S. HRG. 109–362

ENERGY OUTLOOK 2006

HEARING

BEFORE THE

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

ONE HUNDRED NINTH CONGRESS

SECOND SESSION

TO

DISCUSS THE ENERGY INFORMATION ADMINISTRATION'S 2006 ANNUAL ENERGY OUTLOOK ON TRENDS AND ISSUES AFFECTING THE UNITED STATES' ENERGY MARKET

FEBRUARY 16, 2006

Printed for the use of the
Committee on Energy and Natural Resources

U.S. GOVERNMENT PRINTING OFFICE

27–065 PDF WASHINGTON : 2006

For sale by the Superintendent of Documents, U.S. Government Printing Office
Internet: bookstore.gpo.gov Phone: toll free (866) 512–1800; DC area (202) 512–1800
Fax: (202) 512–2250 Mail: Stop SSOP, Washington, DC 20402–0001

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ENERGY OUTLOOK 2006

THURSDAY, FEBRUARY 16, 2006

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 2:40 p.m. in room SD–366, Dirksen Senate Office Building, Hon. Pete V. Domenici, chairman, presiding.

OPENING STATEMENT OF HON. PETE V. DOMENICI, U.S. SENATOR FROM NEW MEXICO

The CHAIRMAN. The hearing will please come to order. Senator Bingaman is not here at this moment, but he was here. I was not quite on time, so he had to go somewhere. Now we have representation on both sides and I assume, Senator Akaka, we can proceed; is that right?

Senator AKAKA. Yes.

The CHAIRMAN. All right. First, Mr. Caruso, we are sorry we had to put this hearing off the other day and we will try to hear you today.

For the past 3 years I have observed that the level of concern about energy issues seems to go up as prices have gone up. It is definitely right that our concern should rise with the American consumers who are paying more for home energy and transportation, but I want us all to keep in mind that, in spite of that, for now the economy is strong. However, we need to take whatever steps we can to assure that energy prices do not change that fact if there is anything we can do about it.

So the first step we took in August 2005 was we passed a rather comprehensive bill. It is having some significant impact. I will note, and you can confirm later, that even in your analysis, where it is pretty hard for you to take energy sources that are not yet in existence and expect them, you do expect nuclear power to be online and to be part of the mix in the next 25-year forecast. That is the first time that has happened in quite a while; right, Mr. Caruso?

STATEMENT OF GUY CARUSO, ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, DEPARTMENT OF ENERGY

Mr. CARUSO. That is correct.

The CHAIRMAN. We trust you on your estimate on that one, although I have some very serious concerns about some other parts of your estimate. I hope you are right, but on some of them I really wonder.

First, I am proud of the vote that occurred on that bill of ours, that means that we know how to work together. And it has a lot of provisions in it so I am just going to insert in the record, Senator Bingaman. That helps us in terms of the issues that Mr. Caruso is concerned with.

So given the importance of many of the provisions in the energy bill and in the national security problems, it is imperative that we remain vigilant on the implementation of that act as I see it. Today, as an example, you will tell us that you expect coal use for electricity generation to go from 50 percent to 57 percent by 2030. Given that prediction, it is obvious that we must do many of the things in that Energy Act to ensure cleaner coal and attempt to do better at funding the activities that would get us that. That is not your policy decision, but I think that follows like night from day, based upon your estimates of what we are going to have to use.

It is obvious that much of what we must do, and we have not done enough yet, is we have to address the use of—reducing the use of petroleum products in our transportation sector and we have to look at new places to get crude oil. I have not mentioned it in any big way yet, but I think we have to probably begin to look at it if we are going to try to get where the President suggested on energy dependence, oil dependence, or further. We are probably going to have to look at things like oil shale and the like in the not too distant future.

I am going to skip over the PACE bill, Senator Bingaman, which we all know has some impact on the future. I want to just go to your final assessments here. The outlook that you have here predicts that prices in 2025—you predict that they are going to be $21 higher—that is oil we are talking about—than your last year's prediction. That is a major adjustment in the expected future price of oil and makes me wonder about the reliability of these predictions.

In other words, you had the price going up much more than that by 2025; is that not correct?

Mr. CARUSO. That is correct, chairman.

The CHAIRMAN. What was the number?

Mr. CARUSO. The 2025 number is approximately $21 higher in real terms this year than last year.

The CHAIRMAN. So what is that dollar amount? When you add 21, what is the dollar number?

Mr. CARUSO. The cents per gallon maybe?

The CHAIRMAN. Dollars per barrel.

Mr. CARUSO. Dollars per barrel, it is $57 per barrel WTI.

The CHAIRMAN. So what I am saying is I think that it is going to be higher than that. I do not understand how you get it that low.

Mr. CARUSO. For the record, in nominal dollars, that is $107.

The CHAIRMAN. Yes.

Mr. CARUSO. Sometimes it is hard to think in 2004 dollars.

The CHAIRMAN. Now we have got it.

I wanted to make this last one. You also think that the level of petroleum imports is going to drop from its 2005 forecast of 68 percent to 60 percent by 2025; is that correct?

Mr. CARUSO. That is correct, Mr. Chairman.

The CHAIRMAN. Now, that is not—those are apples and apples. You think we are going to have 8 percent less importation, based upon the starting point and the assessment that you make every year. You use the same assumptions; it is going to go down. Are you going to tell us why in the statement?

Mr. CARUSO. Sure, I would be happy to.

The CHAIRMAN. That is kind of exciting. We do not have to do anything and we could have had a policy saying we are going to reduce it 8 percent, Senator Bingaman, and had a bill, an 8 percent reduction, and passed it, like everybody wants us to be, bold. Then we would have called him up here and said, did we do it?

Senator BINGAMAN. Full credit.

The CHAIRMAN. Full credit.

Okay, Senator Bingaman.

STATEMENT OF HON. JEFF BINGAMAN, U.S. SENATOR FROM NEW MEXICO

Senator BINGAMAN. Mr. Chairman, knowing the way this place operates, there will probably be such a bill introduced before sunset.

Let me thank you for coming and thank you for your good work. But I do not really have a series of questions at this point. Once you give your testimony, I am anxious to understand the assumptions that are built into it and how any of the policies that we adopted last year as part of the energy bill or that we are contemplating adopting here in this second session of this Congress might impact on your assumptions or on your projections. That is going to be the focus of my questions.

Again, thanks for being here.

The CHAIRMAN. Thank you, Senator Bingaman.

Mr. Caruso.

Mr. CARUSO. Mr. Chairman, members of the committee, thank you very much once again for allowing me the opportunity to present the Energy Information Administration's Annual Energy Outlook, which this year for the first time goes to 2030. Mr. Chairman, I also wanted to say that, while I realize this is not a budget hearing, I would be remiss if I did not mention our budget for fiscal year 2007 that Secretary Bodman presented here in this committee last week. It does include an increase over fiscal year 2006 and I, of course, feel it is fully justified. I would certainly be glad to discuss that with you or any other member or staff at another occasion. I just wanted to say that, while I have the floor.

You are absolutely correct in that this year we have reassessed our outlook for world oil prices significantly above what we have been saying in recent outlooks. As you can see from figure 2* in the written testimony, our expectations are that world oil prices will decline somewhat from where they are now over the next decade or so to roughly $47 in 2014 and then rise to $57 in 2030. That, again, is in real terms, in 2004 dollars.

That represents on average about $21 per barrel higher than our reference case of last year. I think this reflects two important things, and they are that investment opportunities on the global market are tighter than we thought a year ago, and costs are higher. Therefore, we think that there will be less increase in produc-

*All figures have been retained in committee files.

tive capacity than we did a year ago, which would lead to higher prices.

Now, you indicated the uncertainty in global markets, and we tried to anticipate that uncertainty by having a range of assumptions. In this case we have a low price case and a higher price case, which range from $34 per barrel in 2030 to $96 per barrel in 2004 dollars. So clearly we agree with you that there is uncertainty, and we have attempted to capture much of that uncertainty by the high and low price cases in this outlook, which we have released just this week.

Natural gas prices also are higher this year than last year, although we do expect them to come down from their current levels of about $7 per 1,000 cubic feet to about $4.50 in the middle of the next decade, rising to about $6 by 2030 in 2004 dollars.

Energy demand—with these kinds of prices, we have slightly slower growth in energy demand, but we still expect an increase in U.S. energy consumption by about one-third between now and 2030. That is about a 1.1 percent increase annually. The strongest growth will be for electricity generation and in the transportation and commercial sectors.

Because of the high prices, total demand is about 6 quadrillion Btus lower than we were saying a year ago. The lower demand results from higher energy prices, lower growth in manufacturing output, more penetration of hybrid and diesel vehicles, and the effect of the Energy Policy Act of 2005, all of which combine to reduce demand by 2030.

The U.S. economy continues to become more energy efficient. Energy intensity, measured as the energy used per dollar of GDP, declines at an average rate of 1.8 percent per year through 2030, due to improved efficiency and shifts in the economy to less energy-intensive goods and services. This combination of higher oil and natural gas prices, technological change, and the effect of EPAct 2005 has the effect of reducing the shares of oil and natural gas in the U.S. energy mix and increasing the shares of coal, nuclear, and renewables in this outlook. Nevertheless, petroleum is expected to remain the primary fuel in the United States economy, as shown in figure 5 in the written testimony. That is mainly because of growth in the transportation sector, which uses more than 70 percent of all of our petroleum.

Improved efficiency helps, but it cannot offset continued growth in travel by our consumers. Hybrid and diesel vehicles will reach 9 and 8 percent, respectively, of new car sales by 2030—a significant increase from where they are this year, less than 1 percent for hybrids, for example—contributing to the increase in efficiency improvements.

Natural gas demand will grow through the next decade or so, but then flatten out. We do think natural gas prices will have an impact on consumption in the industrial and particularly the electric power sectors, and therefore, its use actually peaks and declines during this outlook period.

Coal, as has been mentioned, remains the primary fuel for electric power generation. Its share increases from 50 percent currently to 57 percent in 2030 in this outlook. We also anticipate, with these higher real prices for crude oil, that there will become a market for coal-to-liquids at the latter part of this period, and we do anticipate coal production to increase from 1,100 million short tons this year to about 1,800 million short tons in 2030, with about 190 million tons going to coal-to-liquids. That would produce about 800,000 barrels a day of mainly diesel fuel from coal-to-liquids plants that would contribute to our petroleum demand.

Nuclear generation is expected to increase in this forecast, going from about 100 gigawatts currently to 109 gigawatts. In the side cases, which allow for advanced technology and lower costs, the increase in nuclear power generation would be significantly more than in the reference case.

U.S. petroleum demand grows from about 21 million barrels a day this year to 27.6 million barrels a day in the forecast in 2030. Domestic production in the near term will actually increase as we bring on deepwater projects in the Gulf of Mexico, but over the long term it will decline again, so that our imports of petroleum as a share of total consumption will go from 58 percent in 2004 to about 62 percent in the reference case.

Now, as I mentioned, we have a low price case and a high price case. In those cases, the oil import dependence would be 53 percent in the high price case and 68 percent in the low price case. So price does make a significant difference and it would make a significant difference in terms of alternative liquids from coal and natural gas, as I mentioned.

Now, for natural gas production, we do think it will increase in the near term, but decline between 2020 and 2030, and therefore there will be a need for significant imports of natural gas. Net pipeline imports from Canada will decline due to resource depletion in western Canada and the need for Canadian domestic consumption. Therefore, LNG will rise substantially, from .6 trillion cubic feet in 2004 to 4.4 trillion cubic feet in the reference case in this outlook.

We do think new facilities to regasify that LNG, in addition to the ones under construction now and the expansion of existing onshore facilities, will be built to serve the gulf coast, Florida, southern California and New England. We also anticipate the Alaska Natural Gas Pipeline will be onstream in 2015 in this outlook.

For electricity generation, we have a 50 percent increase between now and 2030, and coal will supply about 70 percent of that increase under these assumptions. Nuclear generation, as I mentioned, will increase and renewable generation will increase as well, in part due to EPAct 2005 and the various State energy renewable portfolio standard rules and legislation, but will still remain at about 9 percent of total generation.

The Clean Air Interstate Rule and the Clean Air Mercury Rule, issued in March 2005, are expected to substantially reduce power plant emissions of sulfur dioxide, nitrogen oxide, and mercury over the next 25 years. But we do think this can be done without a significant increase in electricity prices.

Mr. Chairman, with this very brief overview of the comprehensive Annual Energy Outlook, I would be pleased to attempt to answer any questions that you or any other committee members may have at this time. Thank you.

[The prepared statement of Mr. Caruso follows:]

PREPARED STATEMENT OF GUY CARUSO, ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, DEPARTMENT OF ENERGY

Mr. Chairman and Members of the Committee: I appreciate the opportunity to appear before you today to discuss the long-term outlook for energy markets in the United States.

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. ETA's baseline projections on energy trends are widely used by government agencies, the private sector, and academia for their own energy analyses. 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.

The *Annual Energy Outlook* (*AEO*) provides projections and analysis of domestic energy consumption, supply, prices, and energy-related carbon dioxide emissions through 2030. The *Annual Energy Outlook 2006* (*AEO2006*) is based on Federal and State laws and regulations in effect on October 1, 2005. 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* includes consideration of the impact of the Energy Policy Act of 2005 (EPACT2005), signed into law August 8, 2005. Consistent with the general approach adopted in the AEO, the reference case does not consider those sections of EPACT2005 that require appropriations for implementation or sections with highly uncertain impacts on energy markets. For example, EIA does not try to anticipate the policy response to the many studies required by EPACT2005 or the impacts of the research and development funding authorizations included in the law. The *AEO2006* reference case only includes those sections of EPACT2005 that establish specific tax credits, incentives, or standards—about 30 of the roughly 500 sections in the legislation. These provisions include the extension and expansion of the Federal tax credit for renewable generation through 2007 and incentives intended to stimulate the development of advanced coal and nuclear plants.

EPACT2005 also has important implications for energy consumption in the residential and commercial sectors. In the residential sector, EPACT2005 sets efficiency standards for torchiere lamps, dehumidifiers, and ceiling fans and creates tax credits for energy-efficient furnaces, water heaters, and air conditioners. It also allows home builders to claim tax credits for energy-efficient new construction. In the commercial sector, the legislation creates efficiency standards that affect energy use in a number of commercial applications. It also includes investment tax credits for solar technologies, fuel cells, and microturbines. These policies are expected to help reduce energy use for space conditioning and lighting in both sectors.

The *AEO2006* is not meant to be an exact prediction of the future but represents 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 and subject to many random events that cannot be foreseen such as weather, 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 complete *AEO2006*, which EIA is releasing this week, includes a large number of alternative cases intended to examine these uncertainties. The following discussion summarizes the highlights from the *AEO2006* reference case for the major categories of U.S. energy prices, demand, and supply and also includes the results of some alternative cases.

U.S. ENERGY OUTLOOK

Energy Prices

EIA has reassessed its long-term outlook on energy prices for the *AEO2006* reference case (Figure 1*), including much higher world oil prices than in recent *AEO*s. World oil markets have been extremely volatile for the past several years, and the reference case oil price path in recent *AEO*s did not fully reflect the causes of that

*All figures have been retained in committee files.

volatility and their implications for future oil prices. In the *AEO2006* reference case, world oil supplies are assumed to be tighter, as the combined productive capacity of the members of the Organization of the Petroleum Exporting Countries (OPEC) does not increase as much as previously projected.

In the *AEO2006*, world crude oil prices, which are now expressed by EIA in terms of the average price of imported low-sulfur crude oil to U.S. refiners, are projected to fall from current levels to about $47 per barrel in (2004 dollars) in 2014, then rise to $54 per barrel in 2025 and $57 per barrel in 2030. The projected price in 2025 is about $21 per barrel higher than projected in last year's reference case (Figure 2).

Geopolitical trends, the adequacy of investment and the availability of crude oil resources and the degree of access to them, are all inherently uncertain. To evaluate the implications of uncertainty about world crude oil prices, the *AEO2006* includes two other price cases, a high price case and a low price case, based on alternative world crude oil price paths. The cases are designed to address the uncertainty about the market behavior of OPEC. Although the price cases reflect alternative long term trends, they are not designed to reflect short-term, year-to-year volatility in world oil markets, nor are they intended to span the full range of possible outcomes. In the low price case, world crude oil prices are projected to decline gradually to $34 per barrel (2004 dollars) through 2020 and then remain at that level through 2030. In the high price case, oil prices grow throughout the projection horizon, reaching more than $96 per barrel (2004 dollars) in 2030.

In the *AEO2006* reference case, average wellhead prices for natural gas in the United States decline from $5.49 per thousand cubic feet (2004 dollars) in 2004 to $4.46 per thousand cubic feet in 2016 as the availability of new import sources and increased drilling expand available supply. After 2016, wellhead prices are projected to increase gradually, reaching $5.92 per thousand cubic feet in 2030. Growth in liquefied natural gas (LNG) imports, Alaskan production, and lower-48 production from unconventional sources are not expected to increase sufficiently to offset the impacts of resource depletion and increased demand in the lower-48 States. Projections of wellhead prices in the low and high price cases reflect alternative assumptions about the cost and availability of natural gas, including imports of LNG. In the low price case, the average wellhead price is projected to decline more rapidly through 2015 than in the reference case, then increases more slowly to 2030, reaching $4.97 per thousand cubic feet (2004 dollars). In the high price case, the pattern is reversed, and the projected wellhead price reaches $7.71 per thousand cubic feet in 2030.

In the *AEO2006*, continued increases in coal production, including an increase in relatively high-cost eastern coal, result in a gradual increase in the average minemouth price from $20.07 per ton (2004 dollars) in 2004 to $22.23 per ton in 2010. After 2010, the price declines gradually to $20.20 in 2020, as the average utilization of mining capacity and the production share of higher-cost Central Appalachian coal decline. Between 2020 and 2030, prices are projected to increase as rising natural gas prices and the need for baseload generating capacity lead to the construction of many new coal-fired generating plants. The substantial investment in new mining capacity during this period, combined with low productivity growth and rising utilization of mining capacity, lead to a recovery in the average minemouth coal price to $21.73 per ton (2004 dollars) in 2030, just under the 2010 average.

Average delivered electricity prices are projected to decline from 7.6 cents per kilowatt-hour (2004 dollars) in 2004 to a low of 7.1 cents per kilowatt-hour in 2015 as a result of an increasingly competitive generation market and a decline in natural gas prices. After 2015, average real electricity prices are projected to increase, reaching 7.5 cents per kilowatt-hour in 2030.

Energy Consumption

Total energy consumption is projected to grow at about one-third the rate (1.1 percent per year) of gross domestic product (GDP), with the strongest growth in energy consumption for electricity generation and transportation and commercial uses. Transportation energy demand is expected to increase from 27.8 quadrillion British thermal units (Btu) in 2004 to 39.7 quadrillion Btu in 2030, an average growth rate of 1.4 percent per year (Figure 3). Most of the growth in demand between 2004 and 2030 occurs in light-duty vehicles (57 percent of total growth), followed by heavy truck travel (24 percent of growth) and air travel (11 percent of growth). Delivered commercial energy consumption is projected to grow at a more rapid average annual rate of 1.6 percent between 2004 and 2030, reaching 12.4 quadrillion Btu in 2030, consistent with growth in commercial floorspace. The most rapid increase in commercial energy demand is projected for electricity used for office equipment, computers, telecommunications, and miscellaneous small appliances.

Delivered industrial energy consumption is projected in the *AEO2006* to reach 32.2 quadrillion Btu in 2030, growing at an average rate of 0.9 percent per year between 2004 and 2030, as efficiency improvements in the use of energy only partially offset the impact of growth in manufacturing output. Delivered residential energy consumption is projected to grow from 11.4 quadrillion Btu in 2004 to 14.0 quadrillion Btu in 2030, an average rate of 0.8 percent per year. This growth is consistent with population growth and household formation. The most rapid growth in residential energy demand is projected to be in the demand for electricity used to power computers, electronic equipment, and small appliances.

The reference case includes the effects of several policies aimed at increasing energy efficiency in both end-use technologies and supply technologies, including minimum efficiency standards and voluntary energy savings programs. However, the impact of efficiency improvement on energy consumption could differ from what is shown in the reference case, as illustrated in Figure 4 which compares energy consumption in three cases. The 2005 technology case assumes no improvement in the efficiency of available equipment beyond that available in 2005. By 2030, 8 percent more energy (10.3 quadrillion Btu) is required than in the reference case. The high technology case assumes that the most energy-efficient technologies are available earlier with lower costs and higher efficiencies. By 2030, total energy consumption is 8.2 quadrillion Btu, or 6 percent, lower in the high technology case when compared with the reference case.

Total petroleum demand is projected to grow at an average annual rate of 1.1 percent in the *AEO2006* reference case forecast, from 20.8 million barrels per day in 2004 to 27.6 million barrels per day in 2030 (Figure 5) led by growth in transportation uses, which account for 66 percent of total petroleum demand in 2004, increasing to 72 percent in 2030. Improvements in the efficiency of vehicles, planes, and ships are more than offset by growth in travel. In the low and high price cases, petroleum demand in 2030 ranges from 29.6 to 25.2 million barrels per day, respectively.

Total demand for natural gas is projected to increase at an average annual rate of 1.2 percent from 2004 to 2020, then remain relatively flat through 2030. With continued growth in natural gas prices in the latter half of the projection, natural gas is expected to lose market share to coal in the electric power sector. Natural gas use in the power sector is projected to decline by 14 percent between 2020 and 2030.

Total coal consumption is projected to increase from 1,104 million short tons in 2004 to 1,784 million short tons in 2030, growing by 1.9 percent per year. About 92 percent of the coal is currently used for electricity generation. Coal remains the primary fuel for electricity generation and its share of generation (including end-use sector generation) is expected to increase from about 50 percent in 2004 to 57 percent in 2030. Total coal consumption in the electric power sector is projected to increase by an average of 1.5 percent per year, from 1,015 million short tons in 2004 to 1,502 million short tons in 2030. Another fast growing market for coal is expected in coal-to-liquids (CTL) plants. These plants convert coal to synthetic gas and create clean diesel fuel, while producing surplus electricity as a byproduct. In the reference case, coal use in CTL plants is projected to reach 190 million short tons by 2030, or 11 percent of the total coal use. In the high price case, coal used in CTL plants is projected to reach 420 million short tons. In the low price case, however, the plants are not expected to be economical within the 2030 time frame.

Total electricity consumption, including both purchases from electric power producers and on-site generation, is projected to grow from 3,729 billion kilowatt-hours in 2004 to 5,619 billion kilowatt-hours in 2030, increasing at an average rate of 1.6 percent per year. The most rapid growth (2.2 percent per year) occurs in the commercial sector, as building floorspace is expanded to accommodate growing service industries. Growing use of electricity for computers, office equipment, and small electrical appliances is partially offset in the *AEO2006* forecast by improved efficiency. EPACT2005 sets residential efficiency standards for torchiere lamps, dehumidifiers, and ceiling fans and creates tax credits for energy-efficient furnaces, water heaters, and air conditioners. It also allows home builders to claim tax credits for energy-efficient new construction. In the commercial sector, the law creates efficiency standards that affect energy use in a number of commercial applications.

Total marketed renewable fuel consumption, including ethanol for gasoline blending, is projected to grow by 2.0 percent per year in the reference case, from 6.0 quadrillion Btu in 2004 to 10.0 quadrillion Btu in 2030, largely as a result of State mandates for renewable electricity generation and the effect of production tax credits. About 60 percent of the projected demand for renewables in 2030 is for grid-related electricity generation (including combined heat and power), and the rest is for dispersed heating and cooling, industrial uses, and fuel blending.

Energy Intensity

Energy intensity, as measured by primary energy use per dollar of GDP (2000 dollars), is projected to decline at an average annual rate of 1.8 percent, with efficiency gains and structural shifts in the economy offsetting growth in demand for energy services (Figure 6). The projected rate of energy intensity decline in the *AEO2006* approximately matches the decline rate between 1992 and 2004 (1.9 percent per year). Energy-intensive industries' share in overall industrial output is projected to fall at an average rate of 0.8 percent per year, a slower decline rate than the 1.3 percent per year experienced from 1992 to 2004.

Historically, energy use per person has varied over time with the level of economic growth, weather conditions, and energy prices, among many other factors. During the late 1970s and early 1980s, energy consumption per capita fell in response to high energy prices and weak economic growth. Starting in the late 1980s and lasting through the mid-1990s, energy consumption per capita increased with declining energy prices and strong economic growth. Per capita energy use is projected to increase by an average of 0.3 percent per year between 2004 and 2030 in the *AEO2006* reference case, with relatively high energy prices moderating the demand for energy services and promoting interest in efficiency improvements in buildings, transportation, and electricity generation.

Energy Production and Imports

Total energy consumption is expected to increase more rapidly than domestic energy supply through 2030. As a result, net imports of energy are projected to meet a growing share of energy demand.

Petroleum. Projected U.S. crude oil production increases from 5.4 million barrels per day in 2004 to a peak of 5.9 million barrels per day in 2014 as a result of increased production offshore, predominantly in the deep waters of the Gulf of Mexico. Beginning in 2015, U.S. crude oil production is expected to decline, falling to 4.6 million barrels per day in 2030. Total domestic petroleum supply (crude oil, natural gas plant liquids, refinery processing gains, and other refinery inputs), increases from 8.6 million barrels per day in 2004 to a peak of 10.5 million barrels per day in 2021, then remains at about that level through 2030. Production from coal liquefaction compensates for a decline in crude oil production in the latter half of the projection period.

In 2030, net petroleum imports, including both crude oil and refined products on the basis of barrels per day, are expected to account for 62 percent of demand in the reference case, up from 58 percent in 2004 (Figure 7). Under alternative oil price projections, the 2030 import fraction ranges from 68 in the low price case to 53 percent in the high price case. Figure 8 compares the impact of the *AEO2006* reference, high price, and low price cases on U.S. oil production, consumption, and imports.

In the U.S. energy markets, the transportation sector consumes about two-thirds of all petroleum products and the industrial sector about one-quarter. The remaining 10 percent is divided among the residential, commercial, and electric power sectors. With limited opportunities for fuel switching in the transportation and industrial sectors, large price-induced changes in U.S. petroleum consumption are unlikely, unless changes in petroleum prices are very large or there are significant changes in the efficiencies of petroleum-using equipment.

Higher crude oil prices spur greater exploration and development of domestic oil supplies, reduce demand for petroleum, and slow the growth of oil imports in the high price case compared to the reference case. Total domestic petroleum supply in 2030 is projected to be 1.5 million barrels per day (15 percent) higher in the high price case than in the reference case. Production in the high case includes 1.9 million barrels per day in 2030 of synthetic petroleum fuel produced from coal and natural gas, compared to 0.8 million barrels per day in the reference case (Figure 9). Total net imports in 2030, including crude oil and refined products, are reduced from 17.2 million barrels per day in the reference case to 13.3 million barrels per day in the high price case.

Natural Gas. Domestic dry natural gas production is projected to increase from 18.5 trillion cubic feet in 2004 to 21.6 trillion cubic feet in 2019, before declining to 20.8 trillion cubic feet in 2030 in the *AEO2006* reference case (Figure 10). Lower-48 offshore production is projected to fall slightly from the 2004 level of 4.3 trillion cubic feet and then grow steadily through 2015, peaking at 5.1 trillion cubic feet as new resources come on line in the Gulf of Mexico. After 2015, lower-48 offshore production declines to 4.0 trillion cubic feet in 2030. Unconventional natural gas production is projected to grow from 7.5 trillion cubic feet in 2004 to 9.5 trillion cubic feet in 2030. With completion of an Alaskan natural gas pipeline in 2015, total Alaskan production is projected to increase from 0.4 trillion cubic feet in 2004 to 2.2 trillion cubic feet in 2018 and to remain at about that level through 2030.

Net pipeline imports are expected to decline from 2004 levels of 2.8 trillion cubic feet to about 1.2 trillion cubic feet by 2030 due to resource depletion and growing domestic demand in Canada. The *AEO2006* reflects an expectation that growth in Canada's unconventional natural gas production, primarily from coal seams, will not be adequate to offset a decline in conventional production.

To meet a projected demand increase of 4.5 trillion cubic feet from 2004 to 2030 and to offset an estimated 1.6 trillion cubic feet reduction in pipeline imports, the United States is expected to depend increasingly on imports of LNG. LNG imports in the *AEO2006* reference case are projected to increase from 0.6 trillion cubic feet in 2004 to 4.4 trillion cubic feet 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. LNG imports in 2030 in the high price case, where expected natural gas demand is lower, are projected at 1.9 trillion cubic feet, less than half of the 4.4 trillion cubic feet projected in the reference case.

One area of uncertainty examined through sensitivity cases regards the rate of technological progress and its affect on future natural gas supply and prices. Technological progress affects natural gas production by reducing production costs and expanding the economically recoverable natural gas resource base. In the slow oil and gas technology case, advances in exploration and production technologies are assumed to be 50 percent slower than those assumed in the reference case, which are based on historical rates. As a result, domestic natural gas development costs are higher, production is lower, wellhead prices are higher at $6.36 per thousand cubic feet in 2030 (compared to $5.92 in the reference case) (2004 dollars), natural gas consumption is reduced, and LNG imports are higher than in the reference case. In 2030, natural gas production is 18.8 trillion cubic feet (10 percent lower than in the reference case), net natural gas imports are 6.4 trillion cubic feet (14 percent higher), and domestic natural gas consumption is 25.6 trillion cubic feet (5 percent lower). Conversely, the rapid technology case assumes 50 percent faster improvement in technology. In that case, natural gas production in 2030 is 24.4 trillion cubic feet (17 percent higher than in the reference case), net natural gas imports are 4.5 trillion cubic feet (20 percent lower), domestic natural gas consumption is 29.4 trillion cubic feet (9 percent higher), and the average wellhead price is $5.20 per thousand cubic feet.

Coal. As domestic coal demand grows in the *AEO2006* forecast, U.S. coal production is projected to increase at an average rate of 1.6 percent per year, from 1,125 million short tons in 2004 to 1,703 million short tons in 2030. Production from mines west of the Mississippi River is expected to provide the largest share of the incremental coal production. In 2030, nearly two-thirds of coal production is projected to originate from the western States (Figure 11).

Electricity Generation

In the *AEO2006* reference case, total electricity generation increases by 50 percent between 2004 and 2030, growing at an average rate of 1.6 percent per year. Coal is projected to supply about 70 percent of the increase in electricity generation (including generation in the end-use sectors) from 2004 to 2030. Generation from coal is projected to grow from about 1,970 billion kilowatt-hours in 2004 to 3,380 billion kilowatt-hours in 2030 in the reference case. In 2030 coal is projected to meet 57 percent of generation, up from 50 percent in 2004 (Figure 12). Between 2004 and 2030, *AEO2006* projects that 174 gigawatts of new coal-fired generating capacity will be constructed, including 19 gigawatts at coal-to-liquids plants.

Generation from natural gas is projected to increase from about 700 billion kilowatt-hours in 2004 to 1,102 billion kilowatt-hours in 2020, but decline by 10 percent between 2020 and 2030 in the face of growing natural gas prices and the availability of a new generation of coal plants. The natural gas share of electricity generation is projected to decline from 18 percent in 2004 to 17 percent in 2030.

The use of renewable technologies for electricity generation is projected to grow, stimulated by improved technology, higher fossil fuel prices, and extended tax credits in EPACT2005 and in State renewable energy programs (renewable portfolio standards, mandates, and goals). The expected impacts of State renewable portfolio standards, which specify a minimum share of generation or sales from renewable sources, are included in the projections. The *AEO2006* reference case also includes the extension and expansion of the Federal tax credit for renewable generation through December 31, 2007, as enacted in EPACT2005. Total renewable generation in the *AEO2006* reference case, including hydroelectric power and renewables-fueled combined heat and power generation, is projected to grow by 1.7 percent per year, from 358 billion kilowatt-hours in 2004 to 559 billion kilowatt-hours in 2030. The renewable share of electricity generation is projected to remain at about 9 percent of total generation from 2004 to 2030.

Nuclear generating capacity in the *AEO2006* is projected to increase from about 100 gigawatts (about 10 percent of total U.S. generating capacity) in 2004 to 109 gigawatts in 2019 and to remain at that level through 2030. The total projected increase in nuclear capacity between 2004 and 2030 includes 3 gigawatts expected to come from uprates of existing plants that continue operating and 6 gigawatts of capacity at newly constructed power plants, stimulated by the provisions in EPACT2005. The new nuclear plants are expected to begin operation between 2014 and 2020. Total nuclear generation is projected to grow from 789 billion kilowatt-hours in 2004 to 871 billion kilowatt-hours in 2030 in the *AEO2006*. The share of electricity generated from nuclear is projected to decline from 20 percent in 2004 to 15 percent in 2030.

The *AEO2006* reference case assumptions for the cost and performance characteristics of new nuclear technologies are based on cost estimates by government and industry analysts, allowing for uncertainties about new, unproven designs. Two advanced nuclear cost cases analyze the sensitivity of the projections to lower costs for new nuclear power plants. The advanced nuclear cost case assumes capital and operating costs 20 percent below the reference case in 2030, reflecting a 31-percent reduction in overnight capital costs from 2006 to 2030. The vendor estimate case assumes reductions relative to the reference case of 18 percent initially and 44 percent by 2030. These costs are consistent with estimates from British Nuclear Fuels Limited for the manufacture of its AP 1000 advanced pressurized-water reactor. Cost and performance characteristics for all other technologies are assumed to be the same as those in the reference case.

Projected nuclear generating costs in the advanced nuclear cost cases are competitive with the generating costs projected for new coal-and natural-gas-fired units toward the end of the projection period. In the advanced nuclear cost case, 34 gigawatts of new nuclear capacity are added by 2030, while the greater cost reductions in the vendor estimates case bring on 77 gigawatts by 2030 (Figure 13). The additional nuclear capacity displaces primarily new coal capacity.

The Clean Air Interstate Rule and the Clean Air Mercury Rule, issued by the U.S. Environmental Protection Agency in March 2005, are expected to result in large reductions of emissions from power plants. In the *AEO2006* reference case, projected emissions of sulfur dioxide from electric power plants in 2030 are 66 percent lower than the 2004 level, emissions of nitrogen oxide are 42 percent lower, and emissions of mercury are 71 percent lower.

Energy-Related Carbon Dioxide Emissions

Carbon dioxide emissions from energy use are projected to increase from 5,900 million metric tons in 2004 to 8,114 million metric tons in 2030 in the *AEO2006*, an average annual increase of 1.2 percent (Figure 14). The energy-related carbon dioxide emissions intensity of the U.S. economy is projected to fall from 550 metric tons per million dollars of GDP in 2004 to 351 metric tons per million dollars of GDP in 2030, an average decline of 1.5 percent per year. Projected increases in carbon dioxide emissions primarily result from a continued reliance on coal for electricity generation and on petroleum fuels in the transportation sector.

CONCLUSIONS

Continuing economic growth in the United States is expected to stimulate more energy demand, with fossil fuels remaining the dominant source of energy. The U.S. dependence on foreign sources of oil is expected to continue increasing. Petroleum imports that accounted for 58 percent of total U.S. petroleum demand in 2004 are expected to account for 62 percent of total demand by 2030 in our reference case, with most of the increase resulting from increased consumption for transportation.

Furthermore, although natural gas production in the United States is expected to increase, natural gas imports, particularly LNG, are expected to grow rapidly. Total net LNG imports in the United States and the Bahamas are projected to increase from 0.6 trillion cubic feet in 2004 to 4.4 trillion cubic feet in 2030 in our reference case. In the United States, reliance on domestic natural gas supply to meet demand is projected to fall from 83 percent in 2004 to 78 percent in 2030. The growing dependence on imports in the United States occurs despite efficiency improvements in both the consumption and the production of natural gas.

This concludes my testimony, Mr. Chairman and members of the Committee. I will be happy to answer any questions you may have.

The CHAIRMAN. Thank you very much.

I might say to the Senators, since there are so many here, I am sure that that indicates a genuine interest in inquiring. So I want to just be very brief and then, if you do not mind, Senator Craig, I might even, if you can be here a while—you cannot?

Senator CRAIG. I have to leave here at 3:30.

The CHAIRMAN. Okay. Can one of the two Senators here be here for a while this afternoon?

Senator MURKOWSKI. Yes.

The CHAIRMAN. Then I would leave for a little bit and you can take over, and then Senator Bingaman and the Democrats can stay as long as they like, and I can return.

I just have two questions I want to be sure that I understand. In 2005 you predicted the price of oil 25 years down the line or whatever—what is your number, 25 years?

Mr. CARUSO. In 2005 our final year was 2025, and the outyear price was about $36.

The CHAIRMAN. So how far off were you then?

Mr. CARUSO. Well, we have reassessed that outlook and we now think that a more plausible reference case outlook is about $20 more than what we were saying a year ago. So for 2025 it is actually about $54 compared with $33 that we were saying last year.

The CHAIRMAN. Tell me again, because I am not understanding. When you last gave us an assessment, you told us 25 years from now the price of oil is going to be what?

Mr. CARUSO. Our reference case was the expectation prices would go back down to roughly $30, $33 to be precise, in 2025.

The CHAIRMAN. Now you are giving us——

Mr. CARUSO. Now what we are saying is, having looked at what investment plans are—not only OPEC, but non-OPEC countries—and issues with respect to accessibility to the resource base and higher cost of doing business in the commodities boom that we have witnessed, we now believe that a more plausible reference case is on average about $50. But recognizing the uncertainty that you mentioned, we also have a low price case of $33 and a high price case of $97. So we hope that those three cases would encompass the range of most possibilities over the next 20, 25 years.

The CHAIRMAN. Well, I would hope so, too. Because, obviously, if that is the range, for anybody who has to base their business judgments on that, it is not very helpful.

In any event, let me boil it down to less years. Do you give some estimate of what the price might be next year or the year after, close term?

Mr. CARUSO. Sure.

The CHAIRMAN. Is the price going up or down in the next 2 or 3 years?

Mr. CARUSO. We are looking at, in the next 2 years, $60 to $65 as a range in our Short-Term Energy Outlook. However, we do think as you look out 3 to 5 years that the investments that are now underway will bear fruit, and that the productive capacity growth in the country, in the world, will allow some downward pressure on prices over the next, I would say, 3 to 5 years.

The CHAIRMAN. So even with the world situation being what it is, which you must take into consideration, you are not, as our expert here, predicting a dramatic increase in the price of oil over the next 2, 3, 4, 5 years? Is that a fair statement?

Mr. CARUSO. That is correct, in a non-disrupted market.

The CHAIRMAN. Now, let us move to the domestic. You have something to say about the non-imported oil, both as to—you talked about how much we are going to produce ourselves; is our production going up or down short-term and long-term?

Mr. CARUSO. In the short term it is going up. We anticipate the deepwater projects in the Gulf of Mexico between 2006 and about 2012 will actually see an increase, a small increase, but nevertheless, not a decline, which we have seen now for the last 2 decades. However, beginning about the middle of the next decade it will resume its decline, and therefore we anticipate that net oil import dependence will increase over the longer term.

The CHAIRMAN. I was not going to take time, but I think I will go to natural gas and do the same thing. Tell us what is going to happen with natural gas today, natural gas 25 years from now, and then natural gas short-term?

Mr. CARUSO. On prices, we think natural gas prices will stay high for the near term, which is probably through 2007 and possibly into 2008. However, beginning in 2008 we do think a significant amount of new LNG projects will be onstream, the regasification projects here, and the liquefaction in Qatar and elsewhere. So we think that prices will start to come down for natural gas in the latter part of this decade. We have it coming down under $5 by 2014, 2015, and then increasing again, as I mentioned, to about $6 by 2030, in 2004 dollars.

On supply, we do think that there is room for growth in domestic gas production, but not nearly enough to meet demand growth. So we have small growth over the next decade or so from unconventional sources, primarily tight sands in the Rocky Mountains, shale gas, and coalbed methane, and the expectation that the Alaska gas line will be onstream beginning in 2015 at about 4.5 Bcf a day.

All of that we think will contribute to a better supply situation. In the long run, we will have to rely on LNG. We are projecting LNG imports to exceed 4 trillion cubic feet in the 2020 to 2030 timeframe, up from only about .6 trillion cubic feet in 2004.

The CHAIRMAN. One last question. You mentioned natural gas from shale; if you assume that can work, is there anything different about assuming that it would work for the production of oil?

Mr. CARUSO. Yes. Oil technology as we know it today—and there are companies, as you know, that are possibly on the verge of making some significant breakthroughs, but as we know it today, shale oil in our model is not competitive, it cannot be produced at less than about $70 a barrel.

The CHAIRMAN. Thank you very much.

Senator Bingaman.

Senator BINGAMAN. Let me ask a couple of basic questions. You have a chart in here, it is figure 3, energy consumption by fuel. No, let me go instead to figure 6, total energy production and consumption. This is in the forward or the overview at the beginning of your report. Now, the way I read that chart, between 2004 and 2030 you are expecting the gap between consumption and production in the country to widen, so that we will become more dependent on foreign sources.

Mr. CARUSO. That is correct.

Senator BINGAMAN. Now, the President said in his State of the Union speech that he was setting as a goal that we would reduce our imports of oil from the Middle East—I believe I am correct—by 75 percent by 2025. Do you have any chart in here that talks about what you project to be our imports of oil from the Middle East or generally by that time?

Mr. CARUSO. Not in the main report, but we do have some supplemental tables, which are released on the website. I am trying to think. Our expectations of imports from the Persian Gulf region in 2025 are about 3.3 million barrels a day.

Senator BINGAMAN. How does that compare to today?

Mr. CARUSO. Today they are about 2.3.

Senator BINGAMAN. So you expect that the imports from the Middle East will go up fairly significantly between now and 2025?

Mr. CARUSO. Under these assumptions, yes, that is correct, Senator Bingaman. Compared with last year's outlook, that is a significant reduction. We were saying about 6 million barrels a day from the gulf in 2025 in the outlook that we released 1 year ago.

Senator BINGAMAN. And what has caused you to change that outlook so dramatically as far as imports from the Middle East?

Mr. CARUSO. I think two main things. One is that our total consumption of petroleum projected for 2025 is about a million and a half barrels a day, maybe even two million barrels a day lower, and we do have an increase in domestic supply, both conventional as well as, as I mentioned, coal-to-liquids. The big picture is that the net import number is lower by about 3 million barrels a day and, by virtue of the fact that the Middle East is the marginal supplier, with all of non-OPEC producing at full capacity, almost all of the decline comes out of our expectations from the Persian Gulf region.

Senator BINGAMAN. Let me refer you to the chart that you have up here, the capacity additions by year and fuel. I understood you to say that you expect the production or the capacity from nuclear to go from 100, which it is now, 100 gigawatts roughly, up to 109 by 2030?

Mr. CARUSO. That is correct, yes.

Senator BINGAMAN. On that chart, as I understand it, the yellow is supposed to represent the addition of nuclear capacity?

Mr. CARUSO. That is correct.

Senator BINGAMAN. Now, I notice, when I have tried to read it here, unless my eyesight is failing me, you do not have any additional nuclear capacity being added after about the year 2017 for the next 12 years or 13 years after that. Why is that stalling out, in your view?

Senator Domenici has been a big champion of the nuclear industry and I have certainly supported trying to expand their capacity. But you are estimating that—this is taking into account what we did in last year's energy bill. But, regardless of that, as I see it, you are saying there is going to be a 9 percent increase in the amount of electricity produced from nuclear power in the next 25 years. That is not a big increase.

Mr. CARUSO. Just to clarify, going from 100 gigawatts capacity to 109 gigawatts capacity is comprised of 6 gigawatts directly related to the provisions of EPAct 2005 and the production tax credits, which, as I understand it, expire or these new nuclear plants have to come onstream by 2019, I believe. So that is why we have the increases you do see before 2018.

Senator BINGAMAN. So you assume when those expire there is not going to be any more construction of nuclear capacity?

Mr. CARUSO. Under the assumptions we have right now, coal gets—as you can see from that chart, the blue areas—the lion's share of the new capacity after 2020.

Senator BINGAMAN. So you are basically assuming—or your conclusion is that absent those tax incentives that we put in last year's bill, coal is a much more economic way to produce electricity in the future than is nuclear?

Mr. CARUSO. Yes, sir.

Senator BINGAMAN. Is that fair?

Mr. CARUSO. That is absolutely correct, and the other 3 gigawatts through the nuclear is through up-rates of the existing plants.

Now, in our outlook, which we released this week, we run two alternative cases, advanced nuclear technology and vendor cost estimates. In those cases, which assume much lower capital costs for new nuclear plants, that 6 gigawatts of new capacity goes up to 34 gigawatts in one case and 77 in the case where the vendors' cost estimates are accurate. Vendors of nuclear plants have much lower cost estimates than we believe are plausible, but in order to, I think——

Senator BINGAMAN. So what you are saying is that there is another estimate, that you just do not think is a valid estimate of the cost of doing additional nuclear capacity?

Mr. CARUSO. Yes, Senator.

Senator BINGAMAN. I think my time is up. Thank you very much.

Senator MURKOWSKI [presiding]. Go ahead, please.

Senator CRAIG. I think Senator Akaka was here before me.

Senator MURKOWSKI. Senator Akaka.

STATEMENT OF HON. DANIEL K. AKAKA, U.S. SENATOR FROM HAWAII

Senator AKAKA. Thank you very much, Mr. Chairman.

Welcome, Mr. Caruso. Good to have you here, and I want to thank you for the Energy Information Administration's outlook report of 2006 and sharing with us your research analysis that will be useful tools for us in our decisionmaking here.

As you know, Hawaii's energy situation is unique because we rely almost 100 percent on oil for our generation of electricity and gasoline, and almost all of our energy needs, of course, are imported. So we have to face that. Last year you testified before this committee that ultimately gas hydrates should be a large supply of natural gas. At the same time, you expressed some pessimism regarding the development of the necessary technology.

Along with my colleague, Senator Murkowski, I believe that gas hydrates are a potentially invaluable resource. My question to you is, did you include gas hydrate reserves in your calculations regarding domestic supplies of natural gas?

Mr. CARUSO. No, Senator Akaka. The gas hydrates technology remains unproven and too expensive, in our view, to be a significant supplier of natural gas in the timeframe that we are looking at here, which is 2030.

Senator AKAKA. Just to be specific, this is part of what we know as methane, methane hydrates.

Mr. CARUSO. Yes.

Senator AKAKA. And I know the technology is not here and it is down a few years before we can get to it. Yet, as you said, we have a huge supply of that.

According to your Annual Energy Outlook, there will be a growth in the use of coal—and the graph here shows that very clearly—and coal for electricity production. Particularly, again, what impact do you think this trend will have on the cost of electricity in the State of Hawaii, where virtually all electricity, as I pointed out, comes from oil-fired plants?

Mr. CARUSO. I think, as you point out, since I think more than 80 percent of your electricity is oil-fired steam turbines, we do not anticipate that the developments of coal use increasing elsewhere will have much of an impact on Hawaii. But if, for example, the utilities there were to replace the oil-fired plants with new coal-fired plants, we think, in our model, that the average cost of producing that electricity would go down. However, there is so much investment already in the oil-fired plants, of course, there would be a huge capital cost to those utilities.

So the marginal cost of producing the electricity from coal would be lower, but it would require substantial new investments to replace those existing plants. So we do not anticipate in our outlook that that investment decision will be made.

Senator AKAKA. Your calculations, as you said, show that there would be a savings in using coal. But let me ask you another part of that, and you alluded to this, that there may be other costs, like shipping of coal to Hawaii. We will have to import it. Do you think this might offset any savings?

Mr. CARUSO. Yes, in fact I think that is why we are not assuming any of those investment decisions to be made, because the infrastructure of providing receiving facilities for the coal and new electric power generation units, because of the reasons you just said—the large, up-front, new infrastructure investment that would be needed.

Senator AKAKA. Thank you for your responses. My time has expired. Thank you, Mr. Chairman.

STATEMENT OF HON. LISA MURKOWSKI, U.S. SENATOR FROM ALASKA

Senator MURKOWSKI. Thank you, and I appreciate you, Senator Akaka, bringing up our gas hydrates bill. I think that that is important, that we try to keep that out in the forefront so people do not forget the great potential there.

Mr. Caruso, moving from Hawaii to Alaska and the discussion, your comments about the significance of Alaska's North Slope natural gas coming online and the projection that it will be there by

2015. I want to remain optimistic. The State remains in negotiations for a contract or an agreement to move forward with that, but as of yet we do not have an agreement.

What happens to your forecast, to your projection, if that project slips?

Mr. CARUSO. All other things being equal, the price of gas would be higher without, without that project coming onstream in 2015.

Senator MURKOWSKI. How much cushion do you have? Say we are behind by a year, what would that do? Would that markedly affect the price or would it have to be a significant delay before we would actually see anything reflected in the market?

Mr. CARUSO. I think, for whatever time it is that it is delayed, those years—let us just say instead of 2015 it is 2016. I think that is 1 year of somewhat higher natural gas prices, just isolating that one factor. It means that there is 4.5 Bcf a day that we have to import as, let us say, Qatar LNG, and that will be a bit higher.

Senator MURKOWSKI. Let me ask you, in your report you note the need to bring on additional natural gas imports and you make mention of the existing LNG facilities that we have, the expansions of three or four of them, and the new construction that is coming on line you are anticipating. Given what we will need, what you anticipate we will need because of imports, and given what you know of the existing facilities, do we have enough either on the drawing board or already in existence that we would be able to accept the LNG that we will need coming in?

Mr. CARUSO. As of now, it does look like we have, when you combine the expansion of three of the four onshore facilities, the two that are under construction, and those that FERC or the Coast Guard have already approved, it does look as though the regasification side of this equation is moving actually faster than most analysts thought even 1 year ago and, if anything, now we are a little bit more worried about whether the liquefaction facilities in places like Nigeria or Qatar will be on time to meet the demand.

So I would say on the regas side we are in reasonably good shape, especially since there are facilities in Baja California, Mexico, to serve southern California, and in the Maritimes of Canada, which we now think will be built to serve New England.

Senator MURKOWSKI. You mentioned that if, in fact, the timeline slips on the Alaska natural gas, we have got to figure out a way to meet that difference for the year until the gas comes online. But the reality is these contracts that we are signing, whether it is with Qatar or whomever, for these additional gas supplies, these are not typically contracts for 1 year, these are longer-term contracts.

Mr. CARUSO. That is correct.

Senator MURKOWSKI. This is one of the concerns that I have from Alaska's perspective. We do not want to get aced out by signing onto some long-term contracts in order to meet that short-term differential because we do not have Alaska's gas coming on. That is something that we are working on.

Let me move to oil. As part of your alternative forecast scenarios last year, you looked to ANWR with an alternative forecast that assumes that ANWR is open. You have done that again in this year's forecast. Can you talk about what opening up ANWR with the potential of 10 billion barrels of oil, what it means in terms of your forecast that we have currently before us now?

Mr. CARUSO. Sure. Yes, we would expect that if ANWR were approved it would take about 10 years to get it online, so 2015 or so, and it would ramp up to about 800,000 barrels a day after probably 5 to 7 years of ramp-up. That would reduce the amount of imports barrel-for-barrel. So we think probably instead of 62 percent import dependency, it would reduce that to about 60 percent.

In terms of the price impact, our rough estimate is about a dollar a barrel for every barrel that we consume, and by then, as I mentioned, we would be consuming about 27 million barrels a day. So it is consistent with the reports we have done for this committee and for the House side as well.

Senator MURKOWSKI. Just one last question. Looking at the chart, in terms of where we are importing our oil currently and recognizing that we get about 7.3 percent of our oil demand from Venezuela and Venezuela accounts for a little over 11 percent of our imports, Venezuela is not exactly a comfortable place right now. In terms of what a disruption coming out of Venezuela could mean to your forecast—11 percent of our Nation's imports coming out of Venezuela now—if that were to be shut off, what would that mean to us?

Mr. CARUSO. Well, in the short run, because there is so little spare productive capacity in the world, unless we were to offset that with Strategic Petroleum Reserve or some other——

Senator MURKOWSKI. How could we offset that much?

Mr. CARUSO [continuing]. It would be substantial. We could not offset it in terms of relying on spare capacity in the world because there is only about 1.5 to 2 million barrels a day spare capacity, and most of that is in Saudi Arabia, and that is 45 days away. So clearly there would be an immediate price response.

In terms of the Strategic Petroleum Reserve, we could release that oil, of course. But there is a limit to how much, how long we would be able to replace the missing barrels. It would depend on the duration of the disruption. But nevertheless, we saw in late 2002 and the early part of 2003 how significant the Venezuelan oil was to our refiners. We had a sharp price runup and a decline in inventories, which we have only recently recovered from.

Senator MURKOWSKI. Thank you.

I am sure my time is up, even though there is not a light. Senator Bingaman.

Senator BINGAMAN. Thank you.

Let me ask you, on this chart that you have in here, it is figure 7, energy production by fuel. Again, it is in the overview at the beginning of your report or close to the beginning. I think it is page 8. Now, as I read that chart, it shows non-hydro renewables as increasing until 2030, so that we would continue to be adding capacity in non-hydro renewables each year essentially from now until 2030.

You are also, though, assuming, or at least I believe you are, that the tax incentives that we put into the law this last year expire when we said they would expire, which is the end of next year.

Mr. CARUSO. That is correct.

Senator BINGAMAN. So the production tax credit for wind, the production tax credit for solar, you are assuming that those production tax credits all expire at the end of next year. In spite of that, you believe that there will continue to be additions to capacity for these renewable energy sources. That is very different than what you have assumed with regard to nuclear power. In the case of nuclear power, you have said once the tax incentives go away, we quit building nuclear power, but in the case of renewables, we do continue to build those capacities.

Mr. CARUSO. The main reason for that difference is there are 23 States with renewable portfolio standards and they continue. We assume that they remain in effect. So in those States we see continued growth in non-hydro renewables.

Senator BINGAMAN. I see. Now, the way I read your chart here—again, this one that you have up here on the easel—you have much more of the total addition to capacity coming from renewables in the next couple of years, 2006 and 2007, than you do after that. That, I assume, relates to the fact that we are eliminating those tax incentives or they are scheduled to expire.

I guess the question is, have you done any calculation as to what would be the effect on our addition to capacity of renewable power if we were to extend those tax credits from now to 2030?

Mr. CARUSO. I would have to check on that. We may have done something for the NCEP.

Senator BINGAMAN. The NCEP?

Mr. CARUSO. We may have done some analysis which assumed their continuation as part of the analysis we did for you last year.

Senator BINGAMAN. Okay.

Mr. CARUSO. But I will check on the record for that.

[The information follows:]

Renewable Electricity. [Note, paraphrased question] Has EIA done an analysis of what would be the effect on our addition to capacity of renewable power if we were to extend the renewable electricity production tax credits from now to 2030?

EIA has not conducted an analysis of the impact on renewable generation capacity of an extension of the production tax credit (PTC) through 2030. In January 2006, EIA conducted an analysis of an extension through 2016 of the renewable energy PTC, on behalf of the Congressional Joint Committee on Taxation. This analysis used the *Annual Energy Outlook 2006* reference case as the baseline, and assumed the PTC is structured as currently specified, but with eligibility for facilities entering service by December 31, 2016.

The analysis concludes that an extension of the renewable energy portions of Section 45 of the tax code would result in significant growth in renewable generating capacity and generation.

The biggest growth is seen in wind generation with 244 billion kilowatt-hours in 2016 in the PTC extension case, compared to 56 billion kilowatt-hours in the reference case. Wind capacity has a fairly short lead-time and relatively low-cost resources are available in many parts of the country. Biomass generation also grows substantially, with 63 billion kilowatt-hours in 2016 in the PTC extension case, compared to 50 billion kilowatt-hours in the reference case. Although low-cost biomass fuels are widely available, the technology has longer construction lead-times than wind capacity, and it also receives half of the credit value as wind. Geothermal generation increases to 32 billion kilowatt-hours in 2016 in the PTC extension case, compared to 24 billion kilowatt-hours in the reference case. Geothermal resources are limited both by geography and by the rate of exploitability. Landfill gas and hydroelectric generation also increase slightly with the PTC extension, but the additional resources that can be economically developed by these technologies are limited. Growth in solar generation is not affected by extension of the PTC, because solar technologies are no longer eligible for this tax credit.

Mr. CARUSO. The other comment on the early part of the non-hydro renewables is that we also have in there the renewable fuel standard that is part of that, in that production, in figure 7 on page 8.

Senator BINGAMAN. I see. Okay.

Let me just ask, since you raised the issue of that study you did last year, that NCEP report, the National Commission on Energy Policy, you concluded as part of that study that there would be, I think the phrase you used was no material effect on the economy from the adoption of the recommendations of that NCEP; is there anything in this that would contradict that conclusion, anything in this new report?

Mr. CARUSO. Not that I am aware of.

Senator BINGAMAN. You stick by that conclusion?

Mr. CARUSO. Yes, Senator.

Senator BINGAMAN. You have a section called issues and focus, and you talk about energy technologies on the horizon and advanced technologies for light-duty vehicles. Could you just take a minute to tell me what your conclusions are? I have not had a chance to read any of that yet, but I am interested in knowing if there are some new energy technologies or advanced technologies available for vehicles that would significantly impact any of these projections.

Mr. CARUSO. The answer is that we see a number of new technologies for light-duty vehicles that can substantially increase their efficiency. This outlook already has reasonably good increases in average vehicle efficiency as a result of the change in the mix with more hybrids and diesels. In addition to that, with various new technologies which are enumerated in the report, we do think that that could be increased by at least 10 percent—we have a high technology case in the report, which I believe is about a 10 percent improvement in the average vehicle efficiency from a combination of different technologies with respect to vehicles, which are described in more detail in the report.

Senator BINGAMAN. Have you done any modeling or had any requests to do any modeling related to the increased use of this plug-in technology everyone is—I am reading articles these days about how the next great advance in reducing fuel consumption in the transportation sector may come from adoption of a plug-in technology, so that you have cars with a substantial battery capacity that can operate off of electric power for a significant distance.

Have you looked at that or is that anything that you have the capacity to look at?

Mr. CARUSO. We have not done anything in detail with respect to plug-in hybrids, but certainly we have that capacity. We have looked, again in conjunction with the National Commission on Energy Policy report analysis we did for you, looked at a 36 percent increase in CAFE standards and what the impact of that would be. So we have done some things, but they have not been specifically related to plug-in hybrids.

Senator BINGAMAN [presiding]. Okay. I think, just looking around the table here, it looks as though we are out of Senators. I am informed that the record is going to remain open until the close of business tomorrow and Senators may want to submit questions to you in writing. If you would be willing to answer those, we would appreciate it very much.

Mr. CARUSO. We definitely would do that.

Senator BINGAMAN. Thank you for coming today.

[Whereupon, at 3:35 p.m., the hearing was adjourned.]

APPENDIX

RESPONSES TO ADDITIONAL QUESTIONS

DEPARTMENT OF ENERGY,
CONGRESSIONAL AND INTERGOVERNMENTAL AFFAIRS,
Washington, DC, April 11, 2006.

Hon. PETE V. DOMENICI,
Chairman, Committee on Energy and Natural Resources, U.S. Senate, Washington, DC.

DEAR MR. CHAIRMAN: On February 16, 2006, Guy Caruso, Administrator, Energy Information Administration, testified regarding EIA's Annual Energy Outlook.

Enclosed are answers to 25 questions that were submitted by Senators Craig, Thomas, Talent, Akaka, Salazar, and you to complete the hearing record.

If we can be of further assistance, please have your staff contact our Congressional Hearing Coordinator, Lillian Owen, at (202) 586-2031.

Sincerely,

JILL L. SIGAL,
Assistant Secretary.

[Enclosures.]

RESPONSES TO QUESTIONS FROM SENATOR DOMENICI

OIL PRICES

Question 1. In the EIA "High Oil Price Case", oil prices reach more than $96 (in 2004 dollars) by 2030. What changes between the Reference Case, which predicts prices will be around $57 in 2030, and the High Oil Price Case that accounts for this nearly $40 difference?

Answser. Relative to the Reference Case, the High Price Case assumes that global oil resources are more costly and less abundant and that OPEC members choose to produce oil at a slower rate.

In particular, the High Price Case assumes that (1) the costs of finding and developing the remaining world's oil resources are 15% higher, and (2) the ultimately recoverable reserves are 15% lower than in the Reference Case. The High Price Case also projects in 2030 that OPEC members produce only 31.7 million barrels of oil per day, as opposed to 45.8 million barrels per day in the Reference Case.

Question 2. We have watched oil prices go up on worries about the Iran nuclear situation and react to kidnappings in Nigeria. These events are examples of what analysts often talk about as the "fear premium" on oil. What do you think the fear premium number is today?

Answer. Separating expectations on future events that might affect oil markets from the so-called fundamentals is difficult and imprecise at best. Further separating them and quantifying a risk portion is simply an educated guess.

That said, with the spot price of West Texas Intermediate crude oil at around $61 per barrel as of February 28, EIA estimates that a "premium" of 0 to $5 would seem reasonable, based on EIA's analysis and modeling that suggests a range from the high $50s (West Texas Intermediate) to the low $60s can be explained by the fundamentals, notably tight spare upstream capacity. One way to view the "premium" is that as it fluctuates constantly, so, too, does the demand for inventory shift. Since the end of December, those shifts have occurred not only with changing perceptions on the risk of Iranian disruptions or worsening Nigerian oil flows, but shifting assessments of recent OPEC and non-OPEC volume losses (Russia, North Sea, U.S. Gulf of Mexico, etc.) and their likely duration, weather impacts on Asian and European crude oil/product demand and stocks, and, especially, forthcoming U.S. gasoline tightness as spring approaches.

When WTI rose over $68 per barrel in late January, it would not have been unreasonable to say the risk premium increased to between $5 and $10 per barrel. But with the surge in U.S. gasoline stocks over the last 4 to 6 weeks, and to a lesser extent, the absence of even a seasonal draw in distillate fuel, much of the earlier "fear" of winter pressures compounding an already tight outlook for gasoline has eroded, undercutting margins and crude prices. To some extent, the immediacy of Iranian pressures has also eroded, but how much of the corresponding crude drop can be attributed to Iran, how much to gasoline, and how much to other factors is impossible to know.

Question 3. The lack of world spare oil capacity has been one of the prime factors for today's high oil prices. World spare capacity now is at about 1.5 million barrels a day. What do you think we should expect world spare capacity to be in the next 5, 10, 20 years? Will spare capacity continue to be one of the prime factors affecting oil prices?

Answer. We expect spare oil production capacity to increase over the next few years and to reach a level of 3 to 5 million barrels per day by 2010. After 2010, on average we expect global spare capacity to remain between 3 and 5 million barrels per day during the projection period to 2030. Spare oil production capacity will continue to be one of the prime factors affecting oil prices in the short term, but over the longer term other factors such as resources and other energy alternatives are more important.

REFINERY

Question 1. According to the most recent Summary of Weekly Petroleum Data, total U.S. motor gasoline imports (including both finished gasoline and gasoline blending components) averaged nearly 1.2 million barrels per day. Given that domestic refinery capacity is predicted to grow at about 0.5% annually between 2004 and 2030 and utilization rates are expected to remain around 93% during that time period (according to EIA Reference Case Table Answer), will the United States become increasingly dependent on imports of refined products and how will this effect prices and domestic refineries?

Answer. The EIA projections have always indicated that the U.S. is likely to become somewhat more dependent on product imports. In *AEO2006*, the demand for petroleum products is projected to grow at over 1 percent per year between 2004 and 2030, about twice the rate at which refinery capacity is expected to grow for the same period. If U.S. refinery margins (i.e., the difference between crude oil and petroleum product prices) widen, domestic refinery capacity will expand faster. Refinery margins are determined in international markets and depend on many different variables, including refinery capacity, crude quality, product specification, transportation costs, and fuel costs.

In *AEO2006*, a significant portion of the growth in product imports relative to *AEO2005* resulted from a projected increase in imports of natural gas liquids (NGL). Lower projected total domestic natural gas production in *AEO2006* coupled with an assumed decrease in the NGL content of unconventional sources have resulted in significantly lower domestic NGL production. The shortfall is compensated for with an increase in NGL imports.

Finally, *AEO2005* also contained assumptions more favorable to the expansion of domestic refineries than to importing products, including the assumption that global petroleum product providers would be reluctant or unable to supply MTBE-free reformulated gasoline and ultra-low-sulfur diesel at attractive prices.

NATURAL GAS

Question 1. Current natural gas storage is at about 2.4 trillion cubic feet. Working gas stocks remain 37.8 percent above the 5-year average and about 23 percent above last year's level. Why do natural gas prices remain at record levels if our storage rates are strong and does the 5 year average storage number reflect the increase in demand we have experienced in gas over the last 5 years? What is the level of protection that this level of storage provides compared to other years?

Answer. Natural gas prices spot prices have dropped significantly as extremely mild weather in January and early February led to an unusually low draw on gas from storage. For example, Henry Hub spot prices, which exceeded $15 per million Btu in mid-December, declined to below $7.00 per million Btu on Monday, February 27. Projected winter heating costs, while still higher than those experienced last winter, are significantly below our expectations at the beginning of October.

While natural gas prices have fallen sharply, they remain far above levels typical of the 1990s. One factor working to prevent a return to much lower prices is the difficulty of increasing supply in North America, notwithstanding very high levels of drilling activity. Competition between natural gas and oil products is another factor that limits opportunities for a sharp fall in natural gas prices. Lastly, although natural gas in storage has exceeded the 5-year average throughout the current heating season, withdrawals since the start of the heating season on November 1 have been limited. There has been an apparent reluctance by industry to draw down stocks heavily owing to the economic incentives to retain gas in storage posed by the unusually large premium of futures contract prices over the Henry Hub spot price, the concerns about supply availability throughout the winter while hurricane-related production shut-ins continue, and the uncertain demand impacts of winter weather. Absent significant withdrawals from storage, the presence of large volumes in storage does not have a direct effect on market prices.

The level of working gas stocks in underground storage on November 1 (the start of the heating season) in 2001-2005 exceeded 3,100 billion cubic feet (Bcf), after averaging 2,948 Bcf during the period 1995-2000. This additional gas in storage is equivalent to an average of more than 1 billion cubic feet per day of additional supplies throughout the 5-month heating season.

TRANSPORTATION

Question 1. The AEO 2006 forecast projects that most of the growth in demand for transportation energy occurs in light duty vehicles (57 percent of total growth). Can you estimate what amount of the projected growth in demand for fuel for light duty transportation vehicles will be met by ethanol or other renewable fuels?

Answer. In the United States, transportation ethanol is currently consumed as a blending component in reformulated gasoline (between 5.7 percent and 10 percent ethanol content), as gasohol (up to 10 percent ethanol blended with conventional gasoline), or as E85 (up to 85 percent ethanol and the remainder gasoline). Ethanol is used in the transportation sector almost exclusively as a blending component in gasoline (99.7 percent of total demand in 2004) and although total ethanol demand increases more than 350 percent over the projection period it continues to be used primarily as a blending component in gasoline (99.6 percent in 2030). Growth in light duty vehicle (cars, vans, sport utility vehicles, and pickups with a gross vehicle weight rating less than 8,500 pounds) energy demand increases 6.77 quadrillion Btu from 2004 to 2030, accounting for 57 percent of the total increase in transportation energy demand. Ethanol represents all of the projected increase in transportation renewable fuel use and increases by 0.72 quadrillion Btu from 2004 to 2030. Light duty vehicles account for 97 percent of total gasoline demand in the transportation sector and, assuming that all the projected consumption of ethanol was used by light duty vehicles, it would account for 11 percent of the total increase in light duty vehicle energy demand to 2030.

Question 2. In 2030 what proportion of U.S. CO_2 emissions will be produced by the transportation sector?

Answer. Between 2004 and 2030, the *Annual Energy Outlook 2006* reference case projects that the share of U.S. carbon dioxide emissions attributable to the transportation sector will grow from 32.9 percent to 33.7 percent. Carbon dioxide emissions from transportation grow from 1,945 million metric tons in 2004 to 2,734 million metric tons in 2030.

During the same period, U.S. total carbon dioxide emissions are projected to increase from 5,919 to 8,115 million metric tons.

COAL

Question 1. U.S. coal resources represent about a 250 year supply at current rates of consumption. The AEO 2006 forecast notes that “Coal remains the primary fuel for electricity generation and its share of generation (including end-use sector generation) is expected to increase from about 50 percent in 2004 to 57 percent in 2030.” The AEO 2006 report also notes that a “fast growing market for coal is expected in coal-to-liquids (CTL) plants.” The AEO 2006 High Price Case projects that Coal to Liquids plants could consume 420 million short tons of coal in 2030. With the large growth in demand for steam coal and greater use of coal in coal to liquids applications, how long can we expect our coal reserves to last?

Answer. Based on the *Annual Energy Outlook 2006,* coal reserves are projected to last 150 years beyond 2005.

In the *AEO2006* reference case, cumulative coal consumption between 2004 and 2030 is expected to be 37 billion short tons. This consumption represents about 14 percent of the estimated recoverable coal reserves (268 billion short tons) as of January 1, 2004. If the projections for coal consumption in the *AEO2006* grow through 2030 and then remain at that level, currently identified coal reserves would last roughly 150 years.

In the high oil price scenario, coal consumption is projected to be higher than in the *AEO2006* reference case. If the high price scenario is assumed, our coal reserves will last 130 years, rather than 150 years.

There is uncertainty regarding the total amount of coal resource available and recoverable. The technologies available to extract coal in the future may allow a larger portion of the demonstrated reserve base to be recoverable.

Question 2. The AEO 2006 report estimates that "Between 2004 and 2030 . . . 174 gigawatts of new coal-fired generating capacity will be constructed, including 19 gigawatts at coal-to-liquids plants." How many new coal-fired generating stations is this if the average size of the plant is 600 Megawatts?

Answer. In the *AEO2006* reference case, 174 gigawatts of coal-fired plants are projected by 2030. Assuming a plant size of 600 Megawatts, this is about 290 plants. Of this 174 gigawatts, 19 gigawatts are coal-to-liquids plants. Again, if these were all 600 Megawatts, this would be about 32 plants.

Question 3. The AEO 2006 forecast projects CO_2 emissions from energy use will grow from 5.9 billion metric tons in 2004 to 8.1 billion metric tons in 2030 largely due to a continued reliance on coal for electricity generation and on petroleum fuels in the transportation sector. What proportion of the growth results from coal fired generation? Does the AEO 2006 projection take into consideration the use of carbon capture and sequestration technologies in new coal fired generation?

Answer. In the *AEO2006* reference case, carbon dioxide emissions from coal-fired power plants are projected to increase by 1,031 million metric tons between 2004 and 2030, representing 48 percent of the increase in total carbon dioxide emissions of 2,147 million metric tons. The projections for increased carbon dioxide emissions from coal-fired power plants include emissions from plants in both the electric power and industrial sectors. In the industrial sector, electricity generation at coal-to liquids plants is projected to produce 150 million metric tons of carbon dioxide emissions by 2030.

The *AEO2006* model forecast includes the representation of carbon capture and sequestration technology for advanced coal and natural gas generating plants. However, in the reference case these technologies are not projected to be utilized.

NUCLEAR

Question 1. In your testimony there is a forecast that 6 gigawatts of electricity from new constructed nuclear plants will come online thanks to the Energy Policy Act of 2005. The Annual Energy Outlook for 2006 also highlights that carbon dioxide emissions from energy use are projected to increase from 5.9 billion metric tons in 2004 to 8.1 billion metric tons in 2030, an average annual increase of 1.2 percent. If the 6 forecasted nuclear plants are not brought online, how does this affect the amount of carbon dioxide emissions?

Answer. The 6 gigawatts of new nuclear capacity are expected to generate approximately 47 billion kilowatt-hours of electricity in 2030. If that generation were to instead come from coal plants, an additional 42 million metric tons of CO_2 would be emitted, an increase of 1.3 percent in power sector CO_2 emissions and 0.5 percent in total energy-related CO_2 emissions.

ECONOMY

Question 1. How have higher energy prices affected the Gross Domestic Product (GDP) and what might we expect to happen to our economy over the next 20 years if the trend of energy price increases continues?

Answer. Over the past two years as the price of oil has gone from $30 per barrel at the end of 2003 to $60 at the end of 2005, GDP may have been affected negatively by approximately 1 percentage point below what $30 oil would have yielded. The *Annual Energy Outlook* (*AEO2006*) provides a high oil price scenario which can provide some insights into the macroeconomic impacts to be expected over the next 20 years. In this scenario, real GDP is approximately 1.0% lower in the 2010 to 2015 time frame relative to the reference case. However, the impacts of higher energy prices are not uniform. Some energy-intensive industries, such as chemicals, may be more vulnerable to the adverse impacts of rising energy prices. As the economy adjusts to higher prices after 2015, the difference in GDP between the two cases declines.

LOSSES IN REAL GDP WITH THE AEO HIGH PRICE CASE

	Loss in 2000 Dollars	Percent Loss
2007	$22 billion	0.2 percent
2010	$108 billion	0.8 percent
2015	$129 billion	0.9 percent
2025	$23 billion	0.1 percent

Responses to Questions From Senator Craig

Question 1. What percentage of energy will be emission-free (i.e., no carbon emissions—e.g., nuclear, hydroelectric, wind, geothermal, solar, etc.) in EIA's current baseline, and what are the percentages of each emission-free source. How do these assumptions change when each of the two more optimistic alternatives for lower-priced nuclear energy are assumed?

Answer. Emission-free sources currently represent 14 percent of total energy consumption, and ETA's reference case forecast projects that share to remain stable throughout 2030. In the two cases with more optimistic costs for new nuclear power, the emission-free share in 2030 increases to 15 percent and 17 percent, respectively, for the Advanced Nuclear case and Nuclear Vendor case. Nuclear power has the largest share of the emission-free sources, followed by biomass and hydro.

PERCENT OF TOTAL ENERGY CONSUMPTION FROM SPECIFIC EMISSION-FREE SOURCES, 2030

	AEO Reference case	Advanced Nuclear case	Nuclear Vendor case
Nuclear	6.8%	8.4%	10.9%
Hydro	2.3%	2.3%	2.2%
Geothermal	1.1%	1.1%	0.9%
Municipal Solid Waste	0.3%	0.3%	0.3%
Biomass/Wood	2.5%	2.5%	2.4%
Wind	0.5%	0.5%	0.5%

Alternatively, if only electricity generation in the power sector is considered, emission-free sources currently represent 29 percent of total generation, and EIA's reference case forecast projects that share to drop to 24 percent by 2030. In the two cases with more optimistic costs for new nuclear power, the emission-free share in 2030 increases to 28 percent and 33 percent, respectively, for the Advanced Nuclear case and the Nuclear Vendor case. Again, nuclear power has the largest share of the emission-free sources, followed by hydro. Biomass is not as much of a contributor in this case, as it is used primarily in industrial applications.

PERCENT OF TOTAL ELECTRICITY GENERATION FROM SPECIFIC EMISSION-FREE SOURCES, 2030

	AEO Reference case	Advanced Nuclear case	Nuclear Vendor case
Nuclear	14.7%	18.3%	23.8%
Hydro	5.1%	5.1%	5.1%
Geothermal	0.9%	0.9%	0.8%
Municipal Solid Waste	0.5%	0.5%	0.5%
Biomass/Wood	1.7%	1.6%	1.5%
Wind	1.1%	1.1%	1.1%

Responses to Questions From Senator Thomas

Question 1. In 2005, you did not include any coal to liquid numbers in your projections. I noted that in this year's outlook, you are projecting that by 2030, over 10% of future coal production will be used to generate liquid from coal. What caused you to make this adjustment in your calculations?

Answer. In the *Annual Energy Outlook 2005* (*AEO2005*) reference case projections, the production of coal liquids was not competitive because the world oil price was approximately $21 per barrel less than the *Annual Energy Outlook 2006* (*AEO2006*) reference case projections. In the *AEO2005* High B case, crude oil prices were roughly comparable to the crude oil prices in the *AEO2006* reference case. In 2025, CTL production was projected to be about 980,000 barrels per day by in the *AEO2005* High B case, which is more than the projected 580,000 barrels per day in the *AEO2006* reference case. The lower estimate in the *AEO2006* reference case, compared to the *AEO2005* High B case, reflects a reassessment, raising the capital costs associated with the coal-to-liquids production process.

Question 2. You stated in your written testimony that under your "likely energy future" analysis, energy consumption is expected to increase more rapidly than domestic energy supply through 2030. This will make us more energy dependent, not less. That's a troubling projection.

As a nation, what do we do to change that projection? Under any of the scenarios you use in your Outlook, is there any way for the United States to achieve energy independence?

Answer. There is little that the Nation can do practically to achieve complete energy independence in the foreseeable future short of drastic social and structural changes. There are no scenarios completed as part of the AEO that achieve total energy independence.

In the *AEO2006* reference case, net imports are expected to constitute 33 percent of total U.S. energy consumption in 2030, up from 29 percent in 2004. hi the *AEO2006* high price case, with almost 70 percent-higher prices by 2030, net imports are projected to still account for 26 percent of U.S. energy consumption in 2030.

While supply, conversion, and demand technologies available today can decrease U.S. dependence on energy imports, a number of factors are substantial obstacles to complete oil independence. On the supply side, many technology options are expensive compared to imports even at current prices, the investments for the construction of adequate capacity require long lead times and huge investments, and the environmental and water consequences of certain supply options can be significant. On the demand side, a growing number of drivers and continued economic prosperity contribute to an expected increase in vehicle-miles traveled, while many consumers continue to favor vehicles that apply most advances in technology to improved performance rather than fuel efficiency.

Question 3. You mention that by 2030, nearly 59 percent of coal production will originate from the western United States. You also warn that a stable transportation system will be needed to achieve that figure.

I agree and believe our energy transportation system is inadequate to meet future demands. Whether you are talking railroads, pipelines or electric transmission lines, there are some serious weaknesses. Do you have any concerns about the current condition of our system?

Answer. The increase in coal production projected in the *AEO2006* could potentially cause short-term bottlenecks and would require additional capacity from transportation infrastructure, in particular the railroads. Railroads are a capital-intensive industry requiring investment in infrastructure to keep up with normal wear-and-tear on railcars, tracks, etc. The projected increase in coal demand in the *AEO2006* will necessitate investment in capacity that extends beyond normal maintenance. While predicting the exact magnitude of railroad investments needed is beyond the scope of the *AEO2006* forecast, the projected large increases in coal volume indicate that some portions of the railroad network may be more vulnerable to congestion than others.

Possible areas of congestion include the Joint Line, a section of railroad required to move coal out of the Wyoming Powder River Basin. An increase of 275 million short tons is projected for the Wyoming Powder River Basin between 2004 and 2030. Of that quantity, about 100 million tons is projected to be shipped to the Midwest. The *AEO2006* also projects over 100 million additional tons from the Interior region for generation plants in Kentucky and Tennessee. Some changes in transportation patterns for coal produced in Northern Appalachia are also projected.

Although the magnitude of increases in coal shipment between 2004 and 2030 is large, the total projected increase is spread over 26 years. For instance, the largest single-year increase for Wyoming Powder River Basin coal is projected to be an incremental 27 million tons.

The coal-to-liquids facilities projected in the *AEO2006* are assumed to be built near existing refining capacity. Therefore, new pipeline capacity is not assumed. Many of the coal-fired generation plants are projected to be built in regions serving neighboring areas and may require the construction or expansion of transmission capacity.

Question 4. In your testimony you point out that energy consumption per capita fell in the 1970s in response to high energy prices and weak economic demand. Which had the greatest impact on consumption: high prices or a weak economy?

Answer. The statement in the testimony referred to a period from the late 1970s through the early-to-mid 1980s, when significant energy price and economic disruptions both affected energy use. Despite the first oil price shock in 1973/1974 and the subsequent 1974/1975 recession, energy use per capita rebounded in the second half of the decade to achieve its all-time high, about 360 million Btu per capita, in 1978 and 1979. After the 1979/1980 price shock, per-capita energy use fell to 332 million Btu in 1981, and then fell further, to 316 million in 1982 and 312 million in 1983, the time of the country's last relatively severe recession. How much of this additional 20 million Btu per capita drop was the continuing effect of high energy prices and how much was due to overall economic slowdown is difficult to say. However, in the next three years, when the U.S. emerged from the recession but energy prices were still relatively high, energy use rebounded only slightly, to the 320-325 million Btu per capita range.

It was only after the oil price collapse of 1986 that energy use once again moved ahead significantly, to 338.1 million Btu per capita in 1988. However, it should be noted that despite the relatively low (in real terms) energy prices that prevailed from the mid-1980s to the beginning of the 21st century, energy use per capita never again reached the level of the late 1970's. It reached as high as about 350 million Btu in the year 2000, before the next round of energy price increases began and per capita use fell again, to about 338 million Btu in 2003.

Responses to Questions From Senator Talent

NATURAL GAS PRODUCTION

Question 1. The graph at Figure 10 seems to show that domestic production of natural gas ceased to track consumption sometime around 1987 and is today about 15 percent less than consumption. You project that this rift will grow to about 21% by 2030. Can you tell me what initially caused this shortfall in domestic production and what has prevented us from closing that gap?

How much of a role do governmental restrictions on exploring for natural gas play in this continuing domestic production shortfall? Is the price of imported natural gas or LNG a critical factor (i.e., is it a matter of imports being cheaper or a lack of domestic supply)?

Answer. Imported natural gas and liquefied natural gas (LNG) have been priced competitively with domestic supplies, which has promoted growth in the volume of net imports. Larger volumes of net imports to the United States, however, have not prevented growth in domestic production. Natural gas volumes from domestic and foreign sources both have expanded from the 1986 level, as is shown in Figure 10.

The United States has been a net importer of natural gas since 1958, with the bulk of the volumes coming from Canada. After peaking at 1,198 billion cubic feet (Bcf) in 1979, net imports averaged only 843 Bcf in 1980-1986. However, regulatory initiatives during the mid-1980s promoted a more market-based system for trade between the two countries. In 1988 the creation of the U.S.-Canadian Free Trade Agreement prohibited most import or export restrictions on energy products.

The Energy Information Administration (EIA) has not recently assessed the impact of Government regulations or legislation on domestic production. However, there are estimates for the amount of natural gas resources subject to Governmental restrictions. According to the Minerals Management Service, 86 trillion cubic feet of natural gas is located in offshore areas under Federal leasing moratoria in the Atlantic and Pacific oceans, the Eastern Gulf of Mexico, and the North Aleutian Basin. The United States Geological Survey (USGS) estimates that 9 trillion cubic feet of natural gas resources are located in the Arctic National Wildlife Refuge (ANWR), which is also under a Federal leasing moratorium. Another 5 trillion cubic feet of natural gas, according to the USGS, is located in state waters where oil and gas drilling is prohibited by statute or administrative decree. A study conducted for EIA by a private consulting company estimates that 21 trillion cubic feet of natural gas resources are officially inaccessible in lower-48 onshore areas where leasing and/or surface occupancy are prohibited by Federal statutes or administrative decrees, and an additional 101 trillion cubic feet of lower-48 onshore natural gas resources are de facto inaccessible due to the prohibitive effect of compliance with various environmental and pipeline regulations.

EIA estimates that as of January 1, 2004, there were 1,273 trillion cubic feet of technically recoverable natural gas resources in the lower-48 states, including proved reserves but excluding volumes thought to be located in areas that are officially inaccessible.

CLIMATE CHANGE—IMPACT ON COAL

Question 2. I am looking at Figure 14, which shows U.S. carbon dioxide emissions by sector and fuel. I want to focus on the portion showing emissions by fuel source, the bars on the right. If I understand this graph correctly and assuming we were to try and cut overall CO_2 emissions focusing solely on coal, it appears we would have to cut our emissions from coal, meaning our use of coal, roughly in half in order to get overall emissions down to approximately current levels. Is that correct? And we'd have to virtually eliminate the use of coal, using today's technology, to get back to 1990 emissions levels. Assuming that's correct, what would be the economic impact of eliminating coal as a fuel source? What would we replace it with?

Answer. Based on the *AEO2006* reference case, and focusing solely on emissions from coal-fired plants, U.S. coal consumption in 2030 would have to be reduced by 68 percent to reduce carbon dioxide emissions back to the 2004 level of 5.9 billion metric tons, and by 97 percent to return emissions to the 1990 level of 5.0 billion metric tons.

While carbon reduction forecast scenarios were not modeled for the *AEO2006*, a past report completed by EIA for Senators Inhofe, McCain and Lieberman in June 2003 (analysis of S. 139, the Climate Stewardship Act of 2003) included several restricted greenhouse gas emission scenarios. The primary case in this report, the S. 139 case, projected a reduction in energy-related carbon dioxide emissions to 5.4 billion tons in 2025. In this scenario, substantial reductions in carbon dioxide emissions in the electric power sector were achieved through a switch from coal to natural gas, nuclear and renewable fuels. In addition, some advanced coal-and natural gas-fired generating capacity equipped with carbon capture and sequestration equipment was projected to be built. U.S. coal production in 2025 was projected to be 72 percent below the 2004 level and 69 percent below the 1990 level in this case.

ENERGY EFFICIENCY

Question 3. Looking at Figure 6, what effect has recent energy prices had on the ratio of energy use per capita? How about on energy use per dollar of gross domestic product? Doesn't this indicate that we as a nation have become more efficient in our energy use?.

Answer. The figure below* shows the ratios you ask about for the last three years (indexed to 2002, the last year before energy prices began to rise rapidly). In 2005, energy use per capita declined approximately 2 percent below its level during the 2002 through 2004 period.

One can think about how much energy we use per capita by observing two trends: what is the intensity of energy use in the production of output (the energy to GDP ratio) and how much GDP are we producing per capita (the GDP per capita ratio). During this period, the average refiner acquisition price for crude oil rose by over 100 percent. The higher energy prices caused energy use per GDP to decline at a significantly higher rate (3.1 percent per year) than in the 1990s (1.7 percent), in part due to changes in how energy is used (efficiency) and in part because some energy-intensive industries, such as chemicals, experienced lower growth than might otherwise have occurred (structural change). At the same time, the aggregate economy still grew on a per capita basis. Productivity remained high in spite of the high energy prices and per capita GDP grew by 2.5 percent per year, which acts to increase energy demand. Weather factors affecting energy use for heating and air conditioning also influenced energy consumption trends since 2002. On balance, energy consumption per capita declined by an average of 0.6 percent per year over the last three years.

RESPONSES TO QUESTIONS FROM SENATOR AKAKA

Question 1. Mr. Caruso, last year you testified before this committee that ultimately gas hydrates could be a large supplier of natural gas. At the same time, you expressed some pessimism regarding the development of the necessary technology. Along with my colleague, Senator Murkowski, I believe that gas hydrates are a potentially invaluable resource. Did you include gas hydrate reserves in your calculations regarding domestic supplies of natural gas?

Answer. Natural gas hydrates may become an invaluable resource in our future. Natural gas hydrates are not included in the domestic supplies of natural gas in

*The figure has been retained in committee files.

the *AEO2006* projections because gas hydrate production is not considered technically and economically feasible prior to 2030. Arctic gas hydrates are not projected to be produced because there are ample, lower-cost conventional natural gas resources to serve the Alaska and MacKenzie gas pipelines well beyond the 2030 time frame of the *AEO2006*. Deep-water ocean gas hydrate deposits will not be produced until considerable technological progress is achieved.

Question 2. According to the Annual Energy Outlook, there will be a growth in the use of coal for electricity production. What impact do you think this trend will have on the cost of electricity in the state of Hawaii, where virtually all of the electricity comes from oil-fired plants? If so, do you foresee that the high cost of shipping coal to Hawaii might off-set any savings?

Answer. As indicated, most of Hawaii's electricity generation comes from petroleum-fired power plants. These plants accounted for roughly 80 percent of Hawaii's generation in 2005. Hawaii's two coal-fired power plants, AES Hawaii and Puunene Factory, accounted for less than 15 percent of Hawaii's electricity supply in 2005. Unless new coal plants are built in Hawaii to meet demand growth or replace existing petroleum-fired plants; we do not believe that coal will have an impact on the cost of electricity generation in Hawaii.

However, it may be possible for Hawaii to increase its reliance on coal. Other countries, with shipping distances similar to Hawaii's, currently rely more heavily on coal. For example, Japan, which is located a similar distance from the large coal export ports in eastern Australia, relied on coal-fired plants for 28 percent of its total electricity supply in 2004, while oil-fired plants accounted for only 10 percent. This would suggest that shipping distance alone should not make increased coal use in Hawaii uneconomic.

Question 3. According to a recent BBC News article, Brazilian Flex-fuel cars, which run on a combination ethanol made from sugar cane and gasoline, took 53.6% of the Brazilian market in 2005. Would similar use of ethanol-fueled vehicles in the United States produce a sizable decline in oil imports?

Answer. The use of ethanol flexible-fueled vehicles such as those in Brazil would only produce a decline in oil imports if the ethanol supply in the U.S. was priced competitively with gasoline and an infrastructure existed to produce and distribute the ethanol.

There are currently about 5 million flexible-fuel vehicles in use the U.S. that are capable of running on either gasoline or E-85, and auto manufacturers sell about 800,000 new flexible-fuel-capable vehicles per year. While having these vehicles in the market place provides the potential to displace demand for gasoline, ultimately the cost and availability of E-85 will determine demand. Currently, there are approximately 500 fueling stations that offer E-85 out of about 180,000 stations nationwide. The majority of these stations are located in Minnesota and Illinois, where the price of E-85 is relatively competitive to gasoline. Until E-85 can be supplied across the country at competitive prices, the availability of flexible-fuel-capable vehicles will have little impact on oil imports.

RESPONSES TO QUESTIONS FROM SENATOR SALAZAR

REGARDING NATURAL GAS SUPPLIES AND PRICES

Question 1. Mr. Caruso, I'd like to take this opportunity to thank you for the good work your offices do that rarely gets brought up at these hearings—all the data collections and analysis that are used by the Congress and by businesses alike every day.

I see from your projections that the price of natural gas is expected to fall significantly over the course of this year. When I read your testimony, you say that these prices are expected to fall because of increased imports and increased drilling. Now, it isn't clear to me how increased drilling is going to cause natural gas prices to go down. When I look at your own EIA website, here is the trend I find: from 1999 to 2004, the United States of America increased the number of gas wells from about 300 thousand to a little more than 400 thousand. That is a huge increase: 33%. And yet after those huge increases in the number of wells, the overall production of natural gas production was up only 1%. So what does that mean? It means we are drilling faster and faster just to keep up. Are we going to bring another 100,000 wells online in the next 5 years? Possibly. But as the average production per domestic well keeps declining, as it has ever since 1971, it is hard to understand how more drilling will lower prices in the near term. Can you please comment on how these facts correlate to the dramatic decrease in price your Figure 1 shows for natural gas over the next couple of years?

Answer. Drilling has increased significantly the last few years with little increase in production, as indicated, primarily because the focus of the drilling has been in unconventional gas formations (i.e., tight gas, gas shales, and coalbed methane). Between 1999 and 2004, beginning-of-year unconventional natural gas reserves increased 69 percent (from 52.1 trillion cubic feet to 88.0 trillion cubic feet). Unconventional gas has a lower production-to-reserves ratio and a production profile that is flatter and longer than onshore conventional gas. So even though supply from traditional sources (conventional lower-48 and pipeline imports) is projected to continue to decline, production from unconventional sources is projected to slowly increase, putting downward pressure on prices in the mid-to long-term.

The short-term decline in the average wellhead price of natural gas is driven mostly by the projected significant increase in liquefied natural gas (LNG) imports. Net LNG imports are projected to increase more than 250 percent (or 0.96 trillion cubic feet) between 2005 and 2008, increasing from 0.59 trillion cubic feet in 2005 to 1.55 trillion cubic feet by 2008. During this same time period, U.S. natural gas consumption only increases 3 percent, or 0.66 trillion cubic feet.

REGARDING THE USE OF COAL

Question 2. I find your projections for the use of coal very interesting. Regardless of the scenario modeled, your projections show an increased reliance on coal and increased domestic production of coal here in America. In some cases this even includes coal to liquids, which interests me very much. Would you confirm that coal use in America is projected to increase regardless of what our energy future holds?

Answer. In general, in all cases in the *Annual Energy Outlook 2006,* we project that U.S. coal consumption will increase over our 2004 to 2030 forecast horizon. The estimated costs of reducing criteria pollutants that include sulfur dioxide, nitrogen oxides and mercury at coal-fired power plants are not expected to be prohibitive. However, in other analyses where we have examined the impacts of policies to reduce greenhouse gas emissions, we have projected much lower, and, in some cases, declining, coal production.

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