent of coal-fired capacity and were concentrated among smaller units. Generally speaking, it is less cost-effective to retrofit emissions controls on smaller coal-fired generating units than on larger ones. In this regard, smaller coal-fired generators faced choices similar to those facing industrial boilers that used coal or residual fuel oil, which often responded to emissions control requirements by switching to natural gas or curtailing their operations.

A major reason that so few coal plants were added during the 1990s is that most generating companies did not need large new baseload power plants that are designed to operate at high utilization rates regardless of seasonal and diurnal variations in total electricity demand. In 1990, the average capacity factor for power sector coal plants was only 59 percent, while the average for nuclear plants, another baseload technology, was only 66 percent. These relatively low rates of utilization left substantial room for increases in coal and nuclear generation without the need to add new capacity. With the growth in electricity demand that has occurred over the last 15 years, existing coal and nuclear plants are now being used more intensively, and power companies are starting to plan for new baseload capacity.

Projections, 2005-2030

Near-Term Projections

Over the next few years, natural gas prices and consumption are likely to vary with weather and economic conditions. Currently natural gas prices remain high relative to historical prices, but they have declined in recent weeks because of a warmer-than-normal winter in most parts of the

country to date. EIA's February 2006 *Short-Term Energy Outlook* (*STEO*) projects that the wellhead price will average roughly $7.90 per mcf in both 2006 and 2007 (nominal dollars). These prices reflect both limited supplies as well as the projected prices for competing fuels. Overall, domestic dry natural gas production in 2005 is estimated to have declined by 2.7 percent, mostly because of hurricane-related disruptions in production in the Gulf of Mexico. As the recovery from the hurricanes continues, dry gas production is projected to increase by 3.0 percent in 2006 and by 1.3 percent in 2007. On January 27, working gas in storage stood at an estimated 2,406 billion cubic feet (bcf), which is the highest stock level for this time of year since 1989. Natural gas stocks are 296 bcf above 1 year ago and 529 bcf above the 5-year average.

Summer weather in 2006 is expected to be cooler than the summer of 2005, which was one of the hottest on record. As a result, demand for natural gas for production of electricity is expected to fall in 2006 and then increase in 2007.

Long-Term Projections

The long-term projections discussed here are drawn from the reference case of the *Annual Energy Outlook 2006* (*AEO2006*), which was released in December 2005. The *AEO2006* is based on Federal and State laws and regulations in effect on October 1, 2005, including those sections of the Energy Policy Act of 2005 that establish specific tax credits, incentives, or standards. However, the potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in the projections. The *AEO2006* also includes the provisions of the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR), issued by the U.S. Environmental Protection Agency (EPA) in March 2005. These rules are expected to result in large reductions of emissions from power plants.

The *AEO2006* is not meant to be an exact prediction of the future but represents what might happen, 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 and subject to many random events that cannot be foreseen, such as political disruptions and technological breakthroughs. In addition to these phenomena, long-term trends in technology development, demographics, economic growth, and energy resources may evolve along a different path than expected in the projections. The *AEO2006* includes many alternative cases intended to examine the implications of such uncertainties.

Natural Gas Prices

In the *AEO2006* reference case, average wellhead prices for natural gas in the United States decline from $5.49 per mcf (2004 dollars) in 2004 to $4.46 per mcf in 2016 as the availability of new import sources and increased drilling expand available supply (**Figure 4**). After 2016, wellhead prices are projected to increase gradually, reaching $5.92 per mcf in 2030. Growth in liquefied natural gas (LNG) imports, Alaskan production, and lower-48 production from

unconventional sources is not expected to be large enough to completely offset the impacts of resource depletion and increased demand in the lower-48 States (**Figure 5**).

Natural Gas Supply

Domestic dry natural gas production is projected to increase from 18.5 tcf in 2004 to 21.6 tcf in 2019, before declining to 20.8 tcf in 2030 in the *AEO2006* reference case. Net pipeline imports of natural gas, are expected to decline from 2004 levels of 2.8 tcf to about 1.2 tcf by 2030 due to resource depletion and growing domestic demand in Canada.

To meet a projected demand increase of 4.5 tcf from 2004 to 2030 and to offset an estimated 1.6-tcf reduction in net pipeline imports, the United States is expected to depend increasingly on imports of LNG. Net LNG imports in the *AEO2006* reference case are projected to increase from 0.6 tcf in 2004 to 4.4 tcf in 2030. Besides expansion of three of the four existing onshore U.S. LNG terminals (Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana) and the completion of two U.S. terminals currently under construction, new facilities serving the Gulf Coast, Southern California, and New England are added in the reference case.

Natural Gas Consumption

The total demand for natural gas is projected to increase at an average annual rate of 1.2 percent from 2004 to 2020, then to remain relatively stable through 2030. The demand for natural gas in the residential, commercial, and industrial sectors is projected to increase steadily, but at a rate well under 1 percent per year from 2004 to 2030. The projected leveling off in total natural gas consumption after 2020 is driven by changes in the mix of fuels used to generate electricity, as natural gas is expected to lose market share to coal in the electric power sector during the latter half of the projection period. Natural gas consumption in the electric power sector is projected to grow at the relatively rapid rate of 1.2 percent per year between 2004 and 2019, before it begins to decline. Between 2019 and 2030, natural gas consumption in the power sector is expected to decline by 15 percent. Over the entire 2004 to 2030 period, natural gas consumption in the power sector increases from 5.3 tcf to 6.4 tcf.

Electric Power Sector Generation and Capacity Additions

The demand for electricity is expected to grow at an average rate of 1.6 percent per year through 2030. To meet this growth, the power sector will increase its use of coal, natural gas, renewable fuels, and nuclear power (**Figure 6**). In the mid-term, over the next 10 years, both natural gas and coal generation increase as existing plants are used more intensively. Renewable generation also grows as new plants stimulated by the tax credit extension in EPACT2005 are added. For example, between 2004 and 2015, coal generation in the power sector is projected to increase from 1,954 billion kilowatthours to 2,239 billion kilowatthours, while natural gas generation grows from approximately 619 billion kilowatthours to 902 billion kilowatthours, and renewable generation grows from 323 billion kilowatthours to 448 billion kilowatthours.

After 2010, capacity additions are expected to be increasingly dominated by new coal power plants and coal generation grows significantly (**Figure 2**). For example, through 2005 natural gas plants accounted for over 90 percent of the capacity added in the expansion that began in

1999. However from 2010 on new coal plants are expected to account for 57 percent of total capacity additions, while natural gas technologies account for 36 percent, renewable plants account for 5 percent, and nuclear plants accounts for the remainder. Even with higher fuel prices, natural gas plants, because of their lower construction costs, are generally the most economical choice for plants that are needed to operate less intensively. Over the entire 2005 to 2030 time period, 174 gigawatts of new coal capacity, including 19 gigawatts of coal-to-liquids plants in the industrial sector, are added to make liquid fuels and electricity.

Clean Air Interstate Rule and Clean Air Mercury Rule

Our projections show that increases in coal-fired generation are expected to occur despite significant reductions in sulfur dioxide (SO_2), nitrogen oxide (NO_x), and mercury emissions that are required because of recently promulgated regulations. The EPA issued the CAIR in March 2005. CAIR caps emissions of SO_2 for the District of Columbia and 28 states in the East and Midwest. CAIR is scheduled to supersede Title IV of the Clean Air Act through the use of a cap-and-trade approach. Phase I of CAIR comes into effect in 2010 for SO_2 and Phase II enters into effect in 2015. CAIR will also regulate NO_x emissions. Each affected state will be subject to two NO_x limits under CAIR: a 5-month summer season limit and an annual limit. These caps are expected to stimulate additions of emission control equipment to some existing plants.

In March 2005, EPA also issued the CAMR, which establishes a cap-and-trade approach to reduce mercury emissions from coal-fired power plants in the United States. In addition to nationwide caps, each new and existing coal-fired power plant must meet mercury emissions standards based on its coal type. Mercury has to be reduced in two phases: the national Phase I mercury cap is 38 short tons in 2010 and the Phase II cap is 15 short tons by 2018, though emissions banking is allowed. Several States have also adopted or are considering mercury control regulations for power plants within their jurisdictions.

In order to meet CAIR and other State requirements, power companies are projected to add flue gas desulfurization equipment to 141 gigawatts of capacity. Because of these actions and the growing use of lower-sulfur coal, SO_2 emissions are projected to drop from 10.9 million short tons in 2004 to 3.7 million short tons in 2030, a 66-percent decline (**Figure 3**). National NO_x emissions are projected to decrease from 3.7 million short tons in 2004 to 2.2 million short tons in 2030, a decline of 41 percent. The primary compliance option for reducing NO_x will be the addition of selective catalytic reduction equipment to 118 gigawatts of generating capacity. To comply with CAMR, power companies are expected to reduce their mercury emissions from over 50 tons in 2004 to 15 tons by 2030, a decline of more than 70 percent. Power companies are expected to retrofit about 125 gigawatts of capacity with activated carbon injection technology in order to comply with CAMR.

Although EIA does not anticipate that the emissions limits in CAIR and CAMR will lead to significant fuel switching away from coal, other types of emissions regulations could have such an effect. For example, several recent EIA analyses have found that stringent greenhouse gas limits could result in a major shift from coal to other fuels for electricity generation.

Conclusions

There are major uncertainties with any projection that looks out even a few years. For longer-term projections like those in the *AEO2006*, key uncertainties include the rate of technological change, the rate of economic growth, unforeseen policy changes, and changes in consumer preferences. The *AEO2006* includes numerous cases to examine many of these uncertainties. These include alternative economic growth cases, alternative fuel price cases, and many alternative technology cases. Generally, the only cases showing much greater use of natural gas in the power sector were those with much lower natural gas prices than are projected in the reference case.

This completes my testimony, Mr. Chairman. I would be glad to answer any questions you and the other members may have.

Figure 1. Natural Gas Consumption by Sector
(trillion cubic feet)

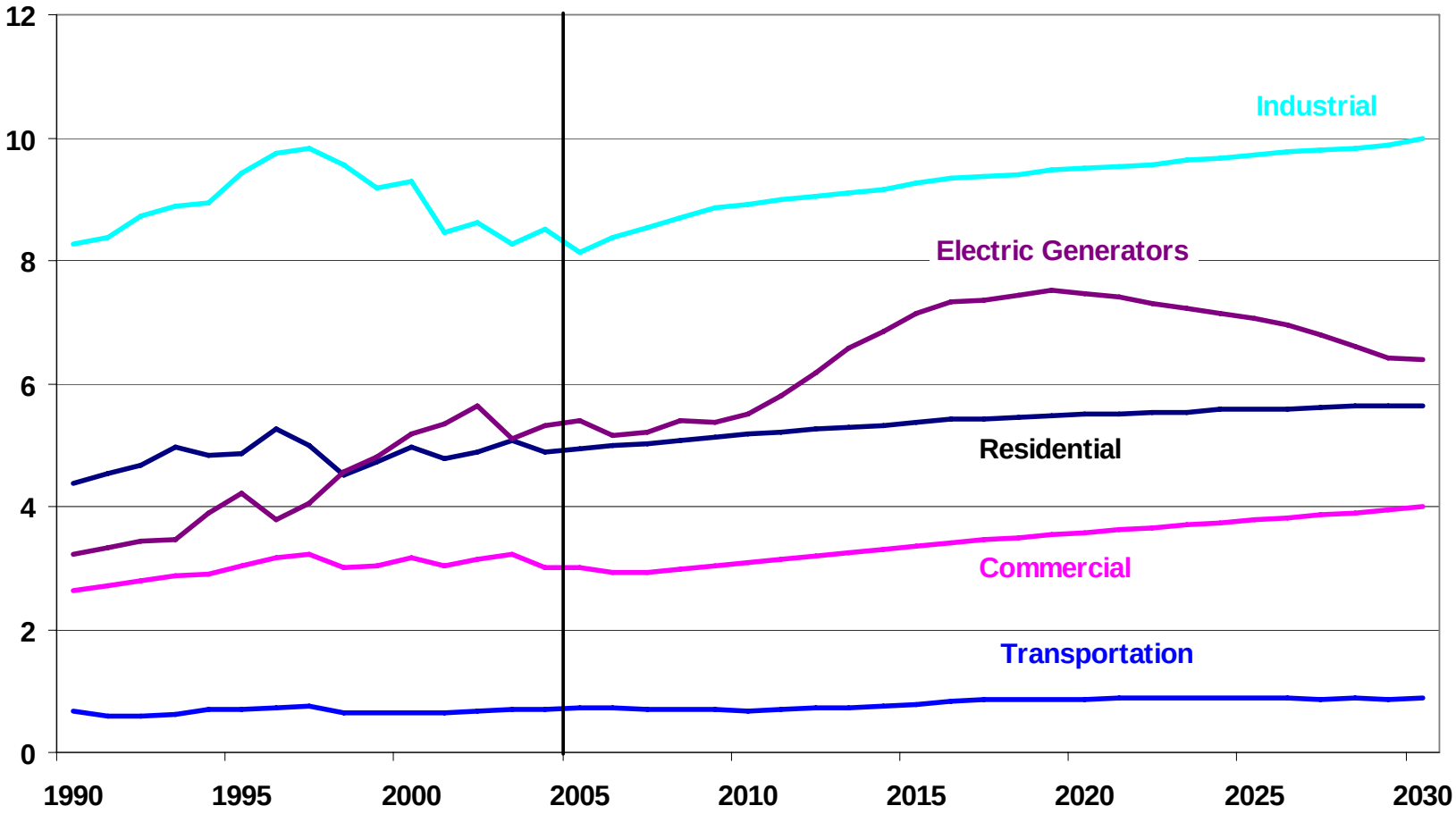


Figure 2. Capacity Additions by Year and Fuel (gigawatts)

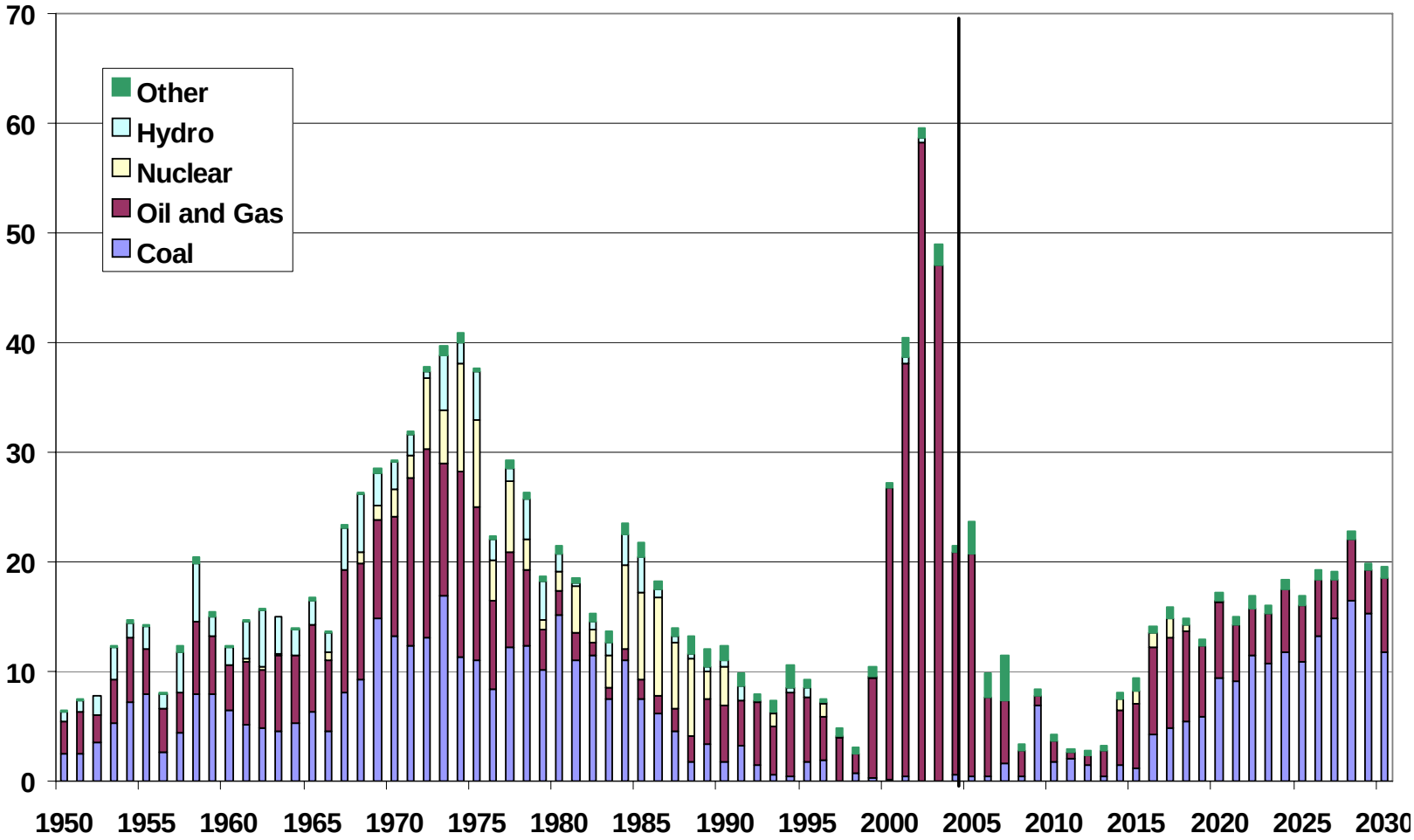


Figure 3. Power Sector Emissions
(million tons)

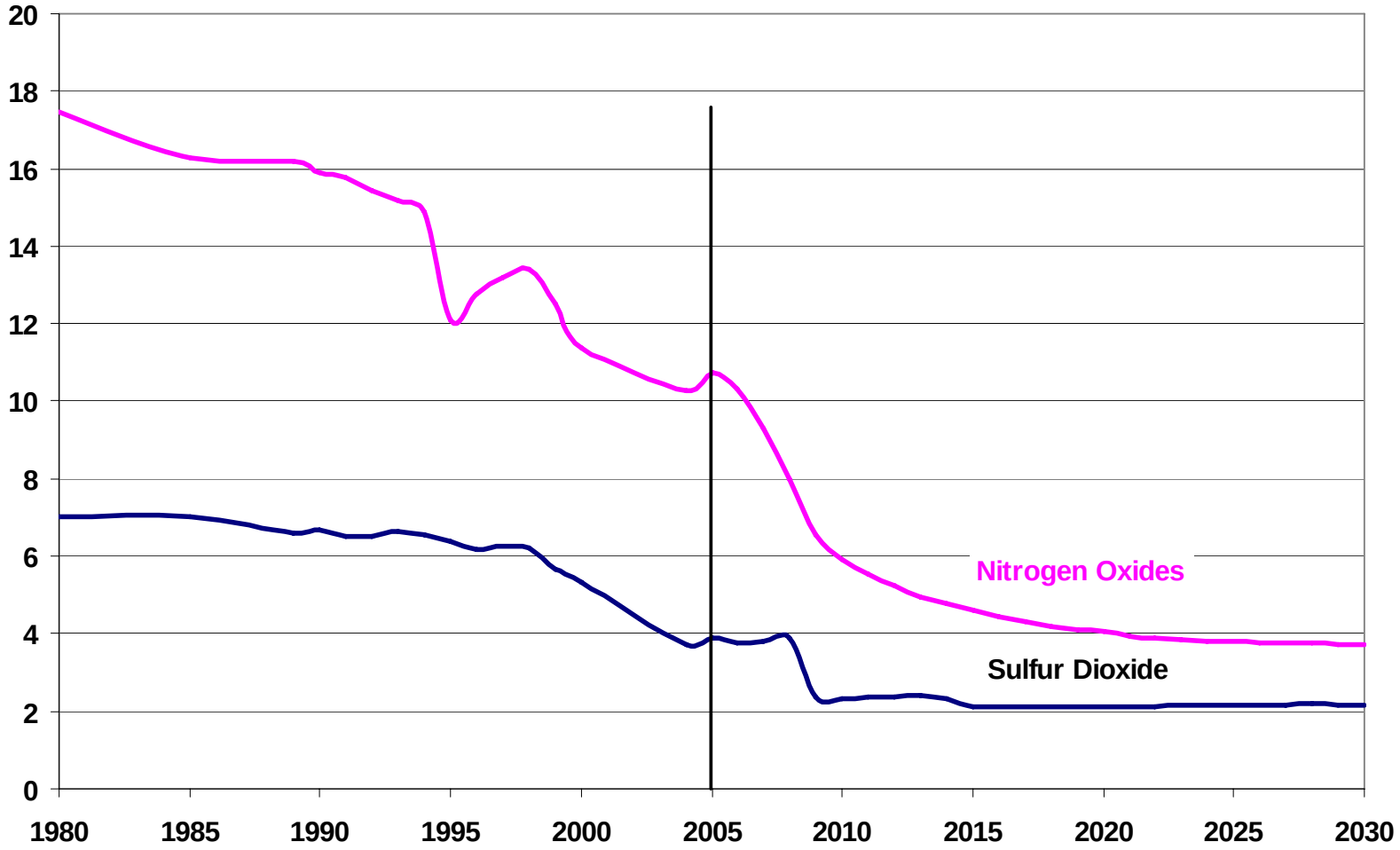


Figure 4. Natural Gas Wellhead Prices

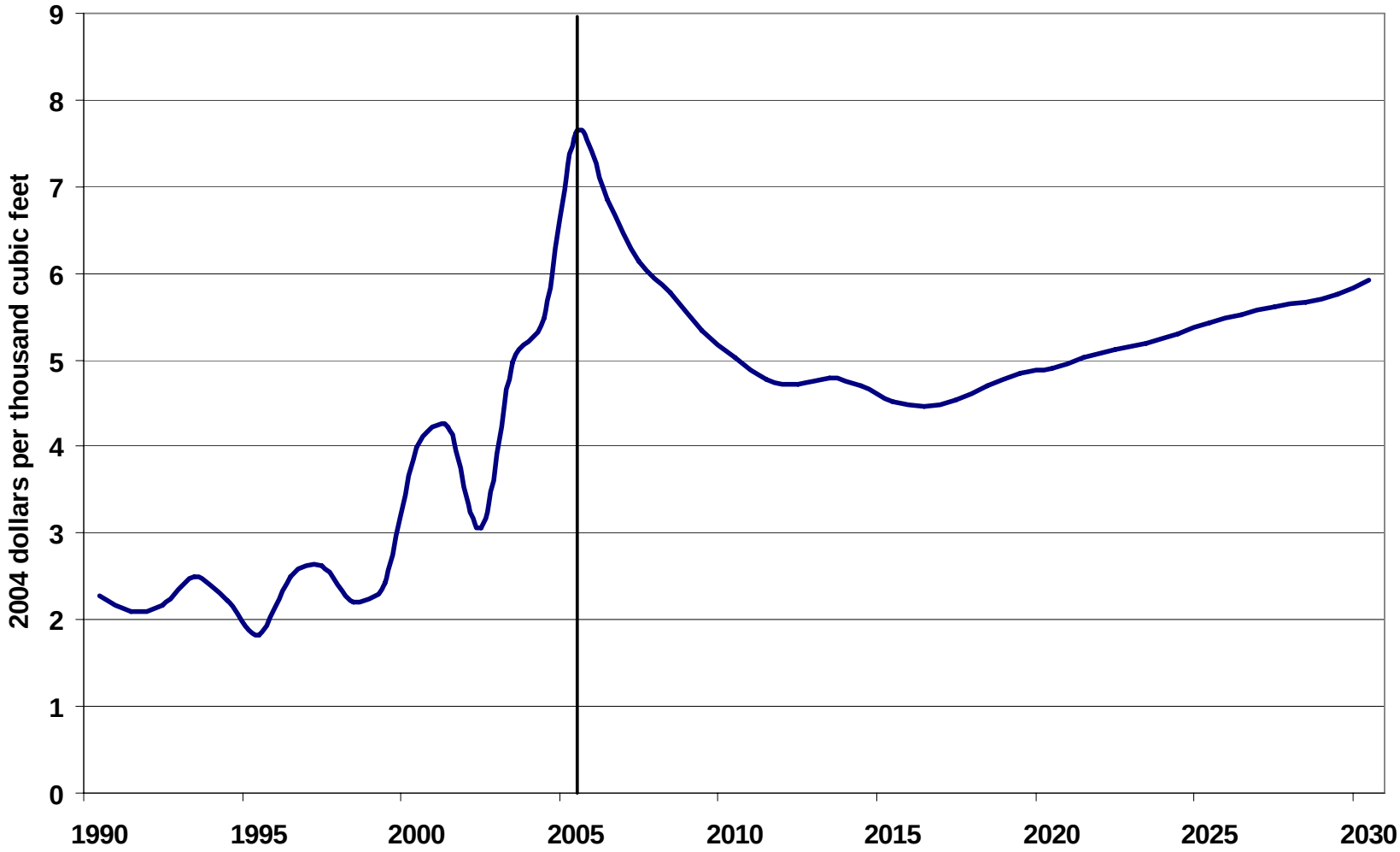


Figure 5. Natural Gas Supply
(trillion cubic feet)

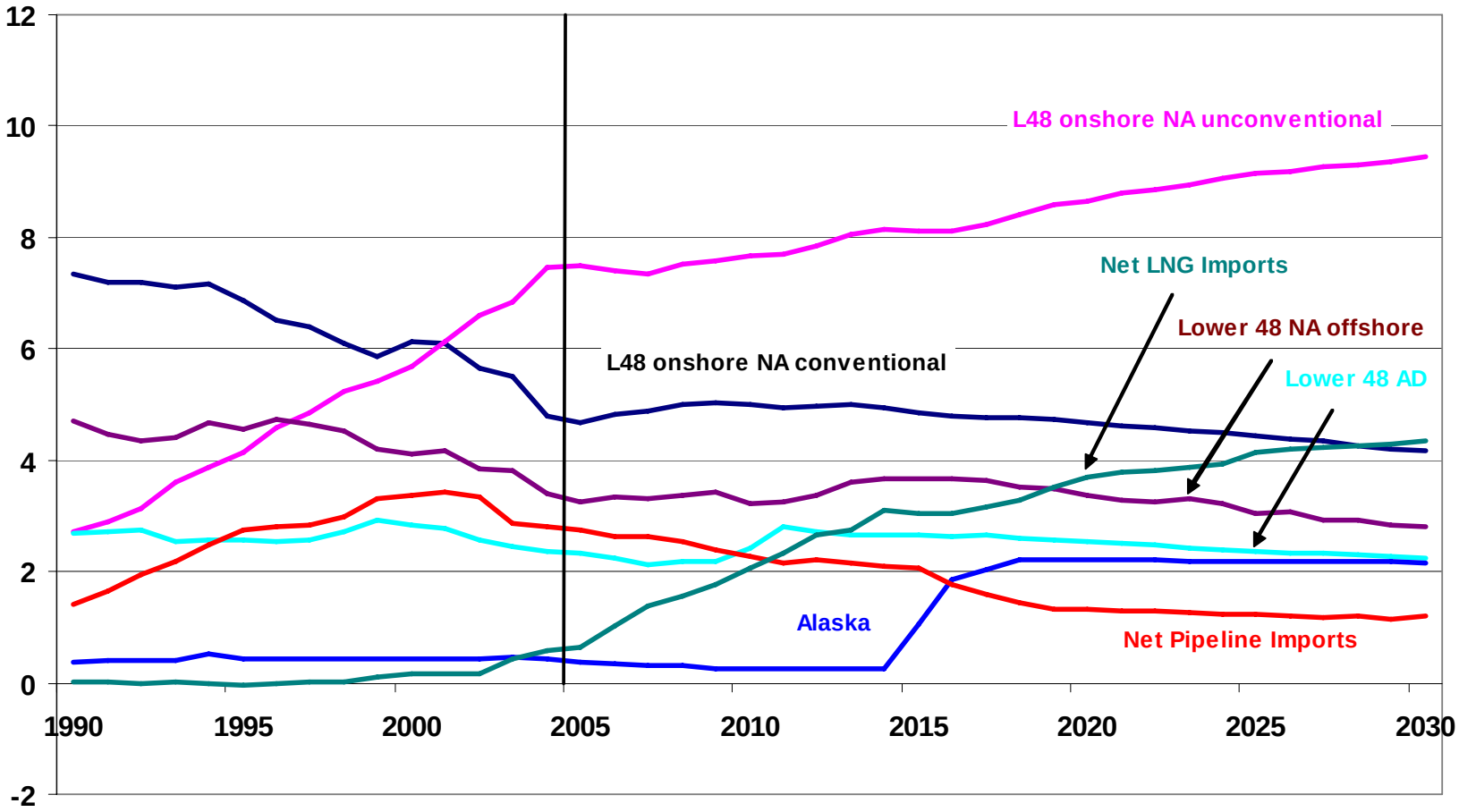


Figure 6. Power Sector Generation by Fuel
(billion kilowatthours)

