S. HRG. 108–511

ENERGY OUTLOOK 2004

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED EIGHTH CONGRESS

SECOND SESSION

TO REVIEW THE ENERGY INFORMATION ADMINISTRATION (EIA) ANNUAL ENERGY OUTLOOK 2004 REPORT REGARDING THE SUPPLY, DEMAND, AND PRICE PROJECTIONS FOR OIL, NATURAL GAS, NUCLEAR, COAL, AND RENEWABLE RESOURCES, FOCUSING ON OIL AND NATURAL GAS, AND TO CONSIDER COMMERCIAL AND MARKET PERSPECTIVES ON THE STATE OF OIL AND NATURAL GAS MARKETS

MARCH 4, 2004

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

U.S. GOVERNMENT PRINTING OFFICE

94–641 PDF WASHINGTON : 2004

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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C O N T E N T S

STATEMENTS

APPENDIX

ENERGY OUTLOOK 2004

THURSDAY, MARCH 4, 2004

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

The committee met, pursuant to notice, at 10:08 a.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. I apologize for being late. Good morning to my good friend from Wyoming.

We all had conflicts, so we want to say to the panelists we are going to do our best, if you help us. We cannot have extremely long statements, even from those of you who are very expert. We are going to have to read your statements with our staff and move along.

We are here to take stock of our energy situation and what our expectations are for the near and the long term. We hope this hearing will provide a little bit of an overview of the core issues, particularly on oil and natural gas, and that it will stimulate further hearings by the committee on more specific issues such as the future of liquified natural gas, LNG, and the status of international oil and natural gas development.

Oil and gas are the lifeblood of this economy. If they were not supposed to be, we have made them that for sure. They account for more than 60 percent of the energy consumed in this country.

On March 3, oil prices were $35.80 a barrel. Natural gas prices were, Senator Bingaman, $5.37 per Btu. These numbers reflect a continued trend of high prices. I am sure I am not alone in worrying about them hurting our economy as well as the economy of the globe which we participate in so dramatically.

It is clear that these prices are a reflection of an imbalance in supply and demand. Our national security and prosperity require that, if we can, we develop policies that encourage balance, balance in production, consumption, and price.

The energy bill, whether each and every one of us agree on all of it or not—I hope that we believe we can pass something before the year is out that will do a few things that are important. It will have some production incentives, permit streamlining, incentives for critical infrastructure like the Alaska natural gas pipeline, hydrogen initiatives, et cetera.

Yesterday there were a number of reports stressing the need to pass the bill after debate in the Senate, however that is. The distinguished minority leader indicated that there were sufficient votes, but I think the missing question in his statement was how many amendments will there be before that event occurs. We will get with him and ask him what that means. Maybe he can get with Senator Bingaman and ask Senator Bingaman what that means. I do not want to ask you here because that is not fair.

[Laughter.]

But obviously, sooner or later, we have got to know whether it is 5, 10, or 30. Maybe we will find a way to let anybody decide how many they want and figure out that the rules of the Senate will still let us get a bill.

I am worried, Senators and anybody else, that people are not going to wait around too much longer for this bill. They are going to start picking the good pieces. One of the great pieces in it is wind. Clearly the pressure is on because all wind production stopped. New projects I should say, and so the pressure is on to ask the committee to pass a 1-year extension or the like, Senator Bingaman. I do not know if you have heard that, but that is the latest. Take it out of the bill, pass a 1-year extension. I think as soon as that happens, the question is how far does it go. What happens to Alaska? What happens to the other provisions?

Now, having said that, I am going to move quickly now to Senator Bingaman and any other Senators. Senator Bingaman is welcome to have an opening statement. If the rest of you could do without and go right to questions, I would appreciate it. If not, we will go to——

Senator WYDEN. Mr. Chairman?

The CHAIRMAN. Yes.

Senator WYDEN. Just your thoughtfulness is always so helpful because, like you, I have the Budget Committee. If I could just take no more than 5 minutes, even for an opener to outline——

The CHAIRMAN. Senator Bingaman, is that all right with you?

Senator BINGAMAN. Fine.

The CHAIRMAN. Proceed.

Senator WYDEN. No. I will wait my turn. I am fine now.

The CHAIRMAN. Senator Bingaman.

Senator WYDEN. Thank you, Mr. Chairman. I appreciate it.

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

Senator BINGAMAN. Mr. Chairman, I appreciate your having the hearing. I think this is a very useful hearing. I look forward to hearing the Administrator of EIA explain to us their view as to not only future supply but future price for these various energy sources that we depend so much on. I think it is absolutely crucial to our economy that we have an adequate supply at a reasonable price. Obviously, we need all the wisdom we can gain from the Administrator and the other witnesses on what we can expect. So thank you for having the hearing.

The CHAIRMAN. Senator Wyden, would you like to take your 5 minutes and we will understand your having to be absent. I am supposed to be there too, but I am not going for a while.

STATEMENT OF HON. RON WYDEN, U.S. SENATOR FROM OREGON

Senator WYDEN. Mr. Chairman, thank you. Again, you have always been so gracious and I really appreciate it.

Mr. Chairman and colleagues, we have never had gasoline prices this high at this time of year before. Now, the oil companies say that it is not their fault, but I have released evidence indicating that the companies have deliberately curtailed refining capacity and increased their refinery margins, actions that boost gasoline prices higher.

In 2001, I revealed internal oil company documents showing that major oil companies pursued efforts to curtail refinery capacity as a strategy for stifling competition and boosting their profits. One oil company document revealed efforts to prevent the restart of the Powerine refinery in southern California because they feared its restart would reduce gas prices and refinery profits by 2 to 3 cents per gallon.

Now Shell Oil has announced that it is permanently shutting down its 70,000 barrels per day Bakersfield, California refinery which is critical to the entire west coast gasoline market, including my home State. As Yogi Berra said, "It's deja vu all over again."

Now, Shell claimed that there was simply not enough crude oil supply to keep the refinery operating, but recent news article have reported that both Chevron, Texaco, and State of California officials estimate that there is at least a 20- to 25-year supply of crude oil remaining in the area where the Bakersfield refinery is located. What makes Shell's decision to close the Bakersfield refinery especially curious is that the company never even tried to find a buyer. The California Attorney General is investigating Shell's action for potential antitrust violations.

But Mr. Chairman and colleagues, for the life of me, I cannot figure out why the Federal Trade Commission will do absolutely nothing to even investigate the Bakersfield refinery closure because this goes right to the heart of making sure that gasoline prices are affordable on the west coast of the United States.

Mr. Chairman, I would ask unanimous consent that the letter that I sent to the Federal Trade Commission on February 18, 2004, asking the Federal Trade Commission to investigate the implications for the west coast gasoline market of the Bakersfield refinery closure, would be made a part of the record.

The CHAIRMAN. That will be done.

[The letter of Senator Wyden follows:]

U.S. SENATE,
Washington, DC, February 18, 2004.

Hon. TIMOTHY J. MURIS,
Chairman, Federal Trade Commission, Washington, DC.

DEAR CHAIRMAN MURIS: I am writing to request that the Federal Trade Commission (FTC) use its continuing authority to re-examine recent mergers in the gasoline industry in order to investigate Shell Oil's plans to close its 70,000 barrel-per-day Bakersfield, California refinery on October 1, 2004. I urge the FTC to use this authority to determine whether this refinery closure will cause further anticompetitive problems in West Coast gasoline markets and to take appropriate action avoid any such problems.

As you know, the FTC has allowed two major oil industry mergers and acquisitions to proceed that involved Shell Oil's Bakersfield refinery—the merger of Chevron and Texaco and Shell's acquisition of Pennzoil-Quaker State. Prior to the merger of Chevron and Texaco, the Bakersfield refinery was operated by Equilon Enterprises LLC, a joint venture between Shell and Texaco. However, Shell acquired full ownership of the Bakersfield refinery when Texaco was required by the FTC to sell its Equilon holdings as a condition of the Chevron Texaco merger in 2001. Subsequently, in 2002, the FTC allowed Shell to acquire Pennzoil-Quaker State.

Although Shell's announcement of its decision to close the Bakersfield refinery maintained "there was simply not enough crude supply to ensure the viability of the refinery in the long-term," recent news articles have reported that both Chevron Texaco and State of California officials estimate that the San Joaquin Valley where the Bakersfield refinery is located has a 20-25 year supply of crude oil remaining. In fact, *The Bakersfield Californian* reported on January 8, 2004, that Chevron Texaco plans on drilling more than 800 new wells in the San Joaquin Valley this year which is "300 more new wells than last year." The fact that Shell's former joint venture partner is increasing its drilling in the area calls into question Shell's claim that a lack of available oil supply is the reason for closing its Bakersfield refinery.

It is also curious that Shell appears to have made no attempt to sell the Bakersfield refinery before deciding it had to be closed. The attached Shell Bakersfield Refinery Closure FAQ's included the following question and answer put out by the company:

> "10. Instead of closing the refinery, has Shell considered selling it?
>
> Any new owner would face the same issues Shell is facing; there is simply a lack of crude supply to operate this refinery."

Shell's position seems at odds with the rest of the oil industry which typically points to a lack of refinery capacity, rather than availability of crude oil to refine, as a persistent problem. For example, according to the American Petroleum Institute, current refinery utilization rates exceed 91 percent and these high utilization rates leave little excess refining capacity to respond to supply problems or disruptions. Given the lack of spare refining capacity in the oil industry and the impacts this can have on supply and prices, it is interesting that Shell would shut down a major refinery without even attempting to find a buyer.

In 2001, I revealed internal oil company documents showing that major oil companies pursued efforts to curtail refinery capacity as a strategy for stifling competition and boosting their profits. These efforts included working to prevent the restart of the closed Powerine refinery in Southern California. One company document revealed that if the Powerine refinery was restarted, the additional gasoline supply on the market could bring down gas prices and refinery profits by two to three cents per gallon and called for a "full court press" to keep the refinery down. The Powerine refinery's capacity was 20,000 barrels per day. Because of the much larger capacity of the 70,000 barrels-per-day Bakersfield refinery, the FTC should investigate the impacts closure of the Bakersfield refinery could have on both gasoline supply and prices at the pump.

Finally, the FTC should also look into Shell's plans to close its Bakersfield refinery as part of a troubling trend of refinery closures that is further concentrating the oil industry. According to information compiled by the Senate Permanent Investigations Subcommittee, mergers in the oil industry over the last few years and the closing of refineries have dramatically increased the concentration in the oil refining industry. Under one commonly used test for concentration, 28 states would now be considered tight oligopolies. In fact, the number of states which have high levels of concentration doubled from 14 to 28 between 1994 and 2000. And since then, the FTC has allowed additional oil company mergers to occur. The closure of Shell's Bakersfield refinery, the 12th largest in California, would further contribute to this already troubling trend, with potential adverse impacts on competition, production and prices for consumers.

For these reasons, I am requesting that the FTC use its authority to re-examine recent oil mergers to investigate whether the planned closure of Shell's Bakersfield refinery will create further anticompetitive problems in West Coast gasoline markets, such as raising prices or restricting supply. I would also urge that you undertake this investigation expeditiously to ensure there is sufficient time to take appropriate action before the refinery closure takes place.

Thank you for your attention and I took forward to your response.

Sincerely,

RON WYDEN,
U.S. Senator.

Senator WYDEN. Mr. Chairman, the only other point that I wanted to make is the Consumer Federation of America has, I think, done some very good work to look at these questions of refinery margins. They have done an analysis saying that the refinery margins are taking three times as big a bite about of consumers' pockets, for example, as the actions of the OPEC cartel, which are continually highlighted by many in the oil industry. And I would ask unanimous consent that a Consumer Federation of America letter dated March 4, 2004 be made a part of the record as well.

The CHAIRMAN. That will be done.

[The letter from the Consumer Federation of America follows:]

CONSUMER FEDERATION OF AMERICA,
Washington, DC, March 4, 2004.

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

DEAR CHAIRMAN DOMENICI: It has come to my attention that the Senate Energy Committee is holding another hearing into the ongoing crisis in domestic energy markets without inviting a witness to present a consumer view. The failure of the Congress and the Bush Administration to look beyond the supply-side of the market and craft a balanced approach has frustrated energy policy in this country for the past four years.

The National Energy Policy Task Force headed up by Vice President Cheney, which framed the energy policy agenda, remains embroiled in a controversy over the excessive influence that producers and industry had in the deliberations. For the Senate to repeat the mistake of the task force-would be a grave mistake, The "supply-side only" approach will not solve the problem and attempting to shut out demand-side voices will only make it more difficult to reach a consensus.

The Consumer Federation of America has been the leading consumer group dealing with energy problems in the past two decades. Attached is an op-ed piece outlining the Weaknesses of energy policy that excludes the demand side of the equation.

Also attached is a report published five months ago, which demonstrates that approximately $30 billion of increased gasoline costs—about three quarters of the total increase of the past three years—are domestic in origin. Domestic refining and marketing operations of the oil companies are imposing record costs on consumers. Public opinion polls show that American consumers reject the argument that foreign producers are the sole cause of high energy prices and our research shows that they are right.

These facts must be taken into account if a genuine solution to the energy problem is to be found. I urge you to ensure that this perspective—the "other side of the story"—is presented to the Committee at the earliest possible moment.

Sincerely,

MARK N. COOPER,
Director of Research.

Senator WYDEN. The last point I would make, Mr. Chairman, I just think it sure looks like the oil companies are using higher oil prices as an excuse to increase their refinery margins and pad the bottom line. A prime example is Exxon Mobil which last year announced an all-time record profit of $4.4 billion, the highest profit by any company in history, and here again the Federal Government is sitting on its hands with respect to stopping oil companies from exploiting the tight supply market by padding refinery margins and profits.

So the chairman has been very gracious to give me a few minutes to outline these concerns. Like the chairman, I will be in and out through the course of the morning because of the Budget Committee, but I intend to come back and ask some questions with respect to these issues.

This Bakersfield closure does not smell right. It does not add up and it has great implications for the entire west coast market. In California they are paying over $2 per gallon. That is the case in

Hawaii as well. My State is not far behind at nearly $1.80 per gallon. I have to tell you, this Bakersfield closure smells and we are going to stay at it until we get to the bottom of it.

Mr. Chairman, I thank you very much for your thoughtfulness this morning.

The CHAIRMAN. Thank you very much, Senator.

How about on my side? Do either of you want to make some remarks?

Senator SMITH. Mr. Chairman, in the interest of time, I may include a statement in the record.

The CHAIRMAN. Whatever you would like, Senator.

Senator Thomas.

STATEMENT OF HON. CRAIG THOMAS, U.S. SENATOR FROM WYOMING

Senator THOMAS. I will be very brief also.

I certainly appreciate having this meeting. We have been reading the balance of gas policy, the annual outlook report here. Clearly, we have a problem and we need to talk about conservation. We need to talk about research. We need to talk about alternatives. We need to talk about domestic production. We have been trying to do that, so we need to make it more clear that we are in a situation where we have to make some moves.

Thank you, sir.

The CHAIRMAN. Thank you.

Can we proceed now? You got my admonition. We are going to start with panel one, Guy Caruso, Administrator of the EIA, Department of Energy. Would you start? And your statement will be made a part of the record right now, and you give us your testimony as quickly as you can. We will not ask questions unless the Senators need to. We will go to the other witnesses and then come back. Proceed, please.

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

Mr. CARUSO. Thank you, Mr. Chairman and members of the committee. The Energy Information Administration is pleased to be represented here at this hearing and to present our outlook.

As we end the winter of 2003-2004, market fundamentals are extremely tight in both the oil and gas markets. On a global basis, we are producing about 80 million barrels a day of oil in 2004, and the unused productive capacity is only about 2 million barrels a day and most of that is in Saudi Arabia. So we are operating a global oil industry with only about 2.5 percent of unused capacity which, of course, means there is little flexibility in the system.

Similarly in North American natural gas, we are stretched very thin, particularly on the production side, as has already been mentioned. These fundamentals of supply and demand have led to a very tightly balanced supply/demand situation. Therefore, the market is vulnerable to surprises. Any demand or supply changes or unexpected events such as industrial accidents, weather, all lead to spikes in prices.

The combination of rising world oil demand growth, fairly low inventories, and production restraint by OPEC has kept oil supplies tight globally and we expect prices to remain relatively high.

U.S. inventories are low both for crude oil and for major products. Gasoline, as was mentioned, is in very tight supply, and this is true as we look around our OECD partners in the EIA.

EIA expects the average price of West Texas Intermediate, the benchmark crude, to stay in the $29 to $35 per barrel range over the next 2 years in our short-term forecast. Of course, as was mentioned, the current price is almost $36, and we are in the process of preparing our March outlook and we will be looking again at our price projections. The gasoline market is extremely tight, and it is led by the fact that it is a very inflexible system that has to meet demands of a large number of different specifications, including the most recent MTBE bans in New York and Connecticut.

OPEC production decisions, of course, also affect the crude price and have been influencing price trends. In 47 out of the last 52 months, the OPEC benchmark price for its basket of crudes has been within or above their targeted range of $22 to $28 and, in the last several months, has been above $30. OPEC, on March 31, announced a further restraint on production with a quota cut that begins on April 1.

As this chart shows, the natural gas composite spot prices have also been very high, averaging $5.50 per 1,000 cubic feet last year. That is a 70 percent increase over 2002. And consumers are paying about $10 per 1,000 cubic feet which, of course, has added to the cost to the households across this country. We expect that price of roughly $5.50 per 1,000 cubic feet to be sustained over the next 2 years, given the supply/demand situation.

In the longer run, we do not think the $5 price is sustainable and we do see it coming down toward the end of this decade as alternative supplies in the form of Liquified Natural Gas (LNG) put some competitive pressure on that price, and prices may come down to below $4 per 1,000 cubic feet by 2010. But we will be, of course, watching that market very closely as we approach that period.

We then see prices rising after 2010 in our long-term outlook, shown in this chart, depending very much on the success rate in the drilling in this country and the ability to bring in the Alaskan gas and LNG at the cost that we now foresee.

So clearly we are in a situation in this country where our traditional sources of gas are declining and we will need to rely on nonconventional sources, coalbed methane, tight sands, and shale gas, as well as Alaskan gas in order to achieve the 31 tcf supply that we think we need by 2025.

My final chart, Mr. Chairman and members of the committee, is the oil outlook for the period through 2025, and we do expect oil prices to stay in real terms in that $25 to $27 per barrel range. But we know the volatility that has been witnessed in recent decades, and we certainly expect that volatility will continue. Therefore, we need to be prepared to deal with what I would label as an asymmetrical risk toward the higher end of our price forecast.

Therefore, Mr. Chairman, I will conclude by saying we are facing high and volatile oil and gas prices in the short run, and, although we expect some tempering of that in the long run, it will mean continued and increasing import dependence for both oil and natural gas.

Thank you once again for this opportunity.

[The prepared statement of Mr. Caruso follows:]

PREPARED STATEMENT OF GUY F. 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 outlook for energy markets in the United States and recent developments in world oil markets.

The Energy Information Administration (EIA) is the 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 Department of Energy, other government agencies, the U.S. Congress, and the public. We do not take positions on policy issues, but we do produce data and analysis reports that are meant to help policymakers determine energy policy. Because the Department of Energy Organization Act gives EIA an element of independence with respect to the analyses that we publish, our views are strictly those of EIA. They should not be construed as representing those of the Department of Energy or the Administration.

Each month, EIA updates its *Short-Term Energy Outlook* (*STEO*), which contains monthly projections through the next two calendar years, taking into account the latest developments in energy markets. Once each year, EIA updates its longer-term outlook in the *Annual Energy Outlook*, which currently provides annual projections for U.S. energy supply and demand through 2025. My testimony today is based on projections from the February 2004 *Short-Term Energy Outlook* and the *Annual Energy Outlook 2004* (*AEO2004*).

These projections are not meant to be exact predictions of the future but represent a likely energy future, given technological and demographic trends, current laws and regulations, and consumer behavior as derived from known data. EIA recognizes that projections of energy markets are highly uncertain, subject to many random events that cannot be foreseen, such as weather, political disruptions, strikes, etc. Many of these uncertainties are explored through the generation of alternative cases.

The projections are not statements of what will happen but of what might happen, given certain assumptions. Because EIA does not propose, advocate, or speculate on changes in laws and regulations, one of our key assumptions is that all current laws and regulations remain as enacted. For *AEO2004*, that means, for example, that provisions in the current House and Senate energy bills, such as an Alaska gas pipeline tax credit, are not included in this forecast.

OIL PRICES

A combination of rising world oil demand growth and restraint by the Organization of Petroleum Exporting Countries (OPEC) has kept oil supplies tight and oil prices relatively high. EIA expects the average price of the benchmark West Texas Intermediate (WTI) crude oil to remain in the $28-$30 range through 2005, as shown in Chart 1.* price projections are based on our February 2004 *STEO*. We are currently reevaluating these projections for our March *STEO*, and we are likely to revise these projections upward due to the continued tightness in the market.

This crude oil price projection from February would translate into an average regular gasoline price of about $1.57 per gallon in 2004. Last year, gasoline prices peaked twice in March and again in August. This year, the average retail price for regular gasoline is up 24 cents per gallon since December 29, 2003, with an increase of 3 cents per gallon last week alone. While the largest increase has been seen in California (up 51.4 cents per gallon over this period, with a jump of 8.0 cents per gallon last week), there have been significant increases across the country. While it is still too early to know with any certainty how high prices will go this year, many signs are pointing to a tight gasoline market this driving season.

A typical household has two personal vehicles, each typically is driven about 11,000 miles per year, with an average on-the-road efficiency of about 20 miles per gallon. Such a household would spend about $1,700 for gasoline in 2004—similar to last year's costs but about $200 above expenditures in 2002. Because there is a

*The charts have been retained in the committee files.

wide range of variation across households in the number of vehicles owned, vehicle efficiency, number of miles driven, and the local price of gasoline, the impacts of higher gasoline prices for specific households can vary widely from this average value.

ANNOUNCED CUTS IN OPEC QUOTAS

On February 10, 2004, OPEC (excluding Iraq) announced that it would cut its production quotas, trimming 1 million barrels per day from its current quota beginning April 1. In addition, OPEC asked its members for a strong commitment "to comply with the agreed production levels". Recently, OPEC production has been more than 1.5 million barrels per day above existing quota levels. If OPEC production were actually reduced to the new quota levels, OPEC production would fall by 2.5 million barrels per day—a decline of 10 percent. World oil prices increased by $2 per barrel in the first week following the OPEC announcement.

ETA's February *STEO*, developed prior to OPEC's February 10th announcement, projects that actual OPEC production will decline during the second quarter of 2004 by 1.5 million barrels per day from February levels. Under this projection, OPEC would still be producing 1 million barrels per day above the new April 1 quotas, a plausible outcome given recent experience. EIA believes that this production is consistent with WTI prices staying in the high $20s to low $30s in 2004.

There is always considerable uncertainty regarding OPEC's quota adherence and the size of any cutbacks that will actually be made. For example, OPEC announced on September 24 of last year that it would cut its quota by 900,000 barrels per day effective November 1, 2003. OPEC also emphasized the need for strict quota adherence, much as it did in its February 10, 2004, announcement. Despite these public statements, actual OPEC production rose, not fell, and OPEC production is higher now than it was during September. Even with this higher production level, WTI spot prices increased from an average of $28 per barrel in September to a current monthly average of nearly $35 per barrel, largely because of rising demand and low inventory levels.

OPEC has been successful during the past 5 years in adjusting production to keep prices from falling (Chart 2). As a result, the average price of a basket of OPEC oils has been within or above its stated target range of $22-$28 per barrel for 47 out of the past 52 months.

NATURAL GAS

Market factors are also keeping natural gas prices high. In 2003, the average natural gas spot price was about $5.51 per thousand cubic feet, about $2.30 per thousand cubic feet more than the 2002 average, for an increase of more than 70 percent. This increase was driven, in part, by the extraordinarily high level of storage refill requirements. We expect natural gas spot prices to retain most of that increase through at least 2005 as shown in Chart 3.

Residential natural gas prices, which respond to spot prices with a lag, are expected to show an average increase of about $2.10 per thousand cubic feet between 2002 and 2004. The average household having a gas hookup in the United States uses about 82 thousand cubic feet per year. The expected 2-year increase means that households will pay about $815 in 2004, roughly $170 more than in 2002.

WINTER HEATING COSTS

With a significant part of the heating season now past, the estimated winter 2003-2004 household heating bills, compared to last winter, are as follows:

- Natural gas-heated homes: up by 11 percent. Despite some decline in demand, residential prices this winter have reflected increased gas acquisition costs accumulated since the previous winter, as well as high near-term prices for spot natural gas.
- Heating oil users: down by 1 percent. High crude oil costs and strong heating oil prices in the Northeast have been keeping bills for oil-heated homes high, but probably a bit below last winter as overall demand this season is expected to be slightly below the level seen in the 2002-2003 winter.
- Propane-heated households: up by 7 percent. In this case, the average price increase is likely to offset the overall decline in demand.
- Homes with electric heat: up by about 2 percent. Retail electric rates are expected to be several percent higher this winter, due in part to higher fuel costs. This offsets a modest decline in demand due to weather comparisons.

Households have generally seen relatively high costs for heating fuels since 2000. EIA estimates that for the three winters between 2000 and 2003, a typical household (in areas where significant winter heating is required) probably paid an average of more than 40 percent more to heat the house than the average paid during the three prior heating seasons (Chart 4). It is worth noting that for homes heating with natural gas, heating oil, or propane, heating expenditures for this winter are shaping up to be more than 30 percent above the previous 6-year average.

COAL

Coal consumed by the electric power sector accounted for 92 percent of all coal consumed in the United States in 2002. For the first 9 months of 2003, coal consumed to generate electricity was 2.9 percent higher than for the same period in 2002. Coal and nuclear generation are typically used to meet base load (the minimum amount of electric power required at a steady rate) demand. Year-to-date nuclear generation was down 2.3 percent. Coal-fired generation, up 2 percent, took up the slack in base load demand and was also used, whenever possible, to replace expensive gas-fired generation. Strong projected growth in electricity demand in 2004 and 2005, 2.5 percent in both years, will be the impetus for continued electric sector coal consumption. Electric sector coal demand is expected to increase by 1 percent in 2004 and by an additional 3.4 percent in 2005.

Despite demand growth of 1.9 percent in 2003, we estimate that the full-year data for total U.S. coal production will show a decline of about 1.7 percent in 2003. Increases in imported coal and stock withdrawals (from producer and secondary sources) helped meet the demand growth in 2003. Coal production is expected to rise in 2004 and 2005 to meet the projected demand growth. Western region coal production is expected to continue its strong recent growth, while Appalachian and Interior production is expected to decline.

NATURAL GAS PRICES

In ETA's *AEO2004* reference case, average lower 48 wellhead gas prices are projected to decline from 2003 levels to $3.40 per thousand cubic feet (2002 dollars) in 2010, and then increase to $4.40 per thousand cubic feet in 2025 (Chart 5).

Wellhead gas prices rise over the long-term, because gas exploration and production costs are projected to increase as deeper and smaller gas reservoirs are brought into production to meet increasing demand. The rate at which gas exploration and production costs increase largely depends upon the future rate of technological progress. In the reference case, the future rate of technological progress has been set at the historic rate.

Future rates of technological progress, however, could be higher or lower than what has been observed historically, resulting in gas prices that are lower or higher, respectively, than what is projected in the reference case. The two other scenarios shown in this chart, the rapid and slow technology cases, illustrate the impact of technological progress on wellhead gas prices.

NATURAL GAS SUPPLY

Total natural gas supply, from both domestic and foreign sources, is projected to increase at an average annual rate of 1.4 percent per year between 2002 and 2025, reaching 31.3 trillion cubic feet in 2025 (Chart 6).

Traditional sources of supply, associated and non-associated conventional production in the onshore and offshore, will remain important, meeting 39 percent of U.S. supply requirements in 2025, compared to 56 percent in 2002. However, U.S. natural gas supplies will become increasingly dependent on unconventional production from tight sands formations, shale, and coalbed methane, natural gas from Alaska, and liquefied natural gas (LNG) imports.

Total non-associated unconventional natural gas production is projected to grow from 5.9 to 9.2 trillion cubic feet between 2002 and 2025. With completion of an Alaskan natural gas pipeline in 2018 (capacity of 3.9 billion cubic feet per day) and its expansion in 2023 (incremental capacity of 0.9 billion cubic feet per day), total Alaskan production is projected to increase from 0.4 trillion cubic feet in 2002 to 2.7 trillion cubic feet in 2025.

Nearly all of the increase in U.S. net imports is expected to come from LNG. *AEO2004* projects expansion at the four existing U.S. LNG terminals (Everett, Massachusetts; Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana) and, starting in 2007, the construction of additional facilities in the lower 48 States. EIA projects that between 9 and 12 new facilities will be constructed by

2025. Total net LNG imports are projected to increase from 0.2 trillion cubic feet in 2002 to 4.8 trillion cubic feet in 2025.

OIL PRICES

The historical record shows substantial variability in world oil prices, and there is similar uncertainty about future prices. The level of oil production by countries in OPEC is a key factor influencing the world oil price projections incorporated into *AEO2004*. Three price cases allow an assessment of alternative views on the course of future oil prices (Chart 7).

In the reference case, projected prices increase by an average rate of 0.6 percent per year from 2002, reaching $27 per barrel in 2025, in 2002 dollars. In nominal dollars, the reference case price is expected to reach almost $52 per barrel in 2025. In the low price case, prices are projected to decline from their high last year, reaching $16.86 per barrel this year and remaining at that level to 2025. The high price case projects a price rise of 1.7 percent per year from 2002 to 2025, with prices reaching about $35 per barrel in 2025. The projected leveling off in the high price case is due to the market penetration of alternative energy supplies that could become economically viable at that price.

OIL RESERVE RECALCULATIONS

During the past two months, several prominent oil and gas companies announced that they had made large downward recalculations of their oil reserves at a time when there has been increased attention to oil and gas reserve estimates. The Securities and Exchange Commission has been reviewing its reserve reporting requirements for more than a year. In addition, the Enron failure and the Sarbanes-Oxley Act of 2002 have brought about generally increased attention to and scrutiny of corporate financial reporting of all types. Finally, there has been some concern that these downward supply revisions came at a time when world oil demand has been growing rapidly and oil prices have been rising. EIA believes that while these oil and gas reserve write-downs may be noteworthy and may be one of the variables affecting current oil market dynamics, they are not large enough on a world scale to support the argument that world oil supplies are in short supply or to influence world oil prices significantly.

The reserve recalculations made by Shell and El Paso need to be put in perspective. These recalculations are notably large; however, companies revise reserve estimates from time to time. Revisions occur due to the inherent difficulty of precisely defining the concept of proved reserves and to the methodological difficulty of estimating proved reserves, because this estimation is subject to uncertainty even with improvements in technology.

In 2003, proved oil reserves on a global basis are continuing to increases, and there were no comparable dramatic revisions in any country's oil reserve estimates. Global proved reserves increased by 4 percent, or by 53 billion barrels, from the 1,213 billion barrels estimated in 2002, reflecting new discoveries in locations such as Africa. This upward revision dwarfs the comparatively small downward revisions made by Shell and El Paso. While these company revisions may represent a substantial portion of the companies' booked reserves, they account for only a small fraction of the world's proven oil reserve base of well over 1 trillion barrels. As a result, the reserve recalculations have not made much of an impact on world oil prices. Other factors, such as OPEC actions and tight world oil inventory levels, have been much more influential in influencing world oil price levels.

The downward revisions in oil reserves by some companies never questioned the amount of the petroleum present but merely reflected the timing of its development. Several billion barrels of oil equivalent were moved from the proved category to the probable category. Proved reserves refer to discovered oil or gas whose amount is known and is considered recoverable in both the technical and economic sense. Probable reserves are those which are believed to exist but are not developed for production or shown to exist through drilling. Although these revisions sent a shock to these companies' stocks and to a lesser extent selected other energy companies' stocks, it was only an exercise in adhering to the correct reporting conventions and not a harbinger of the world running out of oil.

COAL

Total U.S. coal production is projected to increase from 1,105 million short tons in 2002 to 1,543 million short tons in 2025 (Chart 8) to meet increasing demand for coal in the electricity sector. Continuing the historical trend, Western coal production is projected to continue increasing over the forecast horizon, while production from Eastern coal mines remains relatively constant. With virtually no growth in coal consumption projected over the *AEO2004* forecast horizon in the non-electricity sectors, the electricity sector share of total U.S. coal consumption is projected to increase from 92 percent in 2002 to 94 percent in 2025.

The CHAIRMAN. Thank you very much.

The second panel: Richard Sharples, senior vice president of Strategic Planning and Marketing, Anadarko Petroleum. Would you proceed?

STATEMENT OF RICHARD J. SHARPLES, SENIOR VICE PRESIDENT, STRATEGIC PLANNING AND MARKETING, ANADARKO PETROLEUM CORPORATION

Mr. SHARPLES. Yes, Mr. Chairman. Thank you very much for the opportunity to be here. We appreciate your leadership on energy challenges facing America, and I appreciate the opportunity to discuss particularly the EIA's forecast this morning.

For frame of reference, Anadarko is the Nation's seventh largest producer of natural gas and most active explorer. We operate across the United States on and off shore in Alaska and have a significant presence in the Rockies. One point I would like to make is our only business, Mr. Chairman, is to explore for, find, and produce energy. We are not in the downstream oil and gas business.

We commend EIA on its 2004 annual energy outlook report and we believe it does recognize many of the challenges facing oil and gas production and it realistically attempts to estimate our future potential.

Given our limited time, I would like to focus my remarks on natural gas where our experience suggests that EIA projections may be overly optimistic. As you are probably aware, we are still several months away from having a full picture of what our 2003 natural gas production actually was.

But early indications are that a production decrease, rather than the increase predicted by EIA, actually occurred. The initial reports from public companies, which account for about 70 percent of gas produced in the United States, actually reveal a decrease of 2 to 30 percent from 2002 production. Moving the starting point would obviously have a very significant impact on the expectations going forward.

Additionally we are observing continuously deteriorating well performance, as mature basins are increasingly exhausted and this will further constrain future production growth.

Based on our own analysis and experience in the field, we see three primary reasons why the EIA may err on the high side when it comes to supply forecasting. We believe the agency has overestimated the productivity for new wells, under-estimated the rate of decline of new wells, and under-estimated the unit costs. Additionally and significantly, the agency may have under-appreciated the significant time lags inherent in developing new resources. I address these points in much greater detail in my statement for the record.

Natural gas is clearly destined to play an increasingly important role in America's energy future. Unfortunately, this rising demand will exceed our ability to produce gas domestically, forcing America to rely on imports, including LNG, to bridge the gap and relieve upward pressure on price.

But the irony, Mr. Chairman, is that America is rich in natural gas resources. We do not have to become overly dependent on imports. We could and should produce much more here at home. When new areas are open for exploration, the industry will search for and likely will find new gas. The eastern Gulf of Mexico is an excellent success story where the MMS has expeditiously leased new acreage that will soon produce gas. We asked for access. You granted it in part and we acted on it.

Last year Anadarko discovered substantial quantities of gas in four successful exploratory wells in the eastern Gulf, and these wells are expected to begin producing by 2007. I would point out Mr. Koonce's company is a partner in one of those discoveries.

Unfortunately, many of the most promising natural gas prospects in this country, however, is still off limits to exploration because of moratoria or regulatory complexity. We commend Congress for resisting further restrictions. Even in the eastern gulf, most of the potentially 40 trillion cubic feet of natural gas is under moratoria, as are virtually the entire east and west coasts.

In fact, the National Petroleum Council, in their comprehensive 2003 report on balancing natural gas policy, estimates that as much as 200 trillion cubic feet of America's technically recoverable undiscovered natural gas lies under Federal lands where access is either denied or restrictions cause projects to be uneconomic. Working through this regulatory maze frequently raises the cost of doing business to the point where it becomes more cost effective to invest scarce capital abroad. In these cases delay is effectively the same as denial.

Let me be clear, though. We are not asking for permission to explore everywhere. For example, we do not want access to our precious protected wilderness areas or national parks. What we are asking for is more reasonable access to new resources, and we are committed to finding innovative ways to develop them. Environmentally responsible development is possible, especially when government and local groups and industry collaborate.

But I point out there are no quick fixes or easy answers when it comes to energy policy for America. There are, however, important steps we can take to relieve our growing dependence on imported energy and lower the price paid by the American consumers. Many of them are contained in the comprehensive energy legislation pending before Congress, which we see as a good and necessary start toward American energy independence. I will not go through the details, but we think they are very significant points and you brought most of them up earlier, Mr. Chairman.

Passing this energy legislation is an important first step to begin to address the issues and concerns raised by both EIA in their energy outlook and the National Petroleum Council in their 2000 report on balancing natural gas policy.

Thank you, Mr. Chairman. I would be glad to address questions at the appropriate time.

[The prepared statement of Mr. Sharples follows:]

PREPARED STATEMENT OF RICHARD J. SHARPLES, SENIOR VICE PRESIDENT, STRATEGIC PLANNING AND MARKETING, ANADARKO PETROLEUM CORPORATION

Mr. Chairman, I am Dick Sharples, Senior Vice President of Anadarko Petroleum Corporation. I thank you for your leadership on the energy challenges facing America and I appreciate the opportunity to participate in the Committee's consideration of the Energy Information Administration's (EIA) 2004 Forecast.

Anadarko is the nation's seventh largest producer of natural gas and most active explorer. We are an environmentally responsible producer onshore and offshore, including pioneer deepwater leases in the Eastern and Western Gulf of Mexico. We have a major presence in Alaska and in the Rockies; we also have significant international energy investments. Our only business, Mr. Chairman, is finding and producing the energy America needs to prosper and grow.

Anadarko commends the EIA on its Annual Energy Outlook 2004 report, which recognizes many of the challenges facing oil and gas production and realistically seeks to estimate future potential. We are generally comfortable with the Agency's outlook for domestic crude oil production.

We do, however, have some concerns in the key area of natural gas where our experience and data suggest the EIA projections—especially in regard to domestic production—may be overly optimistic. In its estimates for 2003, EIA assumptions include a modest increase in domestic natural gas production. We believe that there has actually been a production decrease. I hasten to emphasize that we still lack some of the key production data for 2003, but initial reports from public companies—which account for 70% of the gas produced in the United States—suggest a 2-3% decrease in natural gas production from 2002[1]. The difference between the EIA projection of a 1% increase and the potential 2-3% decrease we are sensing presents quite a divergent base upon which the forecast depends and could have important implications for the American economy and future energy policy.

Two of the fundamental factors bearing on our ability to respond to increasing demand for natural gas in this country are the facts that we are chasing an increasingly scarce resource and paying an increasingly high price to develop it. Over the decades we have found almost all the easy gas; we have developed the giant fields. Today, with demand increasing and with an environmental premium on natural gas, we must spend more to find less. We are seeing deteriorating well performance as mature basins are increasingly exhausted, further constraining future production growth. And—as a final irony—many of the most attractive prospects still out there are either under moratoria or encumbered by other access issues or regulations.

Based on our own analysis and experience in the field, we see three primary reasons why the EIA may have erred on the high side when it comes to natural gas supply. We believe the Agency may have overestimated productivity per new well, underestimated the rate of decline of new wells, and underestimated unit costs.

PRODUCTIVITY PER NEW WELL/BASIN EXHAUSTION

As noted above, we have been producing natural gas for generations in America, and we have found and produced from the most abundant and productive sources of gas. Today we are dealing with the concept of "basin exhaustion," which is a fancy way of saying that each incremental well we drill will bring on less natural gas than the previous well produced.

For example, as you can see in Exhibit 1*, the first 1,000 discoveries made on the Gulf of Mexico Continental Shelf added 40 billion barrels of oil equivalent (boe), most of it natural gas. But the next 1,000 discoveries are expected to generate just 6 billion boe because the basin is so mature. In other words, the next 1,000 wells are 85% less productive than the first 1,000.

The National Petroleum Council (NPC) published similar findings in its September 2003 report, "Balancing Natural Gas Policy." The NPC found that in 1990, wells drilled in the Lower 48 recovered 1.4 billion cubic feet of gas per connection; by 2001, the recovery rate had dropped to 1 billion—a 30% decrease over the decade.

The maturation, or exhaustion, of our basins leads to progressively less total gas and less daily deliverability from each new well. Exhibit 2 illustrates the deterioration in well productivity in terms of daily production per well. Well performance was at its best in 1996, with the average well achieving peak production of 1,300 Mcf/d. By 2002, the peak had steadily decreased to slightly over 800 Mcf/d, or nearly a 40% deterioration in productivity per well. Changes in well productivity must be accounted for when looking to future production potential.

[1] Based on surveys conducted by Jefferies and Co.
* The exhibits have been retained in committee files.

The EIA 2004 forecast discusses the challenges of maturing basins and declining well productivity, and assumes that reserve additions from onshore conventional natural gas wells, both exploratory and developmental, will add less than 1 billion cubic feet (bcf) per well to total reserves in each year of the forecast period. Much of the EIA's supply growth instead relies on unconventional reservoirs, many of which will have higher costs and higher decline rates. Although it is unclear what the AEO 2004 forecast assumes for costs and decline rates, Anadarko's experience in the field suggests that the EIA may still be underestimating decline rates and unit costs for new wells.

DECLINE RATES

Production decline rates for both old and new wells are fundamental factors in determining prospects for future growth because they determine how much new gas we must bring into production each year simply to stay even. For example, today we must bring a minimum of 13 BCF/day on stream just to replace the underlying decline. A decade ago the replacement figure was only 9 BCF/day.

Steeper decline rates of new wells increase the threshold for maintaining flat production and impair our ability to grow supply. We simply cannot use historical decline averages to estimate future supply. Over the last decade, decline rates for new wells have steepened continually and significantly. Today, production from the average well in the U.S. declines 55% in the first 12 months; a decade ago the decrease was only about 35%.

The type of wells we drill also has a profound impact on the decline rate. Tight sands formations, for example, have incredibly steep rates of decline. Exhibit 3 shows a production profile from Anadarko's tight gas production in Freestone County, Texas. These wells decline 75% from their peak in just two months! We would also note that much of the production increase posited by EIA relies on growth in tight gas. What we know about decline rates in these types of reservoirs suggests to us that it will be very difficult to grow tight gas production while we are on the treadmill of decline.

UNIT COSTS AND CORPORATE RETURNS

Not only does well productivity impact the challenges to supply growth, but it also makes rising unit costs a reality. If the well Anadarko drills today produces less gas than the well we drilled three years ago, then—on a unit of production basis, or a unit of reserves basis—our effective cost has increased. In addition, as we explore for new and increasingly scarce resources, we are forced to drill into deeper formations, move out further into deeper water, farther from existing infrastructure; all of these factors add significantly to unit costs.

Tight gas represents a good example of higher cost development. Tight reservoirs require stimulation and the use of fracturing technology. Developing the tight formations requires well spacing at 40 acres—compared to conventional 640 acre spacing. That means many more wells must be drilled. In our opinion, the wellhead prices indicated in EIA's forecast are therefore not likely to stimulate the volume of additional tight gas production to support their growth conclusions.

Exhibit 4 demonstrates that companies operating in North America have seen production costs increase by about 30% over the past five years while finding and development costs have increased by 175% during the same period.

Cost increases inevitably impact company returns. Even in a relatively high price environment, company returns have been eroding. Exhibit 5 below shows the decrease in returns on equity since 2000. We must have access to new areas that will deliver the returns needed to meet investor expectations.

COMPARISON TO NATIONAL PETROLEUM COUNCIL FINDINGS

Our sense that increasing domestic production of natural gas will be a great challenge is also consistent with many of the key findings of a recent, comprehensive study of gas markets conducted by the National Petroleum Council. In its September, 2003 report, "Balancing Natural Gas Policy" the NPC concluded that natural gas production from the Lower 48 states could grow by less than one half of one percent annually through 2020 if moderate changes in policy were enacted to streamline permitting processes and allow increased drilling and development activity in the Rocky Mountains. The 1% growth rate which serves as the basis for the EIA forecasts could only be achieved through a dramatic improvement in opening new areas to production and reducing regulatory delays.

FIRST STEPS: IMPROVED ACCESS AND THE ENERGY BILL

Natural gas is clearly destined to play an increasingly important role in America's energy future. Unfortunately, this rising demand will exceed our current ability to produce gas domestically, forcing America to rely on imports, including LNG, to bridge the gap and relieve upward pressure on price.

The irony is that America is rich in natural gas resources. We do not have to become overly dependent on imports. We could—and should—produce much more here at home.

When new areas are opened for exploration, we will find new gas. The Eastern Gulf of Mexico is an excellent success story, where the Minerals Management Service has expeditiously leased new acreage that will soon produce gas. We asked for access, you granted it in part, and we acted on it. Last year Anadarko discovered substantial quantities of gas in 4 successful exploratory wells in the Eastern Gulf, which we expect to begin producing in 2007. Unfortunately, many of the most promising natural gas prospects in this country are off-limits to exploration because of moratoria or regulatory complexity. We commend Congress for resisting further restrictions. Even in the Eastern Gulf most of the potentially 40 Tcf of natural gas is under moratorium, as are virtually the entire East and West Coasts.

In fact, the National Petroleum Council, in their 2003 report ("Balancing Natural Gas Policy"), estimates that as much as 200 Tcf of America's undiscovered natural gas lies under federal lands where access is tightly controlled or where restrictions cause projects to be uneconomic. Working through this regulatory maze frequently raises the cost of doing business to the point it becomes more cost-effective to invest scarce capital abroad. In these cases, delay is effectively the same as denial.

The same NPC study concluded that removing the Outer Continental Shelf moratoria and reducing the impact of conditions of approval on the Rocky Mountain areas by 10% per year for five years would add 3 billion cubic feet per day to domestic production in 2020 and would reduce the average price of natural gas by as much as $0.60 in nominal terms—which translates into a $300 billion savings to consumers over 20 years. That is compelling evidence of the extent to which we have constrained our ability to respond—here at home—to the energy challenge facing America.

Let me be clear, we are not asking for permission to explore everywhere. For example, we don't want access to protected wilderness areas or National Parks. What we are asking for is more reasonable access to new resources and we are committed to finding innovative ways to develop them. Environmentally responsible development is possible, especially when government, local groups, and industry collaborate.

There are no quick fixes or easy answers when it comes to an energy policy for America. There are, however, important steps we can take together to improve the situation and relieve our growing dependence on imported energy.

Many of them are contained in the comprehensive energy legislation pending before the Congress which we see as a good and necessary start toward greater American energy independence. Specifically, it—

- Streamlines permitting processes for exploration and development programs.
- Renews certain incentives like Section 29 tax credits, which have historically proven effective in increasing U.S. supply.
- Reduces barriers to gas pipeline permitting and construction.
- Imposes deadlines on appeals delaying offshore exploration and development.
- Authorizes the Alaska Natural Gas Pipeline which can bring 35 Tcf of currently stranded natural gas to the Lower 48 states.

Passing this energy legislation is an important first step to begin to address the issues and concerns raised by both the EIA in their Energy Outlook 2004 and the National Petroleum Council in their 2003 report on Balancing Natural Gas Policy.

Thank you again, Mr. Chairman, for the opportunity to address these important issues. I would be pleased to take your questions.

The CHAIRMAN. Are you finished, sir?

Mr. SHARPLES. Yes, sir.

The CHAIRMAN. We are going to now ask—Mr. Koonce, were you going to testify?

Mr. KOONCE. Yes, sir.

The CHAIRMAN. All right. You proceed and then we will go to Mr. Saunders.

STATEMENT OF PAUL KOONCE, CEO, DOMINION ENERGY, INC.

Mr. KOONCE. Yes. Thank you, Mr. Chairman. My name is Paul Koonce, and I am the chief executive officer of Dominion Energy, which is a subsidiary of Dominion Resources, the Nation's third largest utility in North America, with a market capitalization in excess of $20 billion. We own and operate electric generation facilities, electric transmission lines, natural gas facilities, and natural gas pipelines throughout the Midwest, Northeast, and Mid-Atlantic regions.

I also serve as second vice chairman of the Interstate Natural Gas Association of America and am here testifying today on their behalf. INGAA represents the interstate and interprovincial pipelines throughout North America and transports almost 90 percent of the natural gas consumed in America today through its 180,000 mile interstate pipeline network.

My message to you today is clear. Congress can and should play a critical role in promoting a stable energy marketplace. It can do so by empowering the appropriate agencies with clear and undeniable authority to authorize the build-out of our natural gas infrastructure. As we speak, there are specific examples where market forces are calling for it, the private sector is willing to invest, and the greater national good would be served. Yet, the need is not being met.

It is widely recognized that North America is experiencing a fundamental shift in the supply and demand for natural gas. Abundant natural gas resources exist in North America and worldwide and can supply the market at reasonable prices, but this desirable outcome can only come about with public policies that promote the development of resources and infrastructure needed to link national buyers and sellers across the Nation.

Increasingly local, State, and Federal permitting conflicts leave projects designed to build those important links in limbo. As a result, consumers and project developers cannot achieve the benefits so important to a healthy economy. For example, just this past winter, New York City prices soared to more than $40 per million Btu. This occurred while gas prices in neighboring States remained relatively stable as compared to Gulf Coast prices. The principal cause for this disparity has been inadequate pipeline infrastructure.

Let us be clear. Interstate pipelines and LNG terminals are important both to the interstate commerce and, in the case of LNG, foreign commerce. The Constitution clearly places the regulation of interstate and foreign commerce into the hands of Congress, and yet some individual States are developing arguments that usurp the authority of the Congress and the agencies that have been designated by Congress to improve such facilities, namely the FERC. When one State is given the power to veto multi-State projects, be it pipelines or LNG, then all States will eventually suffer the consequences.

This is one of the reasons Congress passed the Natural Gas Act of 1938. The NGA empowers the FERC to determine whether a proposed interstate pipeline is in the public interest and, if so, where and how it should be constructed.

The FERC has similar powers with respect to the siting of LNG terminals. Prior to the enactment of NGA, pipelines were approved on an individual State-by-State basis which led to a "beggar thy neighbor" dynamic. The result: inadequate pipeline infrastructure prevailed for everyone. This is why Congress took action in 1938 and why Congress needs to, once again, assert itself in the interest of the greater public good. Legislation pending here in Washington can move the Nation forward with predictable, positive results.

FERC's authority for siting natural gas pipelines must be respected by all Federal and State agencies. This has not been the case of late. For example, States have been delegated authority by the Congress to manage and implement the Coastal Zone Management Act, but some States are using the CZMA to veto interstate pipeline projects, to the detriment of entire regions. This is occurring despite the fact that FERC has already determined that these pipeline projects are in the public interest, that they meet the public convenience and necessity, which is a very high standard.

I urge you to clarify Federal authority and approve and site interstate pipelines once and for all. While I will not go into all the details here, several key provisions of S. 2095 would address these emerging impediments to interstate pipeline construction. This is why INGAA strongly supports passage of the comprehensive energy legislation.

I also want to talk about another important segment of the natural gas industry, that is, liquified natural gas. While INGAA is predominantly an interstate pipeline group, INGAA's members include owners of the four operational LNG terminals in the United States and they are also among those companies proposing new terminals at various sites.

The company I represent, Dominion, successfully reactivated the Cove Point terminal located on the Chesapeake Bay about 60 miles southeast of here. Fortunately, FERC and the U.S. Coast Guard have streamlined the approval of onshore and offshore LNG facilities, but the need to obtain final approvals from other Federal, State, and local agencies, also acting pursuant to Federal and State law, will likely be a significant factor affecting how quickly LNG developers can respond to the demands of the market. In other words, the conflicts that now exist for interstate pipeline approvals are likely to also manifest themselves in LNG siting.

We believe that codifying the Hackberry doctrine for LNG terminal construction and/or expansion, as proposed in S. 2095, is a positive first step. I would urge the Congress to continue monitoring the development of these terminals with an eye toward further clarification of FERC's authority to be the exclusive agency for determining whether these facilities should be built.

Mr. Chairman, the provisions of the energy legislation dealing with pipeline and LNG terminal construction are not those winning big headlines, but they represent areas where changes in the statutory framework for U.S. energy policy can help ensure that there is adequate pipeline and LNG import infrastructure to serve the energy needs of the Nation's economy.

Without an adequate natural gas delivery system, bottlenecks and higher cost for consumers and the economy will most certainly result.

Mr. Chairman, thank you for the time to be here this morning, and I look forward to answering any questions.

[The prepared statement of Mr. Koonce follows:]

PREPARED STATEMENT OF PAUL KOONCE, CEO, DOMINION ENERGY INC., ON BEHALF OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Good morning. My name is Paul Koonce and I am CEO of Dominion Energy Incorporated, a subsidiary of Dominion Resources. I am testifying on behalf of the Interstate Natural Gas Association of America (INGAA). INGAA represents the interstate and interprovincial natural gas pipeline industry in North America. INGAA's members transport over 90 percent of the natural gas consumed in the U.S., through a 180,000 mile pipeline network.

Dominion, headquartered in Richmond, VA, is one of the nation's largest producers of energy. Dominion's portfolio consists of nearly 24,000 megawatts of electric power transmitted over more than 6,000 miles of transmission lines, 6.3 trillion cubic feet equivalent of natural gas reserves, 7,900 miles of natural gas pipeline and the nation's largest natural gas storage system with more than 960 billion cubic feet of storage capacity. Dominion also serves 5 million electric and natural gas retail customers in nine states.

The North American pipeline network provides the indispensable link between natural gas production and the local distribution companies that serve retail consumers. Natural gas represents 25 percent of the primary energy consumed annually in the United States, a contribution second only to petroleum and exceeding that of coal. Consequently, the natural gas pipeline delivery network is a critical part of the nation's infrastructure.

It now is widely recognized that North America is experiencing a fundamental shift in the supply and demand equation for natural gas. INGAA agrees with the assessment that we are not running out of natural gas; rather we are running out of places where we are permitted to explore and produce it. Abundant natural gas resources exist in North America and worldwide and can supply the market with natural gas at reasonable prices, provided that public policies do not unreasonably limit resource and infrastructure development.

An important corollary to this answer is the important role of pipeline and storage infrastructure in ensuring that natural gas supply can satisfy market demand. Two examples, one from a producing region and another from a consuming region, illustrate this point:

The first example concerns how expanding the Kern River Gas Transmission Company interstate pipeline benefited both Wyoming producers and Nevada and California consumers. A year ago the prices received by Wyoming natural gas producers were sharply lower than those received by producers elsewhere in the West. The root cause of this disparity was that natural gas production in Wyoming exceeded the pipeline capacity available to export Wyoming gas to consuming markets. Wellhead prices in Wyoming fell to as low as 58 cents per million Btus (mmBtu) while wellhead prices in New Mexico—where pipeline capacity was much more prevalent—averaged about $1.60 per mmBtu.

This situation changed dramatically last spring when the Kern River expansion entered service. Kern River doubled the capacity of its pipeline from Wyoming to Nevada and California. As a result, producer prices in New Mexico and Wyoming are nearly identical now. Downstream consumers in Nevada and California have benefited as well from the increased competition between sources of gas supply. Other proposed new pipelines will provide additional outlets for Wyoming production. For example, El Paso Corporation is working on a new pipeline, called the Cheyenne Plains Pipeline, that will move Wyoming gas to markets in the Midwest. I would note that Rocky Mountain production is projected to continue increasing in the future. Therefore, unless pipeline infrastructure can keep pace, there is the prospect that gas supply again will outstrip the take away capacity for moving it to consuming markets.

The New York City market offers an example from the other end of the natural gas delivery chain. This winter, prices in New York City at times have exceeded $40 per mmBtu compared with average prices of $6 per mmBtu at the benchmark Henry Hub in Louisiana. The blame for this "basis blowout" has been laid squarely on the inadequacy of pipeline capacity for delivering gas into the New York City market. Pipeline capacity serving this market has remained the same for the past four years, despite steadily increasing demand. Because of this bottleneck, New York City residents and businesses pay much higher prices for natural gas than do consumers in other regions and even consumers in other cities in the Northeast. A recent study by the economic consultant Energy and Environmental Analysis concluded that consumers in the Northeast—and particularly in New York City—will continue having to pay unusually high natural gas prices until the bottleneck is relieved by the construction of new pipeline capacity entering the region.

This begs the question: Why hasn't the New York City bottleneck been relieved already? Numerous projects have been proposed, but few have been built. The already daunting task of constructing interstate pipeline infrastructure in developed areas has been made even more challenging by concerted local opposition that is focused increasingly on the state and local permitting process. The irony is that such dilatory tactics are contributing to the significantly higher natural gas prices being paid by consumers who, in many cases, live within the same jurisdictions that these permitting agencies represent.

The short-sighted focus of such opposition becomes apparent when one considers the consumer value that pipeline and storage capacity create by ensuring adequate energy supply and dampening price volatility. A perspective on this can be gained by comparing the cost of such infrastructure with the total cost of delivered natural gas. According to the Energy Information Administration (EIA), over the three-year span between 2000 and 2003, the cost of pipeline transmission and storage represented at most 15 percent of the average winter heating season price of natural gas paid by consumers in the United States. A bar graph illustrating EIA's analysis is appended to this testimony. Investing in adequate pipeline and storage infrastructure is a prudent insurance policy against the risks to consumers and the economy from the price shocks that can be caused by capacity constraints.

What solutions are there to the natural gas supply and infrastructure dilemma now facing us? As the Committee is no doubt aware, liquefied natural gas, or LNG, has captured the attention of both energy policymakers and the energy industry after years of being only a miniscule part of total U.S. gas supply. LNG clearly is part of the answer to the natural gas supply and demand question. It is not, however, a "silver bullet" that single-handedly will solve the problem.

While INGAA is predominantly a pipeline group. INGAA's members include the owners of the four operational LNG terminals in the United States. Dominion, in 2002 purchased, and last summer successfully reactivated, the Cove Point LNG terminal located on the Chesapeake Bay in Southern Maryland. Since that time we have received 38 ships and moved 105 Bcf of natural gas through the facility and into the mid-Atlantic market. In addition, INGAA's members are among the developers of proposed LNG terminals. Consequently, we have some perspective on the issues associated with operating and developing LNG import terminals

Federal regulators at the Federal Energy Regulatory Commission (FERC) and the U.S. Coast Guard have streamlined the approval of onshore and offshore LNG terminals. Still, just as with interstate pipeline projects, the need for final approvals issued by other federal, state and local agencies acting pursuant to federal and state law likely will be a significant factor affecting how quickly LNG developers can respond to demands of the market. Furthermore, if the hurdles are too high or if the approval process takes too long, LNG import facility development will be discouraged and project sponsors will deploy their capital elsewhere. On a related issue pertaining to LNG, I would like to commend the FERC for initiating a process to allow market participants to develop a consensus approach to handling the issues of gas quality and interchangeability. I am confidant that importers, pipelines, producers, and end-users will reach common ground on the issue.

There also must be adequate pipeline take away capacity for getting LNG supplies to consuming markets. Richard Grant, the President and CEO of Tractebel LNG North America, which operates an LNG receiving terminal in Everett, Massachusetts, stated at a conference recently that unless something is done, "[t]here will be 10 to 15 times more LNG capacity than (pipeline) takeaway capacity." This would be analogous to the situation in Wyoming that I addressed earlier; that is, too much natural gas supply trapped behind to little pipeline capacity. I can offer a specific project that clearly demonstrates the point: Dominion's recent announcement of plans to increase throughput capacity at Cove Point from 1 Bcf/day to 1.8 Bcf/day is dependent upon FERC approval of two associated pipelines to move that increased that capacity away from the terminal and into the market.

An important natural gas supply option in North America is Alaska natural gas. The members of the Committee are very familiar with the proposal to construct a pipeline that would deliver natural gas from Alaska to the Lower 48. Current estimates suggest a natural gas reserve of approximately 35 trillion cubic feet on the Alaskan North Slope, and possibly even more. In just the last several weeks, two different groups have proposed constructing an Alaskan Natural Gas Pipeline. It is encouraging that two competing sponsor groups have come forward. This healthy competition promises to result in a project that is more innovative and less costly than many previously thought.

These developments highlight the very real price that will be paid if the Congress fails to enact a comprehensive energy bill. Both the loan guarantees and the permitting process that would be authorized by H.R. 6 and S. 2095 are essential to making either of the competing proposals a reality. If we as a nation want natural gas from Alaska to begin flowing to the Lower 48 within the next decade, the legislation must pass soon.

While LNG and Alaskan natural gas are promising sources of gas supply, they alone are not sufficient answers to the nation's natural gas supply dilemma. If the United States wants adequate supplies of natural gas at reasonable prices, it must pursue all available supply that can be developed in an environmentally responsible manner. This means that we must expand supply from the Rocky Mountain region, the deepwater Gulf of Mexico, and Arctic Canada, as well as from Alaska and LNG. Failure to do so will cost consumers, the economy and the environment.

Let me now briefly review the public policies that affect natural gas pipeline construction and operation. Interstate pipelines are subject to economic regulation by FERC and safety regulation by the Department of Transportation Office of Pipeline Safety (OPS). Both agencies are widely recognized for their excellent work on natural gas pipeline siting and safety issues. FERC's leadership has emphasized prompt and thorough processing of pipeline construction applications and the agency's Office of Energy Projects has been very responsive to a wide variety of stakeholders in its review of pipeline applications. The OPS also deserves praise. The agency recently issued a wide-ranging, balanced final rule governing pipeline integrity, pursuant to the Pipeline Safety Improvement Act of 2002. The pipeline industry also appreciates the role played by the White House Task Force on Energy Project Streamlining. The White House Task Force took the lead in executing a Memorandum of Understanding to coordinate decision making among the various federal agencies whose authorizing statutes give them a jurisdictional stake in some aspect of the pipeline permitting process.

Yet, the pipeline industry has serious and growing concerns about the ability of federal, state and local regulators to erect impediments to efficient, timely pipeline construction. In particular, while the Natural Gas Act (NGA) provides FERC with the exclusive authority for determining whether proposed pipeline projects are in the public convenience and necessity, other agencies increasingly are using the jurisdictional hook provided by other laws to second guess the decisions made by FERC after a thorough review as part of the NGA certificate process.

The prime example of this has been some state agencies' use of delegated authority under the Coastal Zone Management Act to question pipeline routes that already have been reviewed and approved by FERC. This is now occurring in at least three instances. The problem has been compounded by the procedures followed by the National Oceanic and Atmospheric Administration (NOAA) of the Department of Commerce in reviewing appeals from state decisions finding a proposal to be inconsistent with its coastal zone management plan. In the one appeal that has been fully litigated at the administrative level, NOAA spent 18 months compiling its own record from scratch after the same issues had been thoroughly vetted as part of the FERC review process. This administrative delay created great uncertainty for the pipeline sponsor and penalized consumers by yet again postponing relief from the costs of the New York City pipeline bottleneck. These events also have cast a cloud over other pipeline projects in coastal states, including another proposal to serve the New York City area, as well as proposed LNG import projects that must run the same regulatory gauntlet.

In order to realize the widely recognized energy security and environmental benefits that can result from abundant and affordable natural gas supplies, the nation must take steps that facilitate the development of natural gas supply and infrastructure. Several important provisions in H.R. 6, the comprehensive energy bill, and now S. 2095, would remove impediments to building pipeline and LNG infrastructure. These provisions include the following:

- The bills would amend section 7 of the Natural Gas Act to authorize an appeal to the U.S. Court of Appeals for the D.C. Circuit if an action by a federal or state agency unreasonably delays or conditions the construction of a pipeline project authorized by FERC.
- The bills also would specify that the extensive record developed by FERC in its certificate proceeding must be used by other agencies in any administrative appeals concerning a project that has been reviewed by FERC.
- Reforming the Public Utility Holding Company Act will encourage the capital formation necessary for building energy infrastructure.
- As already mentioned, the Alaska Natural Gas Pipeline authorization is critical to constructing the infrastructure needed to bring this resource to consumers.

- The bills improve access to pipeline right-of-way corridors across federal lands and eliminate uncertainties surrounding the methodology used by the federal government in setting fees for using such rights-of-way.
- The bills would codify FERC's "Hackberry" decision to remove the open access requirement on new and expanded LNG terminals.

Congress may also need to further clarify federal supremacy in the approval and siting of pipeline and LNG terminals to be used in interstate and foreign commerce.

In sum, while these are not the provisions in the energy bill that garnered the headlines, they represent areas where changes in the statutory framework for U.S. energy policy can make a real contribution to ensuring that there is adequate pipeline and LNG import infrastructure to serve the energy needs of the nation's consumers and its economy.

Before concluding, I would like to highlight two additional issues for the Committee. The first deals with security and pipeline service surety. Because natural gas pipelines are a part of the nation's critical infrastructure, INGAA and its members have been working with numerous federal and state agencies in developing heightened security procedures. The Department of Homeland Security is now verifying these procedures through audits. A key part of this exercise is contingency planning for response and recovery should an incident occur. Along with the Department of Energy, we are modeling the effect and response to possible attacks/outages on key pipeline systems. We also are encouraging participation by the operators of other parts of the infrastructure so that we can appreciate better the interdependencies within of our national infrastructure and plan for how best to restore service in the event of an emergency.

The second issue is the implementation of the pipeline integrity rule that I mentioned previously. The mandate that natural gas systems in populated areas perform "integrity assessments" is one of the most important provisions in the Pipeline Safety Improvement Act of 2002. The new law establishes strict timeframes for baseline integrity assessments and reassessment intervals. Beginning this year and continuing throughout the decade, significant pipeline segments will be removed from service in order to perform assessments and any resulting repairs. This unprecedented integrity program will almost certainly affect natural gas deliverability and delivered natural gas prices. The effect could be compounded because, coincidentally, the integrity assessments will happen during what could be a protracted period of tight natural gas supplies. We urge Congress to pay close attention to the implementation of this rule, particularly if significant service disruptions begin occurring.

In closing, let me emphasize the importance of public policies that foster a positive environment for natural gas pipeline construction and investment. The interstate pipeline business model is not "build it and they will come". Rather, given the capital intensity of the pipeline business and its status as a regulated industry, pipelines are built only when a sufficient number of credit worthy shippers have committed to long-term contracts for firm service. Therefore, the overall health of the energy industry and policies that encourage shippers to make responsible choices in contracting for natural gas supply and pipeline capacity are important to maintaining sufficient natural gas infrastructure. The alternative is not desirable, because inadequate pipeline capacity creates supply bottlenecks that result in higher costs for consumers and the economy. Consequently, as it examines policies to increase natural gas supplies, the Congress also should promote policies that encourage a robust natural gas pipeline infrastructure.

The CHAIRMAN. Thank you very much. Mr. Saunders, let's see if we can work you in with some answers to questions, and if we do not get in what you wanted to say, we will come right back to you. Let me proceed for a few minutes and yield to Senator Bingaman.

We did not ask the Senator from Louisiana at the outset if she had anything. All right.

Mr. Caruso, can you describe the general fuel switching abilities in the United States market between oil and natural gas and what barriers exist to fuel switching?

Mr. CARUSO. Well, there are several hundred thousand barrels a day of fuel switching capability. The actual number is a bit elusive, but nevertheless, we have seen in the last two winters, as a result of high natural gas prices, increased demand for residual fuel oil and, in some cases, distillate fuel oil for electric power generation, particularly for interruptible customers. And as I mentioned, on average it has been between 300,000 and 400,000 barrels a day, as best as we can discern that, because this data is not reported on——

The CHAIRMAN. That is a percent of the oil consumption. What would the percent be?

Mr. CARUSO. It is about 300,000 to 400,000 barrels a day out of a 2 million barrel a day demand.

In terms of inhibitions or things that may—there are a number of State and local regulations which limit the number of hours that a utility, in particular, can burn an alternative fuel, in particular, oil. That certainly does put a significant limitation on the ability to switch fuels.

And the second thing is that in the last 10 or 12 years, the technology of choice for electric power generation has been combined cycle gas turbines, and most of those new plants have been built with limited or no fuel switching capability. So we are becoming less flexible as a Nation.

The CHAIRMAN. And that is the marketplace. There are no rules or regulations regarding it. That is the way they are building them.

Mr. CARUSO. That is correct.

The CHAIRMAN. Again you, Mr. Caruso. Oil reserve calculations have been in the news a lot lately. In January, Shell announced a 20 percent cut in energy reserves. El Paso slashed reserves by 40 percent. Give us a brief explanation of what these cuts actually mean and whether they have made much of an impact on world prices.

Mr. Saunders, when he is finished, would you give us your observations on his answers to these questions?

Mr. CARUSO. I think the reserve recalculations by Shell and El Paso were certainly notable and important for those companies, and certainly their stocks reflect that and Mr. Saunders may go into that more. In terms of the big picture, it is a relatively small change in terms of global reserves. For example, the Shell revision was 4 billion barrels and world proved reserves are 1.2 trillion barrels. So we do not see that as any general trend, as a writing down of the ultimately recoverable reserves.

And the second thing is I do not think that has much of an impact on the current oil market or the current oil price.

Finally, we certainly do not see this as some harbinger of the running out of oil.

The CHAIRMAN. Mr. Saunders.

Mr. SAUNDERS. Mr. Chairman, thanks. By way of introduction, I am Jay Saunders. I am an equity analyst at Deutsche Bank, so I am concerned with these issues from a company perspective.

We have checked this out with Shell and we, of course, have been worried about this spreading to other companies and have not found much evidence within the integrated space at least, and I think the EMP's as well, that this is an issue that is going to be widespread in the industry. However, I think there is a big problem with transparency, and SEC is concerned about this in the reporting requirements.

I would reiterate what Guy just said in that I do not think this should imply that there is any less oil, say, or natural gas left in the world. Part of Shell's downgrade, for instance, had to do with the reclassification of reserves which hinged on not whether the oil was in place or the gas was in place, but whether they could get that oil or gas to market, whether it was commercial. So I think this is more of a timing situation in Shell's case, and in fact, there was a portion of that 20 percent reserve booking that is going to be rebooked, I think, here, very soon because one of these fields became commercial with government sanction.

So I do not think there is reason to be too alarmist here, but from an SEC perspective and a reporting perspective, I think it could be pretty beneficial to transparency in the equity markets.

The CHAIRMAN. Let me follow with you, Mr. Saunders. We have been experiencing a period of sustained high oil prices. Do you think that the investment community now believes that these high prices are a new reality? Has the industry accepted the high prices to the point that investment behavior and expectations have changed?

Mr. SAUNDERS. It is a really good question because my piece of the business tries to value these companies on what we call mid-cycle prices, your long-range prices. Right now, for various reasons, there is an increasing thought that, well, our mid-cycle range is several dollars higher on oil and probably a dollar or two higher on natural gas.

Personally I think we are in for 2 years of pretty high prices. My forecast is not too different from what Guy and his team have come up with at EIA. Longer term, I think we are an opportunity-rich world for oil and natural gas with high returns on our projections for internal rates of return.

I do not think we are in a situation where we are going to have $30 oil forever, but I just think it is going to take 2 years to bring these back down.

But to get to the crux of your question, we are seeing that the psychology is definitely turning and there are theories out there that we are going to have relatively high prices forever. And you can see this actually in the futures curve of the oil markets. I mean, a year ago this time, you had prices that were at similar levels. Yet, your price 5 years out, say, on the NYMEX futures curve was about a dollar or two lower than it is now. Typically that price is an anchor far out and it does not move very much. Now we have a much higher price further out, which suggests, as you suggested, there was a change in psychology here.

The CHAIRMAN. Mr. Caruso, I have a general question and I guess I should have had the answer many months ago, but I somehow did not. You have explained that waiting out there in the wings for new production of electricity from various sources of supply, that it has all moved in the direction of natural gas. You described that as not being very flexible because of what they are building.

Do we know how many plants remain to be built where the companies have agreed that they are going to build natural gas burning power plants? Are there 5, 15? What is the number?

Mr. CARUSO. In our long-term outlook to 2025, we believe there will be 356 gigawatts of new electric power generation needed in this country and about 60 percent of that is estimated to be natural gas combined cycle units. So at least 60 percent we believe will be new natural gas combined cycle units and about 30 percent coal-fired power plants, the remaining 10 being renewables, mainly wind. I see this trend continuing.

The CHAIRMAN. Thank you very much. In just a moment, I am going to turn it over to Senator Bingaman or Senator Craig, and then we will proceed in a normal manner. We want to make sure that Mr. Saunders gets a chance to state what he would like. I have to go to a markup of the budget.

But I want ask you, Mr. Sharples. I am getting very tired of hearing witnesses that I have a lot of confidence in, because they seem to know what they are doing, talk about the American production of natural gas. And they all seem to say, well, we still have a lot of natural gas in America, and I feel very happy and say is that not nice. We are going to get a lot of natural gas. And then comes the word "but". And the word "but" is always followed by a sentence or two saying we do not know how to get it produced. There are too many obstacles. Then you follow on with statements like, "but there is a lot of it there."

Other than Alaska, I am beginning to wonder what this is all about. I mean, is there really a net positive in terms of natural gas that is available in continental America that we are not getting because of rules, regulations, or something, or are we just kidding ourselves?

Mr. SHARPLES. I think the first thing I would say, Mr. Chairman, is to call attention to the very comprehensive work in the National Petroleum Council, work which goes into area by area, basin by basin, and tight gas by tight gas, to answer your question in great detail.

But in summary, I would say that we feel that we are going to struggle to grow as an industry our domestic resource. The question is how fast do we decline. In fact, if you layer onto that the LNG issue, it becomes a race between how fast do we decline the domestic resource and how fast can we bring in alternative energy. So we frankly get to the relatively almost arbitrary discussions, are we going to decline at a half a percent a year, 2 percent a year, or grow at 1 percent a year. I do not think there is a magic bullet within the domestic resource base that will solve the problem.

The CHAIRMAN. Well, before I yield to Senator Bingaman, let me just state for the record, as far as my views are concerned, a few years ago I would have looked at this and said there is a chance we will catch up. But then I found out what was happening to the electricity generation plants of America, electric utilities. Everything was going to natural gas-producing power plants. At one point there were 15 waiting to come on line. There were as small as 750, but most of them were 1,000 megawatts. When I saw that and saw what was happening, I came to the conclusion that so long as we were going to have that as America's future instead of some other mix, be it clean coal, be it nuclear, whatever, that I never thought we would catch up, especially since so many other people are using it, the fertilizer industry, houses, all kinds of appliances. It is such a fantastic fuel.

I remain now as the chairman of this committee very, very perplexed. Unless something happens out of Alaska that is a barnburner, I think we are going to be getting further and further behind in terms of demand versus supply.

You have implied today for the first time that I have heard that the solution may very well be LNG, whichever one of you said that. Did you say that, Mr. Koonce, or who said that?

Mr. KOONCE. I think we both said it.

Mr. SHARPLES. We both alluded to it.

The CHAIRMAN. That sounds neat, but to me, let me say it sounds very much like we just got out of one problem and we are jumping right back into another. The first problem was we let ourselves get into a mess where we cannot produce enough crude oil so we are stuck buying it from all over the world, friend and foe. We thought we were going to be great. We were never going to do that with natural gas. And it would seem to me, Senator, that we are right back there because, to the extent that we substitute LNG, it is going to be from someplace else in the world, not us. That may be a great plan.

But I would hope that we would try first to produce some flexibility in terms of American production, but I am not sure we will get there. This bill sought to do that, but it has got some hang-ups right now. It would have tried to produce three other kinds in due course, plus a nice little shot of wind coming in.

With that, I am going to yield to you, Senator Bingaman, and thanks to all of you for coming.

Senator BINGAMAN. Thank you very much.

I thought maybe before we ask any more questions, should we just ask Mr. Saunders to summarize his testimony so we have the benefit of that? I think that would be a useful thing. Why don't you go right ahead?

STATEMENT OF JAY SAUNDERS, ENERGY ANALYST, DEUTSCHE BANK AG

Mr. SAUNDERS. Thank you, Senator Bingaman. I will just keep this short. I appreciate the opportunity to comment on what looks like to me another 2 years of high crude oil, natural gas, and petroleum product prices. I am coming at this from Deutsche Bank from an equity perspective. I am concerned about these prices for these commodities because there is a pretty strong correlation between those and equity performance.

While I do not think that there is a permanently higher price level, as I mentioned earlier, for these commodities, I do believe it is going to take some time. It is going to take 2 years to get us back to what has traditionally been a normal level for these prices.

In the interest of time, I will just summarize with some bullet points here and request, of course, that this is entered into the record.

World oil markets are caught in a vicious cycle of rampant demand, a cohesive OPEC, the weak U.S. dollar, a consequent increase in speculative froth on oil futures markets, production instability in Iraq and Venezuela and global terrorism. I do not think it is any mistake or any manipulation, say, that the west Texas intermediate crude price has approached the $38 per barrel that we saw this time last year in advance of the invasion of Iraq, which itself was the highest level since the Persian Gulf War.

The largest influence on the oil markets are OPEC, which has been tweaking supply to keep prices high, and demand as the economy recovers, particularly in China. Together, both of these forces are keeping global oil inventories low.

Low threats to OPEC's market share leads me to expect that the cartel can maintain prices at relatively high levels for the next 2 years.

More close to home for the American consumer, these tight market fundamentals are making for what in my view will be another year of high gasoline prices. This summer when Americans hit the roads, gasoline inventories will be at least as low as last year when consumers paid $1.57 per gallon at the pump, and that is the same level that the EIA is forecasting for 2004 in full.

There are some caveats to this. I think you could see gasoline's current price fade as you see refineries in the gulf coast and the east coast, as well as the Midwest, come up from annual maintenance. That should be happening early this month and then by the end of the month in the Midwest.

You could also see a little bit lower demand. This time last year we were faced with very high gasoline prices and a similar outlook, as your demand really did not materialize, for several reasons, until the late part of the summer and we saw prices come off very quickly.

Finally, you could see imports rise very strongly here relative to where they have been over the past several months.

These high oil prices I think will aggravate the fundamental in other areas. We have talked about natural gas. Growth in liquified natural gas, LNG, I do not think is going to happen in any significant way until around 2007. Low U.S. domestic production and the declining rates that we have talked about until then are going to keep prices, I think, pretty high.

Further, to gasoline. Just a few quick comments. I think what we need to look at here is the premium to crude, which is at a similar level right now as it was this time last year. The question I have is, are we going to see this price come off very quickly like we did last year when imports came and just pushed the price down, or are we going to see it actually rise further, or are we going to see it rise and then stay at that level for several months here?

The answer to me lies, number one, in crude prices which I think are going to come down, but they are going to remain high. Our forecast this year is about $31 for west Texas intermediate, which is about $3.50, to get at the psychology question earlier, higher than what Wall Street analysts are estimating this year. If those crude prices come down to $31 even, that is going to take gasoline with it, but because of these what we call boutique fuels in the industry—this is low sulfur gasoline that is starting this year and low sulfur diesel in 2006—I think this is going to put a relatively high floor on your product prices in addition to the elimination of MTBE not only in California but also in New York and Connecticut.

So to me, to summarize all this up, I think you are looking at a pretty high crude price here relative to the $22 that we have seen over the long term, and to get out of this cycle of rampant demand and what has been relatively low non-OPEC production growth, as these companies try to move out of mature areas like the North Sea and the United States and into growth areas like the Caspian and West Africa and Russia that are more politically sensitive, I think as they enter this growth phase, it is going to take some time and it is going to keep this cycle of very strong demand relative to supply from OPEC constraint—I think that is going to keep the cycle going for a couple years. And it is only going to take a shock to get us out of this situation, maybe not as dramatic as we saw on 9/11. Of course, that took prices down for a brief period of time, but I think we need some kind of supply and demand shock near term to get us out of this cycle.

Thank you.

[The prepared statement of Mr. Saunders follows:]

PREPARED STATEMENT OF JAY SAUNDERS, ENERGY ANALYST, DEUTSCHE BANK AG

Mr. Chairman, I appreciate the opportunity to comment on what looks to me like another two years of high crude oil, gasoline and natural gas prices that will be prone to spikes along the way. As an energy equity analyst at Deutsche Bank my concern with the outlook for these commodities stems from the relationship of oil prices to equity performance. While I do not think that we face a permanently high price level for these commodities, I do believe we will not see a correction closer to historical averages until 2006 at the earliest.

I'll highlight several points to summarize the current strength in oil prices, which in turn has led to high gasoline prices and fears of $3/gallon by the summer, and request that my full testimony be entered into the record.

- World oil markets are caught in a vicious cycle of rampant demand, a cohesive OPEC, the weak U.S. dollar, a consequent increase in speculative froth on oil futures markets, production instability in Iraq and Venezuela, and global terrorism. It's no mistake that WTI oil prices have neared the $38/bbl level of a year ago, in advance of the Iraq invasion, which itself was the highest level since the Persian Gulf War.
- The largest influences on the oil markets are OPEC, which has been tweaking supply to keep prices at a higher level than in the past, and demand as the economy recovers. Together these have kept global oil inventories low and prices high.
- Low threats to OPEC's market share leads me to expect that it can maintain prices at a relatively high level through next year.
- More closely to home for the American consumer, these tight market fundamentals are making for what in my view will be another year of high gasoline prices.
- This summer, when Americans hit the roads, gasoline inventories will be at least as low as last year, when consumers paid $1.57/gallon at the pump, the same level the Energy Information Administration (EIA) expects for 2004 in full.
- There are some caveats that could allow gasoline's current price strength to fade. Production could rise strongly after a brisk maintenance period completes at refineries on the Gulf and West Coasts, where operating rates were extremely low, and the U.S. Midwest. Demand growth could slow. Imports may rise as supply chases currently high prices.
- High oil prices will aggravate fundamental tightness in other petroleum-based areas as well. U.S. natural gas markets need more supply, but liquefied natural gas (LNG) will not come until at least 2007. Low U.S. domestic production and rising demand will keep prices high until then.

Further to gasoline, which is particularly important to this discussion at this time of year, several questions need answering. Will prices come off current peaks into the spring, as happened last year? Will gasoline prices continue rising, as in 2001, before falling just as fast under the weight of an import rush? Will prices rise and stay high as imports fail to sate demand? On balance, I expect product prices to fall—U.S. product inventories are 4% higher than last year, and overall OECD inventories are not as tight either—but settle at relatively high levels, and maybe spike further in between.

While the extent to which gasoline prices fall is uncertain, the pattern will likely be volatile due to a lack of surplus supply. Gasoline imports have dropped in volume due to demand diversion elsewhere. At the same time, the higher-quality nature of U.S. gasoline lessens the amount and complexion of these imports, which are more often coming from a wider variety of less stable countries and in a form that requires further treatment to make finished gasoline. Domestically, what have become specialty gasoline grades will be more difficult to make as summer emissions requirements constrict production capability. The production difficulties from these new fuels will only increase with new requirements through 2006 as the ingredients require more intensive manufacturing processes.

A year ago, this committee faced a similar gasoline market only to have weak demand in the spring on wet weather and high imports ease prices. This year, we may not be so lucky as a stronger economy and declining automotive fuel efficiency with greater penetration of sport-utility vehicles in the passenger car fleet drives demand. At the same time, gasoline production capacity remains constrained as cleaner product specifications usher in capacity closures and investment that has not translated, unlike in the past, into capacity growth. All these dynamics, in addition to a shaky Venezuela, which normally supplies 10% of U.S. gasoline imports, have the U.S. shaping up for another high-priced driving season. Gasoline's price premium to crude has reached last year's peak, which occurred both a year ago and in August, and stand higher than at any time in 2002.

The price outlook for crude oil, part and parcel of gasoline's prospects, looks similar. Non-OPEC production is growing only slowly as companies struggle to move from declining production in mature areas, like the U.S. and North Sea, to more politically-sensitive regions, like West Africa and the Caspian. Further, Iraq's problems are taking longer-and-longer to fix, and the risks of renewed civil unrest are rising into the summer's power transition. Finally, Venezuela production has recovered somewhat from the strikes of a little over a year ago but remains sensitive politically throughout the effort to re-call President Chavez.

The outcome of these dynamics, at a minimum, is another year of high prices—just yesterday Deutsche Bank moved from what originally was a bull view of $25.50/barrel for WTI in 2004 to $31, or about the level of 2003, against the Energy Information Administration's (EIA) $30.40 expectation. The trends into 2005 say that Iraq and Venezuela will still be struggling, Russian output growth could slow, and that as long as demand stays robust, OPEC can support prices again. We expect WTI to average $27 in 2005, or lower than the EIA's $28.38.

Longer-term, I continue to believe the post-1999 price rally has taken oil markets to unsustainable levels, and the combined impact of higher non-OPEC investment and lower demand growth will cause a price reversion closer to OPEC's baseline revenue requirement of around $23/barrel WTI. This shakeout could take two years. While product prices should flatten with the energy complex in general, the introduction of low sulfur diesel and gasoline, and the consequent complexities these introduce to the supply system, could support relative product prices into 2006. At the pump gasoline prices will fall with crude oil, and refinery run rates should rise following investment by more efficient companies. Finally, demand growth could slow with higher fuel economy standards, as the EIA assumes in the Annual Energy Outlook 2004 (AE02004).

U.S. natural gas prices, which seem more closely linked to oil, see similar upside pressure. While here again I do think prices will drop, with the LNG cavalry charge not coming until 2007 it will also take time and a demand downturn that may only come at the expense of the ongoing economic recovery.

Only shock treatment may provide a near-term escape from the energy complex's vicious cycle, but a cohesive and comprehensive energy policy could soften the landing and help us avoid the cycle again.

Further details from the Deutsche Bank Energy Team follow on all the topics I've mentioned.

Easy OPEC discipline. OPEC's oil production remains hard to gauge, but there is a strong body of evidence arguing spare capacity is increasingly concentrated in Saudi Arabia. At the same time, structural decline in the non-OPEC regions is gathering pace, heightening the impression of supply tightness.

In Venezuela, conventional oil production has been steadily declining since early 2001, even setting aside the collapse in production in January 2003. Venezuela conventional oil may well have reached a 'Hubert's peak'. The government has already prioritized heavy oil projects ahead of conventional crude. These plays have the dual advantage of off-quota production, and international oil company (ICC) funding, and we suspect that setting aside the politics of the massive restructuring of state oil company PDVSA, that there are fundamental decline rate and conventional reserves replacement issues in Venezuela conventional crude.

Nigeria's onshore and shallow water production—its conventional heartland—has clearly been impacted by civil unrest and under-investment. Royal Dutch/Shell's recent reserves downgrade there was a reflection of the slow pace of infrastructure development, and, we suspect, the increasing complexity of onshore oil developments, combined with companies' reluctance to invest in marginal fields with heightened operating (read political) risk. Deepwater oil growth should halt the slide, but new delays are creeping into an already-long queue of potential developments. Nigeria seems to be running close to full capacity, and hardly looks a threat to OPEC discipline this year.

The pre-war concept that Iraq's oil production would grow swiftly to 2.8 mmb/d and beyond, once the Saddam regime had been changed, is in tatters. Today, Iraq is pumping a mere 2.0 mmb/d. The Kirkuk fields and the 'northern' pipeline that links them to Ceyhan are shut in due to security problems. The southern oil fields, in the Shiite areas, are exporting some 1.6 mmb/d via Basra, with potential for a further 0.5 mmb/d in spring from the re-vamped Khor al-Amaya port. Behind that stark reality, there seems to be strong evidence that Iraq's oil facilities were systematically mismanaged and under-invested, and that oil-for-food vintage reports of dire declines from Saybolt, for much of the 1990's, were real, rather than politicized. Most troubling, armed militias seem to be guarding oil facilities, a tactic likely to degenerate into infighting, once Iraqi leadership is installed as early as June. For now, the Shiite regions in the south are producing oil from fields relatively untouched by sabotage. That situation could change quickly: the Shiite leadership wants elections quickly, against the wishes of the Coalition. The risks to Iraqi oil production from infighting are real. We expect Iraqi production to trickle up to 2.5 mmb/d by year-end, again presenting no threat to the oil market in 2004.

Aiding OPEC's cause, non-OPEC production decline rates remain a key oil industry challenge. Larger publicly-traded IOCs are slowing investments in mature basins and shifting into replacement infrastructure-led plays. That shift takes time, and is leading to downward pressure on estimates for non-OPEC supply. West Africa deep water and Russia remain the core non-OPEC growth regions, and these plays, combined with base declines elsewhere, take us to a total non-OPEC growth estimate of 1.1 mmb/d in 2004 (less aggressive than the ETA's 1.4 mmb/d). That rate of non-OPEC growth is 400 kb/d below our expectations for oil demand growth in 2004. That, combined with limited growth potential this year from Iraq, plays firmly into the hands of OPEC's price hawks, and points to strong oil prices in 2004.

Robust oil demand. Estimated global oil demand growth of nearly 2.0% in 2003 looks relatively healthy after three years of sub-par performance averaging only 0.7% per year 2000-2002. Oil use in 2003 was artificially boosted by at least 500 kb/d more than it would have grown without cold northern hemisphere weather, Japanese nuclear outages, high natural gas prices and low hydro levels in Europe, all of which led to fuel switching into oil. Nevertheless, even without these unusual events, oil demand would have been up a relatively healthy 1.0 mmb/d. We look for demand to grow 1.5 mmb/d in 2004 and 1.6 mmb/d in 2005, driven mainly by higher global GOP growth.

The consensus estimate for global GOP growth in 2004 is 4.2% (and 4.5% for Deutsche Bank), following a 3.3% rise in 2003. The current consensus for 2005 is 3.8% (DB). The average rate of global GOP growth calculated using IMF data over 1998-2003 was about 3.2% per year. In view of the above-average growth, and the potential for some of the "unusual" factors of 2003 to persist into 2004, we see upside risk to our 2004 oil demand projection, especially given that China and the U.S. are both expanding at the same time.

The U.S. accounts for about one quarter of the world's oil use, and despite the occasional impacts from fuel switching and weather, growth in oil is still largely determined by GDP. A year ago, the consensus forecast for 2004 GDP growth in the U.S. was 3.6% and now stands at 4.6%, and 5.2% from DB. If achieved, this GDP would exceed the robust 4.3% rate achieved in 1997-1999 when oil demand growths averaged 400 kb/d annually. In 2004, we expect U.S. oil demand to climb to 20.4 mmb/d, or a similar 370 kb/d (EIA 440 kb/d), and we expect at least 360 kb/d growth in 2005, or less than the EIA's 480 kb/d on rising transportation and industrial use.

As in 2001, China has had a major influence on high crude prices. Apart from the sheer volume of import increase to satisfy rising demand, China's relatively simple refineries require a higher-quality crude barrel, often from West Africa. These long-haul imports not only deprive the U.S. and Europe of incremental supply but also buoy freight rates, which in turn get passed through to crude prices. The signs of demand maturation evident in China in 1998-2001, when demand growth averaged 4.3% annually, have faded. In 2002 demand grew by over 6% and preliminary figures for 2003 suggest a rise over 10%. In 2003 China (5.48 mmb/d) surpassed Japan (5.43 mmb/d) as the second largest global oil consumer after the United States. The consensus on China's long-term yearly economic growth is in the area of 7.5%, and the 2004-05 estimates are above that. Economic restructuring could eventually lead to lower oil/GDP ratios, or a banking/currency crisis could unhinge GDP growth, however, near term expectations for strong economic growth could keep oil demand rising by 6-7% annually in 2004-05.

Positive demand surprises elsewhere? An economic recovery is underway in Japan, where economists estimate GOP grew by 2.3% in 2003 and expect it to grow at that rate again in 2004. This reversal comes after two years of stagnation. Furthermore, the nuclear crisis there that boosted oil demand in 2003 has not yet been completely resolved. GDP revivals are likely boosting oil demand in Argentina and Brazil, enhancing the prospects for the entire Latin American region outside of Venezuela. With rising cash flows from oil sales, oil consumption in the Middle East seems to also be growing robustly. In our view, the potential for demand upgrades in the non-OECD countries looks good.

Downgrades to these forecasts could come from lower GDP, higher average oil prices, or the potential for atypical events (like a warm winter) to lower demand rather than increase it. The economic recovery in the U.S. seems well entrenched for 2004 and with interest rates still low at this point in the cycle, good growth in 2005 seems likely. Should China stumble, all of Asia could suffer, but the timing of such an event seems impossible to predict. Strength in Asia (including China) is probably encouraged by the nascent GDP recovery underway in Japan.

OPEC and prices. Currency impacts suggest higher OPEC-driven dollar denominated prices as U.S. dollar weakness presents good justification for OPEC holding oil prices at the upper edge of its price band. OPEC ministers have been complaining loudly about the impact of the weak U.S. dollar on purchasing power. In January 2000 the U.S. dollar and the Euro were trading at about parity. It now takes about U.S.$1.25 to buy one Euro. Currencies fluctuate, and over the entire period since the start of 2000 when OPEC announced its $22-28 desired range for the OPEC basket price, the currency translation has been more often in OPEC's favor. Nevertheless, the North African and Gulf OPEC members who have significant trade with Europe are justifiably unhappy about the decline in the value of the dollar.

As long as the U.S. dollar is weak, we suspect that OPEC will try hard to keep the Euro value of its crude from going much below $22, and this implies that the dollar price will hover near the $28 top (and not the $25 middle) of the OPEC band. We do believe that the Euro is likely to gain advocates for pricing oil in certain markets (Russian sales to Europe, for example), but the complications in switching the long-standing international payment system suggest that this is unlikely to be a sudden move.

One of the few bear cases for oil prices stems from speculative hedging against the weak U.S. dollar in U.S. dollar-denominated oil. Along with the popularity of commodities in general, speculative interest in crude oil has skyrocketed over the past few years. A strengthening of the U.S. dollar could spark a dramatic sell-off in crude futures markets. Further, a major psychological deterioration in perceived market fundamentals could do the same. Cognizant of this risk, OPEC has chosen to at least voice an intent to maintain currently-high crude prices, reflected in two consecutive surprises in quota reductions last September and early February.

OPEC quota pressures low. Most of the OPEC countries have plans for capacity expansion, but the general trend for upstream capital spending within OPEC seems to have mirrored the "modest" pattern set by the international oil companies. Last September we estimated that OPEC's capacity to produce would total some 37 mmb/d in 2006. Our current estimate for 2006, following on Iraq's slow recovery, is more than 3 mmb/d lower. Development of Iraq's reserves is almost certain to take longer than we anticipated last year, and although we still think Saudi Arabia can increase its capacity, we now see that rising at a slower rate.

The "success" stories in OPEC capacity growth are almost exclusively found where international oil company (IOC) expertise and access to capital are employed. Algeria, for example, grew its capacity by 0.4 mmb/d between 1998 and 2003. With the removal of UN sanctions and the likely end of unilateral U.S. sanctions coming soon, Libya may be the next OPEC member to implement such a strategy. The good news for OPEC is that rising IOC production in many countries appears to have been accommodated via a dramatic decline in national oil company (NOC) production. The NOCs have effectively made room—or far more room than might have been expected—for the IOC output. This may turn out to be especially crucial as deepwater Nigerian production starts to flow. In the critical 2004-2005 period, we expect the likely inability of Iraq and Venezuela to make much progress in boosting capacity to be instrumental in maintaining cohesion within the cartel.

Although we still see OPEC maximum capacity expanding by 2 mmb/d over the next two years (from 29.8 mmb/d in 2003 to 31.8 mmb/d in 2005), almost 75% of this growth is in Nigeria and Iraq where plans could easily go awry. In Saudi Arabia, having, but not necessarily using, spare capacity is a policy.

Longer-term reversion, but it will take time. We caution against a bullish, '$25 oil prices forever' view. Major oil companies have stepped back from mature basins spending and are investing in new production provinces. We judge that this will be a successful reserves replacement and volume growth strategy, but it will take time. U.S. foreign policy is clearly linked to generating oil growth from outside the Gulf region. That policy is closely aligned with company aspirations, and basically improves access rates to non-OPEC countries. Major oil company growth projects are being planned and/or built from the Caspian, Russia (proposals for the Murmansk and East Siberia pipelines), deep-water West Africa, and Canada oil sands. Deep-water Angola alone should be pumping 1.7 mmb/d by 2010 (from nothing in 1998). In aggregate, we see non-OPEC growth adding 5.4 mmb/d for 2003-08E, compared to demand growth of 4.4 mbd over the same period.

That said, we see an interesting oil price 'window' opening for OPEC in 2005. Russia's Major Oils are under intense political pressure and scrutiny from the tax authorities, after the Khordokovsky-Yukos affair. The impending divorce of Yukos and Sibneft leaves those companies at a strategic crossroads. At the same time, the government is mulling a tax increase, and dithering on routes, ownership and timing of the various new oil pipelines. Russia's growth credentials are intact, but delays are creeping in, and we suspect that 2005-directed discretionary spend is slipping.

We question the view that Saudi Arabia is suffering from accelerating decline rates. After all, the Saudis did ramp up production from 800 kb/d in December 2002 to 9.4 mmb/d in April 2003, to make up for oil shortfalls across Gulf War 2. However, OPEC has been ex-growth since 1998, and has had little incentive to invest for new production capacity since then. The OPEC oil system looks ill-prepared to fuel a sustained rally in OPEC oil demand, putting oil prices under upwards pressure when major supply regions wobble (for example last spring), or when consumption accelerates (for example this winter's weather and GOP combination).

Mexico's oil industry is also at an interesting stage. Oil reserves have fallen 20%, lining up Pemex with SEC booking rules; giant oil producer Cantarell may have peaked; and capital spending needs to rise substantially from here. Mexico, not an OPEC player but a key element of previous OPEC/non-OPEC alliances, has little incentive to chase a growth strategy, or play for U.S. market share. The real decision rests in whether or not to bring in the Ions.

The seeds of OPEC capacity growth are there. Deep-water Nigeria exploration could add 1.0 mmb/d by 2010. Kuwait continues to mull IOC involvement in its 900 kb/d Northern fields. Venezuela is poised to develop new conventional reserves (Tomoporo), and sanction heavy oil upgrades. Iraq increased its oil reserves by 33 billion barrels in 2003, with a clear implication that growth investment is coming. OPEC's problem, and hence its reluctance to invest, is that most of these projects would be IOC funded. Approving these investments would create growth rates that could be hard to stop (witness Algeria in recent years). It may be far easier to delay the go-ahead for replacement projects, and play the upside in oil prices.

Political events in 2005 also look supportive. Next year will see Venezuela's President Chavez fighting for his political life again. A recall vote might emerge this year, and with elections not scheduled until 2006, he can hardly afford an oil price crisis, and isn't investing enough now anyway for any meaningful growth next year.

With no elections planned for Iraq until after the 2004 presidential campaign, we question if there will be an administration in either of these countries that would dare allocate oil development contracts in Iraq to the IOCs. This year or next year could see the northern pipeline opening again—we are projecting 2.8 mmb/d by end 2005—but equally, fractional infighting could continue to put downward pressure on production estimates, as is the case today.

The Caspian and Angola look set to be the main supply growth regions next year. BP's BTC should be complete in the first half of 2005, and beginning to fill in the second. However, the fields that will fill that pipe won't build up to 1 mmb/d until 2008, and the delay to Kashagan early oil to 2007-08 limits the potential to fill the pipe next year. We expect the FSU to add another 0.7 mmb/d, although that number could disappoint, given current political trends. All told, we see a similarly strong 2005 as the EIA, with our outlook for non-OPEC growth of 1.1 mmb/d (EIA also at 1.1 mmb/d) and demand growth at 1.6 (EIA 1.5). With little momentum from Iraq, the OPEC players can hold their production flat again into 2005, whereas the EIA has 0.5 mmb/d for OPEC in 2005. We recently increased our oil price forecasts for

2005 to $27 WTI on these supportive supply/demand trends and the outlook for a weak dollar.

Downside oil market risks are real, but not until 2006. The oil markets are currently locked in a perpetual loop of low inventories and high prices. OPEC and unusual political events have kept production in check and demand has recovered from the setbacks earlier in the decade. Backwardation in the futures market provides a strong disincentive for the building of commercial inventories and that in turn keeps inventories low. The only way out of this circle is through the application of a demand or supply shock: an economic downturn, a very warm winter, surging Russian or Caspian production, a reversal of decay in Venezuela, or a flood of Iraqi oil. These are certainly worth discussion, but the general evidence on these topics points to incremental and not colossal shifts.

The relationship between oil demand and changes in global economic growth is clear: GDP drives oil demand. The GDP crashes in 1974 and 1980 unmistakably drove oil demand down and it is possible that these circumstances could be repeated. A simultaneous downturn in China and the U.S. might be enough to trigger a serious GDP shortfall, and this in turn could pressure oil prices. However, it is possible to argue that crashes in oil prices tend to be preceded by very sharp increases in real prices. The oil price extremes since the early 1970s typically have been associated with war. A number of economic studies have shown that consumer unease in the face of war reduces spending and it is the combination of higher oil prices and dramatically reduced consumer expenditures that causes GDP to plummet. It might take $35-40 real oil prices ($40-45 Brent) to cause a repeat of the big downturns.

In China, leading indicators (money supply, bank loans) continue to decelerate. Among the G7 nations, a number of recent forecasts suggest industrial demand may peak this summer. In the developing countries, concerns are rising that industrial output is peaking now and could sharply drop into Q2-Q3 2004. The political rhetoric on high oil prices is increasing. Politicians in the U.S., France, Germany, and Japan have recently expressed rising concern over the level of oil prices and the potential negative impact that high oil prices could have on consumers.

FSU production also presents downside. There is no question that Russia, Azerbaijan and Kazakhstan are likely to be the source of much of the non-OPEC supply growth over the next few years. The Former Soviet Union accounts for more than half of the entire non-OPEC growth in 2004 and 2005. Russian production is expected to grow by about 540 kb/d in 2004, and 700 kb/d for the FSU (EIA 700 kb/d also), but this rise is about 50 kb/d lower than our prior assumption because of a downgrade to Yukos' production profile. The CPC pipeline in Kazakhstan should operate at a higher rate during 2004, allowing a rise of about 100 kb/d. In Azerbaijan, the next big jump is expected to come from the 01/2005 start-up of the Baku-Ceyhan (BTC) pipeline. In all of these countries, the potential for significantly higher output than our forecast is low and the possibility of timing downgrades is real.

Status quo reversal in Venezuela? Venezuelan production appears to have stabilized at 2.7 mmb/d, including heavy oil. PDVSA has maintained close to normal production levels in Eastern Venezuela where fields are younger and the oil is lighter. Production in Western Venezuelan has leveled out after a sharp decline (over 500 kb/d) due to inexperience in maintaining old infrastructure and complex "huff and puff' lifting methods. It seems plausible that the lost 500 kb/d could be recaptured, but serious problems involve the long-term loss of reserves due to reservoir damage and unbalanced water/gas injection. Outside estimates of the costs to restore overall capacity to 3.1-3.2 mmb/d by 2005 suggest that it would take $11 bn. With neither the government nor PDVSA having the required investment, on top of tough fiscal terms and political uncertainties, it seems highly unlikely that foreign companies could make much of a difference in the short term.

A flood of Iraqi oil? Iraq's main northern oil artery, the Kirkuk-Ceyhan pipeline, is not operating. The poor state of the facilities appears to be at least as much of a problem as sabotage. It is possible that a restart could occur soon, but even if disruptions could be contained, flows above 250-50 kb/d would be unlikely. In the south, work on rebuilding Gulf port loading facilities at Khor al-Amaya has been underway for several months. Some 350-500 kb/d of exports could be flowing with immediate effect.

Simply adding up the possible incremental exports (0.6-1.0 mmb/d) and assuming this amount of oil is available may not be sound. First, Iraq's oil fields are in dire need of reservoir management. Ultimate recovery has been reduced with field abuse, particularly at Kirkuk in the north. Until wells have been rehabilitated and new investment takes place, it may be unwise to project output growth that may not be sustainable. Second, the Shia population in south Iraq is supportive of the coalition, but there are indications recently that insurgents are trying to move south. If the protection of the Shia population becomes questionable, their support for the coalition could wane and southern oil facilities might then be vulnerable to interruption.

U.S. SPR to the rescue? Another possible source of significant and easily accessible incremental barrels is the U.S. Strategic Petroleum Reserve. It is possible that oil could be sold or swapped out of the SPR and, in fact, this was done in the fall of 2000 by the Clinton administration just before the November 2000 U.S. presidential elections. The Bush administration has generally been opposed to the use of the SPR under almost any circumstances. Bush did not use it during the combined outages in early 2003 caused by the strike in Venezuela, the Iraq war and unrest in Nigeria. It seems difficult to believe that he would use it now. The U.S. Secretary of Energy has reiterated his support for the current fill program that has been adding almost 150 kb/d to global demand for oil, claiming that it was an "insignificant" part of 80 mmb/d of global demand.

Crude oil tightness feeds into U.S. downstream. The year has begun with strong headline refining margins on low product inventories, in part driven by strong demand and an unusual amount of U.S. refinery downtime in Q1. With MTBE phase-out in H1 2004 further complicating the picture, we have increased our global refining margin forecasts from $3.12/bbl to $3.90, with much of that upgrade coming in Asia.

U.S. gasoline remains the dominant force. U.S. gasoline demand continues to rise seemingly inexorably on a surging economy and declining fuel efficiency with greater penetration of sport-utility vehicles in the passenger automobile fleet. At the same time, refining capacity remains constrained on several levels. New product specifications, unlike in the past, do not seem to be adding capacity. In addition, imports have fallen in volume due to demand diversion elsewhere (China). Further, the import complexion has changed, with a greater percentage of imports being blending components, as opposed to finished gasoline, from a wider variety of countries. These dynamics have the U.S. shaping up for another high-priced driving season.

Assuming gasoline demand continues to grow at 1.5% y-o-y and imports stay on trend for a 10% y-o-y decline, U.S. gasoline inventories would still enter the summer lower than last year's 206 million barrels even with a relatively high capacity utilization rate and yield. Last summer, U.S. conventional-grade retail pump prices averaged $1.57/gallon, the same level EIA expects for 2004 in full. However, last summer was helped by a late demand surge and high imports. We expect strong demand, continued low imports and high crude prices to lend upside to $1.60/gallon retail pump prices.

U.S. and Asian gasoline strength has contributed to a wide WTI price premium that also comes from depressed heavy grade values from conversion unit downtime. WTI's inflation plays into the hands of not only complex refiners but the East Coast, with also those with exposure to Brent-based crude. Brent's discount to WTI has averaged $3.80 so far in Q1, against a normal $1.50. The phase-in this year of low sulfur (Tier 2) gasoline, in addition to low U.S. crude inventories relative to Europe, have bid up light, sweet WTI, to East Coast refiners' advantage. At the same time MTBE phase-outs in California, New York and Connecticut, as well as tighter sulfur levels, are limiting finished gasoline imports. U.S. gasoline imports fell from 860 kb/d during Q3 2003 to 720 kb/d over the four months through January, a month in which imports fell 15% below January 2003. Modest European refinery maintenance in Q2—900 kb/d vs 1.3 mmb/d during the previous three years—may help a bit during the critical spring build to the summer if Asia doesn't continue to divert that surplus away from the U.S. In the U.S., Q1 downtime is most prevalent in Marathon, Premcor, Valero, Shell and ConocoPhillips. This high rate of downtime points to firm headline refining margins, but erratic, and disappointing earnings in Q1.

Apart from support from demand growth and capacity constraint, following on capital starvation from the Majors, fuel specification changes in Europe (2005) and the U.S. (2006) girds a longer-term downstream outlook. We expect a final Auto Oil 2 shift for remaining European countries in 2005, to low sulfur (10ppm) diesel. In the U.S., 2004 began the sulfur reduction in gasoline to what will be 30ppm by January 2006, from 120ppm this year. More onerously, refiners have to have 80% of their on-highway diesel pool at a lower 15ppm sulfur level by mid-2006. Japan meets a less stringent 50ppm level in diesel at end-2004. The larger companies have begun to upgrade for these changes, but the second tier players will leave the needed investments to the last minute (witness the maintenance scramble now for MTBE), tightening margins and raising product prices. Asia supply-demand could finally balance in 2006-07, after years of pain, although the history of this segment says that over-investment or a demand problem will stop that happening.

China's role. China's growth has been meteoric, and looks to be constrained only by infrastructure—crude import capacity—rather than actual need. Last year new car sales rose by some 30% to 345,180 and crude imports increased by at the same rate (450 kb/d). Not only does China's gasoline-powered fleet look set to grow, but the government has also reversed a previous tack in support of diesel car construction. Refining capacity, even with the large numbers of small 'teakettle' plants, seems stretched, reflected in the rise in Singapore refinery utilization from 61% in 2002 to 72% in 2003, or fully 170 kb/d. We see upside to our 350 kb/d Chinese growth forecast, and continued fuel oil imports (being used by the teakettles instead of crude oil) could maintain support at the bottom of Singapore's product barrel.

Japan's role has also been significant. While China has claimed the headlines for Asia's downstream turnaround, Japan's role has been just as large. Reversing what had been three years of 2% declines, demand rose 120 kb/d (2.2%) in 2003 mostly on residual fuel from switching out of nuclear energy into oil due to downed reactors. Returning nukes and high inventories argue for a decline this year, but 7% y-o-y GDP growth in Q4 2003, and a consequent rise in estimates for 2004 to 2.4% from 1.9% previously, bode well for demand. Further, refinery shutdowns have tightened the market. Although over-capacity still has some way to go, the seeds for a recovery seem sown.

U.S. gas, as well, is troublingly tight. Coming out of what looks to be a historically (at least near-term) cold winter, strong weather-adjusted withdrawals have shaped an inventory curve that looks to end the winter below 1,000bcf, rather than the 1,100 bcf end-winter level expected only a month ago. With the industrial side of the U.S. economy booming, and domestic dry gas production struggling, gas price strength is likely to remain a fixture. Although we expect 10 or so of the 35 proposals for new LNG terminals in the U.S. will get built this decade, they cannot be completed in time to make much of a difference before 2007. Until then, the only way to balance supply and demand (absent a really warm winter) is to have a high enough price to choke off demand, while trusting that the existing four terminal expansions are completed on time in 2005. We recently raised our U.S. gas price forecast for 2004 from $4.20/mmBtu NYMEX to $5.00/mmBtu ($5.24 EIA NYMEX equivalent), and increasing our 2005 estimate from $3.50 to $4.25/mmBtu (EIA $5.31). Furthermore, we are now estimating a "settling-in" price in 2006 of $4.00/mmBtu.

A strong U.S. industrial production recovery is underway. Reflecting a relatively more efficient demand base and deterioration in fuel switching capability, industrial natural gas demand seems to be recovering quickly. Of the larger sub-sectors, chemicals, petroleum (refineries), non-metallic minerals and primary metals categories are all experiencing growth, providing support for high gas prices. While high oil prices have inhibited switching, declining heat rates from electricity producers keeps natural gas competitive at $6/mmBtu in the winter when WTI oil is around $35/bbl.

Preliminary data for 2003 suggest that U.S. gas production has been weak. While we were expecting good year-over-year comparisons for North American natural gas production for the independent producers (given a steady climb in the rig count over the last 12 months), we have not seen much growth so far, and the majors do not seem to be fairing any better. Some of the declines are due to shifts in corporate strategy as capital spending has shifted overseas. Texas Railroad Commission data (admittedly subject to upward revision) through October shows production down 1.3%, but is in contrast to the EIA's estimate for a 2.2% rise for the same period. In view of what appears to be a deceleration in the gas production growth rate evident in the DOE's data, we are inclined to believe that our estimate of a 1% increase is reasonable.

LNG deliveries have increased over last year from Trinidad train III, more than offsetting a temporary outage from Algeria. A decline of nearly 3% from Canada, partially offset by what seems to be weaker Mexican demand, should mitigate the downward impact of higher LNG volumes and flattish U.S. production. Deep-water Gulf of Mexico output continues to rise, and rig counts are up generally even if drilling remains suppressed in Wyoming's Powder River Basin. Overall we expect a 1% gas production increase to be more than offset by demand to keep gas storage in the "normal" range and gas prices relatively high.

Low storage could cause spikes. The difference in our model-predicted storage withdrawals this winter against last is about 1.5bcf higher/day. The model does attempt to adjust for demand response to gas prices and oil prices, as well as production response to the rig count. Thus, the underlying demand against production 'shortfall' to the above suggests that if the higher withdrawal persists, there would be a strong potential for a gas price spike to balance the market, unless the market is willing to go into winter 2004-05 with much lower storage than last year. Fixing this problem would be helped along by the addition of an incremental 30-50 gas rigs.

Senator BINGAMAN. Thank you very much. Mr. Chairman, I would defer my own questions and allow Senator Wyden to go ahead and ask. He has to run off to the Budget Committee, so he can go ahead.

Senator CRAIG [presiding]. All right. Please proceed.

Senator WYDEN. I thank my friend from New Mexico very much. I know everybody's schedule is busy.

Mr. Caruso, a couple of questions for you because I am very concerned that there are administration policies being pursued now that are going to push gasoline prices up even higher, and I want to walk you through a couple of concerns just for a few minutes.

You said in your testimony that oil supply is very tight right now and that that is a factor in pushing gasoline prices up. Given that, would you not say that it is a bad time for the Federal Government to adopt policies that would further reduce oil supply?

Mr. CARUSO. I would agree.

Senator WYDEN. But the administration is pursuing a policy that is doing just that, that would, in effect, compound what you think is a bad idea, and what the administration is doing is making the current supply situation worse by taking oil from this very tight market to fill the Strategic Petroleum Reserve. I guess my question is how do you justify going out and filling the Strategic Petroleum Reserve when experts are issuing all these warnings about gasoline supply shortages? It just strikes me as incoherent, but I want to give you a chance to respond.

Mr. CARUSO. The Secretary of Energy has asked me to analyze that very point. And our view is it does not reduce oil supply.

Senator WYDEN. It does not reduce?

Mr. CARUSO. It does not reduce oil supply.

Senator WYDEN. By taking it from the private sector and moving it into the Strategic Petroleum Reserve, it does not take it from the supply?

Mr. CARUSO. That is correct. We believe the world oil supply has not been affected by the addition last year of the 120,000 barrels a day of oil, royalty in kind oil into the Strategic Petroleum Reserve. And the reason is that OPEC producers watch very carefully what is going on in the global supply/demand situation and they adapt to, in this case, that 120,000 barrels a day of oil being put into the reserve instead of being on the market. That additional oil is being produced by OPEC. It is not a net loss in our view. It is a net zero.

Senator WYDEN. Well, why do you not supply us for the record that analysis because I think the idea of awarding long-term contracts, as prices were actually spiking up, awarding contracts that are going to run through the summer at a time when prices go up just leaves me baffled. So I would love to see your analysis and take a look at it.

Mr. CARUSO. I would be happy to supply it.

[The information follows:]

This is in response to your request that the Energy Information Administration (EIA) provide you with its assessment of the impact of additions to the U.S. Strategic Petroleum Reserve (SPR) from April 2002 to date on U.S. and global crude oil markets. The average SPR fill rate since April 2002 was 120 thousand barrels per day, with a monthly peak rate of 210 thousand barrels per day. Our overall assessment of how these additions may have affected oil markets can be summarized as follows:

- Given OPEC members' recent demonstrated ability to alter production to influence prices, the actual impact of SPR additions on oil prices could be close to zero. Had SPR additions not been made, OPEC members who operate at variable production levels may well have responded with offsetting output adjustments, maintaining a price and inventory profile identical to that which actually occurred. In this case, price impacts at or near zero are entirely plausible.
- EIA has also developed a standard "rule of thumb" for assessing the effect of unexpected disruptions to commercial oil supply—that 1 million barrels per day removed from the world market has a price impact of $3 to $5 per barrel. Applying this rule, SPR additions, even at 200 thousand barrels per day, would have a price impact of about 60 cents to $1 per barrel. However, because SPR additions were announced and anticipated by the markets, the standard rule may overstate actual impacts.

EIA is aware that some market analysts have recently suggested that the SPR additions have had a much larger impact on oil prices. For example, a representative of the Air Transport Association, was recently quoted in press reports as saying that SPR additions "were adding enough demand to the world marketplace to drive up the price by more than $6 per barrel." In EIA's view, however, impact estimates this high (or even higher) use reasoning that does not withstand scrutiny.

- One claim made is that SPR additions, especially during a time of rising crude oil prices, push prices higher by exacerbating the tightness of the global oil supply/demand balance. However, additions to the SPR at the average SPR fill rate since April 2002, amount to only 0.15 percent of global demand—hardly enough to drive a 25% to 33% price increases in the global market. A variant of the same approach focuses on the share of SPR additions in the overall change in oil demand. However, as Paul Horsnell of Barclays Capital Research puts it, "The world consumed 29.2 billion barrels of oil in 2003, while the SPR grew by less than 0.04 billion [*barrels*]. At the margin, barrels of incremental global demand outnumbered the SPR fill by about fifteen to one." [Note: EIA's figures are slightly different, showing a ratio of 13.4 to 1.]
- Another line of argument focuses on the level of commercial oil inventories, making the assumption that all of the oil that has been added to the SPR would, but for those additions, have flowed into commercial storage, resulting in much higher commercial stocks than the current estimate (as of January 16, 2004) of 265.2 million barrels, the lowest level since 1975. This reasoning, however, relies on key assumptions regarding the operation of world oil markets that are both implausible and mutually inconsistent:
  - First, it assumes no supply response on the part of oil exporters to a change in the level of SPR additions. Given the pre-announced and steady pattern of the SPR additions, it could reasonably be expected that major oil exporters, which have increasingly in recent years sought to reassert control over oil prices by managing output, would in fact produce less if these purchases were not taking place, rather than allowing an equivalent amount of crude oil to flow into commercial inventories.
  - Second, even in the unlikely event that supply remained at an unchanged level in a scenario with no additions to the SPR, the significant lowering of oil prices that the "high impact" analysts claim in such a scenario should have raised world oil demand above the levels that actually occurred. Even with no supply adjustments (unlikely) there would also have to have been no demand response to significantly lower prices (also unlikely) for all of the SPR additions made over this period to have shown up in current commercial inventories.
  - Third, oil companies are unlikely to have to have added to commercial inventories if the SPR oil had been made available. Company inventory positions are at current levels because of cost cutting measures, better inventory management techniques and fiscal incentives. Crude oil has been available on the international market and the companies have chosen to operate with leaner inventories.

What Factors Does EIA Believe Have Significantly Impacted Oil Markets?

Although you did not specifically request it, we thought you might also be interested in our assessment of key factors currently driving oil markets. Since early 2002, a number of important fundamental factors have contributed to high crude oil prices, including rising demand; OPEC production cuts; supply disruptions in Venezuela, Nigeria, and Iraq; and low inventories.

- The rise in crude oil prices to the $27-28-per-barrel range in late summer 2002 only represented a recovery to the levels seen prior to the terrorist attacks of September 11, 2001, which depressed oil demand. By the second quarter of 2003, U.S. economic recovery began to accelerate. Coupled with surging Chinese growth and modest recovery elsewhere, strong economic activity has boosted U.S. and global oil demand significantly. Cold weather and fuel switching from natural gas to oil, both last winter and since mid-December 2003, have added to demand pressures.
- OPEC cut its output quotas sharply at the beginning of 2002, in response to the sharp decline in prices after September 11, 2001. This fourth cut, in a series of reductions that began in February 2001, sharply curtailed oil supplies just as oil demand began its recovery. In less than a year, OPEC reduced its ceiling level (for the 10 members excluding Iraq) by 5 million barrels per day, and actual production by up to 4 million barrels per day. This reduction in supply tightened the global oil balance significantly, resulting in declining inventories relative to normal throughout the second half of 2002. The roots of current oil price volatility trace to these actions, since OECD stocks had already reached the near-record lows seen in 2000 by November 2002, just ahead of Venezuela's oil disruption.
- In December 2002, a strike by petroleum workers in Venezuela drastically reduced global crude oil supplies. The impact was felt most in the United States, the largest consumer of Venezuelan crude oil. Nigerian production was also curtailed in early 2003 due to unrest.
- Crude supply disruptions in Venezuela, Nigeria and Iraq in late 2002 and early 2003 were not fully offset by increased supply from other sources. While there can be no doubt that Saudi Arabia and the OPEC 10 dramatically boosted production following the Venezuelan outage, as well as prior to and following the Iraq war, the initial increases were slow in coming, with December 2002 and January 2003 aggregate production levels down sharply from already-tight November 2002 supply levels. When the surge in OPEC supply did occur, the bulk of the increase (excluding Venezuela) appears to have gone to China and other Asian refiners, at least through the first half of 2003.
- OPEC cut quotas twice during 2003, reducing global supplies. The first was effective June 1, and they later agreed to cut quotas again effective November l. While OPEC members continued to produce more than their agreed-upon quotas, production remained low enough to sustain WTI prices above $30 per barrel for most of 2003.
- By the end of 2003, there was some recovery in product inventories, but U.S. crude oil inventories reached their lowest levels since the mid-1970s. While OPEC appears to have sustained high production levels over the second half of 2003, OECD stocks in November 2003 dipped back below November 2000 levels. Some recovery in either crude oil or product stocks relative to normal has occurred over the last 6 months both in the U.S. and worldwide, but supply has generally been inadequate to meet improving oil demand and at the same time rebuild both crude oil and product stocks. As such, the last year has been characterized by a "cycling" of this shortfall from region to region and product to product.

Obviously, it is impossible to address in full detail all of the important factors affecting oil markets in a brief memorandum. Please feel free to contact us if you have any additional questions.

Senator WYDEN. To me it is not rocket science. Supply is really short. You all are taking it out of the private sector, moving it into the Strategic Petroleum Reserve. And if you are a consumer getting clobbered in Oregon and California and on the west coast, I think you are just sort of incredulous at this.

Given the current west coast market situation with these huge price hikes in California and Oregon, could the closing of that Bakersfield refinery that I have been talking about this morning not cause west coast gasoline and diesel prices to increase even more?

Mr. CARUSO. Well, as I have said, it is a very tight market not only globally, particularly for gasoline in this country. The Shell refinery supplies about 2 percent of California's gasoline and about

6 percent of diesel. Clearly any reduction in refinery capacity does reduce the flexibility to meet a very tight market.

Senator WYDEN. So you think it could be a problem. Do you think the Federal Trade Commission should agree with my suggestion to look at this? Because I cannot find where you are going to make up that supply. As you know, on the west coast, it is unbelievably tight in California, Oregon, and Washington. And you have got these California officials saying they do not understand the case for it. Do you think the Federal Trade Commission should agree with my request and look into this, given the answer you have just given that this could bump up prices even higher?

Mr. CARUSO. The issue of whether the Federal Trade Commission should look into it is a separate matter.

I am just giving you my assessment of what the impact on the oil market would be. Now, whether it is an FTC or Department of Justice or other issue, I could not really comment on that.

Senator WYDEN. At least you have given me an argument to go back to the Federal Trade Commission to use in terms of making the inquiry because to me, again, this is pretty obvious. There is no evidence other refineries are going to come forward and increase supply. You have told us that the supply shortage can bump up prices. So I am not going to quote from the movie, but something has got to give.

Senator CRAIG. Senator, your time——

Senator WYDEN. Thank you, Mr. Chairman. I want to thank Senator Bingaman again for his thoughtfulness.

Senator CRAIG. Senator.

Senator THOMAS. Thank you. Mr. Caruso, most consultants and industry sources reporting natural gas production—it will decline. Your proposal here or your study indicates a different view, an increase in production. How do you explain the difference?

Mr. CARUSO. I think both myself and Mr. Sharples agree that the resource base is quite large and the potential for adding to productive capacity is there.

I think the big issue is will technological improvements and cost reductions allow us to exploit, in particular, the unconventional sources of natural gas, particularly in your part of the country, with tight sands in Wyoming, Colorado and Utah and shale gas and coalbed methane.

We are very optimistic that given the resource base and given the improvements in technology production will increase. However, there is uncertainty about the infrastructure that was mentioned by both Mr. Sharples and Mr. Koonce and uncertainty about the access. Even when it is not on Federal lands, there are other issues that come up in the legal system. So I think that is the difference.

Senator THOMAS. The permitting and so on, which you all have something to do with, plays a role.

Mr. CARUSO. Yes.

Senator THOMAS. Mr. Sharples, much of the gas demand is electric generation and all the generators in the last 15 years perhaps or almost all have been gas. You do not mention anything about alternative fuels. Maybe we ought to be talking a little bit more about our largest resource of fossil fuel, which is not gas.

Mr. SHARPLES. You are right. Senator, we do not have a lot of particular expertise in the arena of coal, but certainly to the extent that clean coal technology can be proven and we can meet the dual goals of protecting the environment and producing economical energy, I personally believe they should be part of the mix.

Senator THOMAS. Well, it seems that we have to make a decision that gas is much more flexible for many other uses, and in terms of a policy it looks like—let me read you a couple things.

There has been a fundamental shift in natural gas supply and demand balance that has resulted in higher prices and volatility. This situation is expected to continue but can be moderated. Greater energy efficiency and conservation are vital near-term and long-term mechanisms for moderating the price. Power generators and industrial consumers are more dependent on gas-fired and less able to respond to utilizing alternative sources of energy. This is the recommendations or the ideas of the summary by the National Petroleum Council.

Now, none of you have mentioned any of those things, more efficiency, conservation. Production is very important, but production is not the only factor here. Is that not right?

Mr. SHARPLES. Absolutely. If I may comment. My purpose in referring several times to that study is that I believe that all the findings are significant and need to be considered in terms of—just using the title of that paper—Balancing Natural Gas Policy. I think there are approximately 10 findings in that study. I think all of them are significant and many deal with demand issues, energy efficiency, alternative fuels. My comments were directed to the one specific area that we know best which is gas supply.

Senator THOMAS. Yes, I understand.

Mr. Koonce, I know I am about through here, but you talked about pipelines and the ability to do things. What about RTO's? You said the Feds have to have all the responsibility on interstate. If we could get effective RTO's, would that not be an opportunity for the States to be involved in what you do with transportation?

Mr. KOONCE. Yes, Senator. I am glad you asked the question. Our company operates 25,000 megawatts of generation and it is coal, oil, natural gas, and nuclear. And we are also the operator of the Cove Point LNG terminal and we are a producer of natural gas with about 6.3 tcf approved reserves.

When we look at the full measure of the legislation that has been drafted, we are very encouraged by a number of things. One, we do not view that any one element of the package is really the magic bullet, but we do like the idea that there are deep gas incentives. There are deep water incentives. There are pilot projects to deal with permitting out in the Rocky Mountain basin. So combined with initiatives to improve access to natural gas supply, we also look at the electric side and we look at RTO formation and voluntary participation in that as a means to address some of the demand issues created by gas-fired generation.

In our own region of the country in the last 3 years, we have developed about 6,000 megawatts of gas-fired generation to meet our on-peak demand. The energy bill that is drafted really incents all generators to try to achieve the most economic dispatch of generation, and added with that the time- of-day pricing element of this legislation so that people will be incented to use energy in on-peak versus off-peak hours efficiently.

So when you take the combined dispatch of a large region, can you get a higher efficiency rate out of a coal plant to cause a gas-fired plant to not have to run on peak? Can you get those type of efficiencies? Can you change the consuming behavior through time-of-day pricing so that you get better utilization out of the existing infrastructure? That, combined with the LNG initiatives and combined with the production initiatives, we think serve to provide enough balance to allow all these measures to help solve the problem.

Senator THOMAS. Thank you.

Senator CRAIG. Thank you, Senator.

Senator Bingaman.

Senator BINGAMAN. Thank you very much.

Mr. Caruso, let me ask you about your view as to what can be achieved through a more aggressive approach to energy efficiency with regard to use of natural gas. My understanding is that this National Petroleum Council report that Mr. Sharples and others have referred to has in it—one of the approaches that they have in there, which is a more aggressive approach to energy efficiency, predicts that we can decrease overall gas demand to 26 or 27 tcf rather than 31 to 32 tcf by 2025. Now, your predictions and your charts that you gave us, as I understand them, assume we are going to need 21 to 22 tcf by 2025.

Mr. CARUSO. 31 to 32.

Senator BINGAMAN. 31. That is what I meant to say, yes, 31 to 32.

In reaching that conclusion, you evidently are discounting the prospect that we might actually reduce that number by any of these energy efficiency efforts that the National Petroleum Council refers to. Can you explain why you think that is not going to happen?

Mr. CARUSO. Yes. I think it is a little bit difficult to compare the NPC study with EIA's outlook because I am not sure what they are assuming for the actual price to get to that lower demand number. I have a feeling that a considerable amount of the reduction in demand is price-induced, which, of course, does lead to improved efficiencies.

But I can say we have taken into account considerable improvement in energy efficiency even at the 31 tcf level. For example, the average new gas-fired combined cycle plant by 2025 will be consuming 27 percent less natural gas than the existing fleet of natural gas-fired electric power plants.

So as I understand the methodology of the NPC study, it sees a lot of the industrial demand for gas being "destroyed" by the high price, getting you down to the numbers you quoted, 26 or 27 tcf compared with 31. We are certainly going to be looking in more detail at the NPC analysis. In our view most of that demand will actually continue to reside in this country as opposed to being moved offshore, for example.

Senator BINGAMAN. Let me ask Mr. Sharples to comment on that. Do you think this NPC prediction that we could get gas demand down to 26 or 27 tcf by 2025 is just wishful thinking?

Mr. SHARPLES. I do not believe it is wishful thinking. I think, though, it is a bit like the answer Mr. Caruso gave in terms of gas technology. We look at the tremendous improvements in energy efficiency that have been evidenced in the past, and if you try the very difficult role of predicting future technology improvements, there is an element of that embedded into this. But certainly at these prices, there will be tremendous incentives to use less. There will be tremendous incentives to institute, for example, time-of-day pricing so that we can balance the load a little bit. As capital stock is replaced, the tremendous incentive to purchase more energy efficient appliances. The NPC study assumes that you will see continued effect in that regard, not just moving demand overseas but influencing the decisions of both the industrial power generation, even the residential consumer to purchase more energy efficient appliances.

Senator BINGAMAN. Let me ask Mr. Koonce about this Alaska pipeline, or any of the rest of you. I gather a lot of you build into your projections here—and Mr. Caruso, you do—a very substantial increase in natural gas production in Alaska, and that is assuming we will have a pipeline that will be built by 2017, 2018, and that is when you think it will come on line.

We have this proposal that Mid-America has come up with to construct a pipeline, an alternative proposal. Would that substantially shorten the time period for getting that gas down here and dramatically increase the amount of gas we could see from Alaska in the near term? Do any of you have thoughts on that? Mr. Sharples, do you have any thoughts or Mr. Koonce?

Mr. KOONCE. We certainly are excited about the prospects and we are pleased that Mid-America has stepped forward and is attempting to take a lead in trying to bring about the development of this pipeline. Estimates say as much as 4 bcf a day could flow into the domestic infrastructure from this.

Again, I think whether it is the Alaska natural gas pipeline or whether it is LNG infrastructure, whatever it may be, I think the most important thing we can do is to make the siting and the authority clear so that project proponents like Mid-America or Dominion or whoever else can know once and for all where they go and how they get the authority to put the infrastructure in place that they want to see happen. I think that is one step.

I think more generally clear Federal authority in terms of siting will help the Alaskan pipeline development, but will also help LNG development and city development, be it New York City or elsewhere.

Senator BINGAMAN. Thank you.

Senator CRAIG. Senator, thank you.

Now let me turn to the Senator from Louisiana.

Senator LANDRIEU. Thank you, Mr. Chairman. I do have an opening statement I will submit to the record.

Senator CRAIG. Without objection.

[The prepared statement of Senator Landrieu follows:]

PREPARED STATEMENT OF HON. MARY L. LANDRIEU, U.S. SENATOR FROM LOUISIANA

Over the last few years our Committee has held a number of hearings on the volatility of energy prices in this country and their impact on the economy both for consumers as well as industrial end users. Much of our time has been spent focusing on oil and natural gas which account for about 65% of annual energy use. Today provides us with the opportunity to discuss the Energy Information Administration's (EIA) Annual Energy Outlook for 2004 on supply, demand and prices for oil and natural gas as well as coal, nuclear and renewable energy sources.

As a Senator from Louisiana I am particularly interested in the analysis and testimony on the subject of natural gas. Not only does my State produce a considerable amount of natural gas for use by the rest of the country, ranking second among states in production, but we are also a significant consumer of natural gas. Louisiana is a hub of production for the chemical industry which uses natural gas as a fuel and as a raw material.

PROBLEM

For almost 4 years, natural gas prices have remained at levels substantially higher than those of the 1990s. In fact, U.S. natural gas is the most expensive in the industrialized world.

Industrial end users of natural gas like the chemical industry are facing a sustained period of high natural gas prices unlike in any period since the late 1970s and early 1980s. Key industries that rely on natural gas have responded over the past few years with curtailments in production, idling of plants, and in some cases permanent plant closures. While U.S. chemical makers have lost an estimated 78,000 jobs since natural gas prices began to rise in 2000, Louisiana alone has lost 4,400 chemical related jobs over the same span or about 15% of that work force.

HOW DID WE GET HERE?

There has been a growing gap between demand and supply of natural gas on the horizon for some time. EIA in their Annual Energy Outlook for 2004 now projects that total U.S. natural gas consumption will increase from 22.78 tcf (trillion cubic feet) in 2002 to 31.41 tcf by 2025. However, total U.S. domestic natural gas production is only expected to increase by less than half of that amount over the same period.

The most dramatic growth in demand for natural gas is expected to be for electricity generation. Of the new electric generating power either recently constructed or about to placed in operation over the next few years, over 90% will be fueled by natural gas. Still, it is quite clear from EIA's analysis that the production necessary to match this demand is not there.

The supply imbalance we face has been years in the making. Quite simply, we have pursued a policy that is in conflict with itself. On the one hand we encourage the use of natural gas in this country to meet our energy needs and environmental goals. Natural gas is viewed as a clean burning fuel to improve air quality and a low carbon-dioxide fuel to meet climate change targets. However, we have ignored the supply side of the equation. We promote the use of natural gas but restrict its production. As is indicated in some of testimony today, the increasingly mature basins we have produced over the decades are "exhausted" and new prospects are either difficult to get to or off limits.

WHAT CAN BE DONE?

I believe there are a number of options available to us, none of which will singlehandedly solve the dilemma we face but all of which can contribute to improve the picture. Some of the ideas on the table should include:

- supporting efforts to incentivize the production of natural gas such as those in the Energy Conference Report like Section 29 tax credits that will tap "unconventional" gas reserves such as coalbed natural gas and issuing royalty relief for ultra deep wells drilled on existing leases in shallow waters. According to the Minerals Management Service (MMS), since much of the infrastructure in these areas is already in place, the new gas reserves could be brought into the market quite quickly. In fact MMS anticipates that deep well incentives could provide as much 55 tcf.
- taking advantage of the diversity of supply available in this country—Presently, over 70% of our electricity generation in this country comes from nuclear power and coal. While EIA anticipates in their 2004 report that coal use will increase, they do not appear as optimistic for nuclear energy. That fact is no nuclear plants have been built in this country in 25 years. We should take advantage of this power source that provides emission free electricity. To the credit of the Chairman of the Committee there are provisions in the Energy Conference Report that will encourage the production of a new generation of nuclear reactors

which can help our country meet its energy needs and environmental goals for years to come;

- establishing a national renewable portfolio standard (RPS) for electric utilities to encourage the production of renewable sources of energy (wind, solar, et al.) and lessen dependence on natural gas for electricity;
- OCS—Most of the Pacific Coast and Eastern Gulf of Mexico as well as the entire Atlantic Coast are off limits to exploration and production. Since this frontier was officially opened to significant oil and gas exploration in 1953, no single region has contributed as much to the nation's energy production as the OCS. The OCS accounts for more than 25% of our nation's natural gas and oil production. With annual returns to the federal government averaging between $4 to $5 billion annually, no single area has contributed as much to the federal treasury as the OCS. In fact, since 1953, the OCS has contributed $140 billion to the U.S. Treasury. In light of these tremendous contributions, it is particularly interesting to realize that almost all of our OCS production comes from a very concentrated area of the OCS, the western half, which really means offshore Louisiana and Texas. 98% of the nation's offshore production comes from this half of the Gulf of Mexico. In FY 2001, offshore Louisiana alone accounted for almost 80% of total OCS gas production. While it appears that the deeper and even ultra-deep waters of the Western and Central Gulf hold some promise we should establish what potential reserves may be in those areas under moratoria.
- LNG—Presently, LNG provides about 1% of U.S. gas demand but EIA estimates by 2025 LNG imports could increase to 15% of our consumption. There four operational LNG terminals in the continental U.S. right now including one in Lake Charles, Louisiana. As of December, 2003 there were 32 active proposals for new terminals. While I think everybody would concede that LNG will be a significant part of the natural gas equation in the future, there are some questions that need to be addressed. Do we want our gas market to follow in the steps of our oil market in 1970s where we rely increasingly on imports? Would we be setting ourselves up for exposure to possible insecure sources of foreign supply? Are world natural gas reserves sufficiently dispersed compared to those for oil (Middle East). According to Steve Brown, the Federal Reserve Bank of Dallas' lead energy economist, "LNG terminals are only attractive at very high prices." So, what happens to the investment in LNG if the price of gas drops. Presumably, the interest in building these facilities is in response to the rise in prices. What impact would a drop in price have on interest in LNG?

Senator LANDRIEU. Thank you.

I would like to focus my questions on, of course, the Gulf of Mexico, which is where Louisiana is squarely a leader. While I have supported, obviously, opening up other areas, Alaska, for natural gas, as well as I have supported the policies that would bring in liquified natural gas, I do have concerns about getting out of the fire into the frying pan with the same dependency outside our State. I would like to focus and just ask, a few questions about trying to clarify the amount of reserves in the Gulf of Mexico. There are three sections, eastern, central, and west.

Could you all just either restate for the record, because some of you touched on parts of this, or jump in and help us try to understand what the universe of reserves may, in fact, be based on your best estimates and guesses, either articles or studies that have been published or your professional judgment, to try to give us a more accurate sense of what may be recoverable in the different sections of the gulf that we have not tapped? Because to me the expertise is in the gulf. The political stability of the gulf, the trained work force that is in the gulf all lead to trying to promote production in the Gulf of Mexico.

Now, I understand about the Florida dilemma, but I do not want to get into that debate right now. I am just trying to understand. The Gulf is a big place. We have been drilling there now for almost 60 years successfully. Anadarko has several new—so breaking it down just as quickly as possible, eastern, central, and western, now that we can go almost 20,000 feet deep, not quite yet, but we are going 15,000 feet deep, which may open up most of the gulf all the way to Cancun and beyond, tell us what we found and what you think is still there. I do not know, Mr. Sharples, if you want to go. Just gas.

Mr. SHARPLES. I do not have numbers in front of me. We will research it and we will be happy to provide for the record, if we have internal estimates. I am not sure that we do.

But I will say that there are still interesting things to do in the Gulf of Mexico. I discussed the eastern gulf. It is at the very early stages of development. History tells us there will be more big discoveries there. You tend to find the biggest fields first.

Most recently the Eastern Fold Belt around our Marco Polo K2/K2 discovery, but a number of other discoveries by others is probably the most active area in the deep part of the Gulf of Mexico, very exciting discoveries. And some very interesting teasing, if you will, at very deep fusing levels where we are seeing people drill actually 30,000 feet, not 30,000 feet of water, but 30,000 foot total depth, water and well bore, with some potentially interesting discoveries. Very expensive initial dry hole cost to the tune of $50 million plus to drill an exploratory well. So it is still at the very early stages. It may or may not work economically.

All that said, history says that deep water development has not been able to overcome the declines in the shallow water shelves, and I do not think they will. But I think that there are tremendous to do.

Guy, do you have——

Senator LANDRIEU. Before you leave that point—and I would like Mr. Caruso—but are there new technologies that will help us to explore more fully on the shallow shelf, or is it just drilled out?

Mr. SHARPLES. As an explorationist, I would say that the jury is still out, in our opinion, on what is known as the deep shelf, drilling deeper wells in shallow water. There have been some very interesting discoveries and a lot of disappointment. That is an area that is receiving a lot of interest. I do not think it is a panacea, but I think we will make some interesting discoveries in the deep shelf.

Senator LANDRIEU. Mr. Caruso, could you give us any more specific numbers just to sort of lay it out for the committee? Because it is something that we are very interested in. There are sections of the gulf that we realize are under moratoria, but there are sections that are not. If in this bill we have some incentives for deep drilling, some incentives that are being discussed for additional research and development, given that we know we have to increase supply and it only is going to come from Alaska, the Rocky Mountains, or the Gulf of Mexico. If we want it to come domestically, I think we need to get clear about what the real potential is in the Gulf and act accordingly based on what is politically possible, scientifically sound, and environmentally responsible. So can you add any more of maybe particularly the central and western gulf, since that is not under moratoria?

Mr. CARUSO. We would be able to provide those numbers for the record.

[The information follows:]

POTENTIAL NATURAL GAS SUPPLY FROM THE GULF OF MEXICO

There are several indicators of the future potential for production from the Gulf of Mexico.

Production was over 4 Tcf and Proved Reserves were 25 Tcf for both the Western and Central Planning Areas combined in 2002. The Proved Reserves are reasonably certain to be produced in the future.

	Production (Tcf)	Reserves (Tcf)
Central Planning Area	3	19
Western Planning Area	11	16
Combined	14	25
U.S. Total	19	187

Future potential also includes natural gas resources that have yet to be discovered.

According to the MMS 2000 National Assessment, the mean estimate of "Undiscovered Conventionally Recoverable Resources" for the Western Planning Area is 74.7 Tcf. For the Central Planning Area, the mean estimate is 105.5 Tcf. The Total is 180.2 Tcf.

These 180 Tcf of technical recoverable resources represent a potential future supply roughly equivalent to the 187 Tcf of U.S. Proved Reserves of Dry Natural Gas in 2002. It will be decades before the majority of this estimated undiscovered resource is discovered and developed.

Mr. CARUSO. To the general point, we would agree we are resource optimists when it comes to the availability of additional resources and reserves to be added to our supply system from the gulf. And our forecast does have increases in the deep water gas, although it has been a little bit less optimistic as the drilling results come in, but still it is growing.

The other area is shallow water deep gas that the MMS has recently revised upward its resource estimates for that component of the gulf.

So we think there is considerably more gas to be developed although we are running harder just to keep up with the decline rate particularly in that region.

Senator LANDRIEU. I know my time is short, but I would like just the courtesy of just one more question particularly to Anadarko.

Senator CRAIG. One more, Senator, and then we will do another round if you wish.

Senator LANDRIEU. OK.

We not only want to try to help you get gas out of the shelf and off the coast—and we do it, we think, almost better than anybody, Texas and Louisiana, Alabama, Mississippi to a certain degree. But Louisiana and Texas have developed quite an expertise and we are proud of the expertise we have developed. We would like to help the country get a greater supply.

One of the issues that has been brought to my attention that recently some of our yards—I know this is a little off the subject, but they have been unable to either compete to build the construction and the platforms necessary because of a number of things, the price of steel based on some decisions that have been recently made, and the lack of depth in some of our ports because the equipment now and the platforms are so large and so huge, that some of this is actually being constructed over seas and floated in.

Can you comment just briefly? Because, Mr. Chairman, talk about adding salt to the wound. We are trying to help get gas out of the gulf, one of the few places in the country that is not just promoting it but welcoming it and urging it. And now we see, in some instances, some of the actual jobs being sent overseas and we do not even get the benefit of the tax dollars. So we are just in a place where we are just not sure what next step to take.

I do not want to put the company on the spot. I know you all make these decisions based on your bottom line. But is that what you see happening?

Mr. SHARPLES. To some extent, it certainly is. There are some things we cannot get around, like the depth of the water in the port to physically float the facility out.

I think a best example is we had recently launched and installed a deep water facility. The hull, the underwater part was actually constructed in South Korea, but the entire top sides, all the work, all of the pipe fitting, all of the equipment was actually constructed in Texas and built in Texas, and they were brought offshore and put together.

We need, as an industry, to utilize all the available capacity, and we just need to make sure that we do that.

Senator LANDRIEU. But I want to know what Mr. Sharples said in conclusion to this committee, because the Senator from Tennessee and Alaska and Idaho have been so sympathetic and supportive, I want to make this point. The gentleman said the company is not responsible for the depths of the channels, and he is correct. But the Government of the United States is responsible for the depths of the channels. We have a policy where we are taking oil and gas off the shore of a State, but the people of that State cannot work on the facility because this Government refuses to take a few pennies—pennies—generated by the taxes and keep those channels dredged so that American workers can do the work.

So this is an issue, I just want to tell you, I am going to bring to this committee. It is not the companies' fault, but it most certainly does not seem like good policy when we are looking for jobs, looking for gas. We have got people who can do the work and have the gas and cannot keep it in Louisiana, Texas, and Mississippi, or Alabama.

So that is all I will say. Thank you.

Senator CRAIG. Thank you, Senator. Dredging is a problem. It took an environmental statement 5 years to clear in the lower Columbia River because of environmental law and concerns as to where you put the tailings. So there are a lot of complications out there that embroil us.

Senator LANDRIEU. This was not environmental. It was funding. It was not environmental.

Senator CRAIG. It was funding only. Well, I know there is a balancing there of combination. I agree with you. Resources are clearly necessary for that dredging purpose.

Let me ask a question. I will move to our other colleagues.

Mr. Caruso, let me read this first. Canadian Gas Production Outlook Week. This is yesterday. Exports of natural gas from Canada to the United States fell 1.5 bcfd through the first 10 months of 2003, according to data from the National Energy Board, and was down to 8.999 billion cubic feet a day in October. The outlook for Canada's supplies is continually decreasing in 2004 and 2005 according to Consult Global Insight. Trans-Canada Corporation expects a .5 bcfd lower western Canadian production next year while the National Energy Board also expects decreases so quoted.

Now, the reason I put that up probably becomes quickly obvious to you. I am aware that EIA, prior to last November, projected gas from imports from Canada increasing over the next several years, and since November, of course, they projected a flattening of gas exports to the United States.

This, at least to me, was a surprise. Was that large decrease a surprise to EIA and do these figures change your confidence in EIA's projections made last year about Canada's ability to sustain the export volume that Americans have become accustomed to?

Mr. CARUSO. Yes, sir. In fact, that was one of the major changes we made in the Annual Energy Outlook this year, to reassess the Canadian resource base and their ability to continue to increase production.

Senator CRAIG. How did you miss it? Or what happened?

Mr. CARUSO. We were much more optimistic about their ability to produce gas from coalbed methane and tight sands. Results have been much more pessimistic than we had thought. So we have revised downward our assessment of what Canada can produce and particularly what they can export. We now have an actual decline in Canadian natural gas exports to the United States over the next 2 decades.

Senator CRAIG. I had the Energy Minister from Canada in my office yesterday. We were visiting, and I am looking at all their new figures of ebb and flow, not just in gas and oil but also in electricity.

I know that creating an integrated North American energy market was a key recommendation of the President's National Energy Policy, and I am familiar with the efforts of Secretary Abraham to form the North American Energy Working Group. But I worry about our ability to accurately project exports from our neighbors. We rely quite heavily on Canada for natural gas and electricity.

Has the working group developed a process by which EIA can assure that Canadian projections and U.S. projections are in sync given our rather heavy dependence on our resource-rich neighbor to the north? I am especially interested in EIA's understanding of the Canadian demand, supply, and delivery dynamics so that I can have a more complete picture. I think that all of us can have a more complete picture on these critical issues. They impact us.

Mr. CARUSO. Yes, sir. EIA is participating in the North American Energy Working Group. It is chaired on the U.S. side by the Assistant Secretary for Policy and International Affairs in DOE. But we are, in effect, their analytical arm in supporting this group and we work closely with the National Energy Board and the appropriate ministries within both Canada and Mexico.

Certainly the National Energy Board report of July of last year was instrumental in changing our view of Canada's ability to deliver in terms of productive capacity.

Senator CRAIG. Since we are talking about reducing gas demand, is it correct that a recent tax analysis by EIA found a 3 percent reduction in gas demand and price with the addition of the 6,000 megawatts of nuclear power potentially projected in the energy policy?

Mr. CARUSO. Yes, in the Service Report we did for Senator Sununu of the Conference Energy Bill, which has now changed.

Senator CRAIG. That was a product I think of Senator Sununu requesting an analysis.

Mr. CARUSO. Exactly. There was a tax credit for advanced nuclear capacity. It would have added 6 gigawatts of additional nuclear capacity, as well as some additional integrated gasification combined cycle for coal, adding 22 gigawatts over the next 20 years. And that would reduce the amount of gas if those tax credits were to become law.

So, yes, there would be a reduction. I will supply for the record the actual percentage.

[The information follows:]

A recent Energy Information Administration analysis found a 3 percent reduction in natural gas wellhead prices and natural gas consumption by power generators in 2020 due to the nuclear production tax credit (NPTC) provision in the Conference Energy Bill. Total natural gas consumption in 2020 was reduced by 1 percent. However, by 2025, natural gas use in the power sector is only 2 percent lower than in the reference case because the NPTC is not expected to induce additional new nuclear capacity beyond the 6,000 megawatts for which it is provided, while electricity demand continues to grow. Impacts on natural gas prices also vary over time. For example, natural gas wellhead prices in 2025 are projected to be slightly higher than in the reference case because lower natural gas prices in prior years are projected to delay the second phase of the Alaska natural gas pipeline to beyond 2025.

Senator CRAIG. That would be appreciated. Thank you very much.

Let me turn now to my colleague from Alaska, Senator Murkowski.

Senator MURKOWSKI. Thank you, Mr. Chairman.

Welcome, gentlemen. I am sorry that I was not able to hear your presentation this morning. I have had the opportunity to read through all of the testimony that was presented prior to the hearing this morning.

I appreciate the fact that Alaska is recognized and contained within the solution when we are talking about meeting this country's demand for natural gas. We recognize that in Alaska we have got what the country needs. We just need to figure out how to get it to you.

I always like to listen to my colleague from Louisiana. She and I share a great deal in common when it comes to energy issues. To hear her frustration over government policies inhibiting our activities or our ability to get the much-needed energy to Americans, it is a subject that we can entirely relate on.

I do note, Mr. Caruso, in your statement that the assumption is that the Alaska natural gas pipeline will come on in the year 2018 or thereabouts. We in Alaska want to do all that we can to see that happen earlier. As you know, there have been several applications submitted to the State, one from the three major producers, one from Mid-America that was referenced by the Senator earlier, and there was a third application that was just submitted last week that relates to what we call the All Alaska LNG Line, which would be a spur line running down through the State of Alaska—liquified natural gas for transport to the west coast.

This is something that has not been included in anybody's analysis, so far as I can see. It is something that we have been focused on in Alaska for some time. We want to make sure that not only do we get our natural gas to the markets in the Lower 48, but we also want to make sure that Alaskans have access to our own gas as well. So this is a project that we are following very, very closely.

So a question to probably you, Mr. Koonce, because you mention in your testimony the two applications that are pending and recognize that with these applications, there is a promise to result in a project that is more innovative and less costly than many previously thought. We hope that you are right, that there will be that competition, there will be that incentive to move something along.

First, a question to you as it relates to the possibility of an All Alaska Line or a spur and then how that might affect your analysis of getting gas to market through the pipeline across Canada or possibly LNG imports from Alaska. Have you looked at this project at all and would you like to share any comments?

Mr. KOONCE. Senator, I apologize. I have not. I am not acquainted with the LNG alternative that you speak of. But as an industry and as a company that participates in pipeline development, we are very anxious to see if we can move along the development of this pipeline and the resource base more quickly than 2018. It is our belief that it is needed more quickly than that when you look at the domestic decline.

In my discussions with individuals from Trans-Canada, as well as Mid-America, and as a company that is in the local distribution business—we serve retail customers in Ohio and Pennsylvania and West Virginia—it is very important that the infrastructure be in place. But what is more important is there be supply contracts to back-stop the capacity.

In my discussions with Trans-Canada and others about the likelihood of that project moving forward, what I tell them, sitting in the eastern half of the United States, what is most important is the project developers bring with them representatives of the producing companies who can make representations to fill that capacity with production. That really is what we are anxious to try to bring about because I think once local distribution companies sign up for capacity, they also want to know that there is supply that they can count on. They do not want to make one without the other. I think that is the area where probably the most work needs to be done, now that we have two competing proposals attempting to get this gas out of Alaska.

Senator MURKOWSKI. I want to make sure that we state clearly for the record—I have said it repeatedly to my colleagues, but it bears repeating here—that in order to facilitate an Alaska natural gas pipeline, we have got to get the energy bill through or certainly those components that allow for a natural gas pipeline, whether it is the permitting and streamlined regulatory review, certainly the financial incentives. All of these will be key. If we fail to do that, I am concerned that when we look at this chart that shows the growth in Alaska production, that that is pushed out even further.

Based on all of the analyses that I have seen, we as a country cannot afford to push that curve out further because what happens is we increase our reliance on foreign imported LNG. Quite honestly, looking at the figures, recognizing that right now we import 1 percent of our LNG, but by the year—what is it—2025 we will be at a point where we are importing 15 percent LNG, that is a dramatic increase in a relatively short period of time.

Of course, the concern that I think we all share is that we get to that point with our natural gas that we currently are at with our oil where we are close to 60 percent dependent on foreign sources of oil. We do not want to go there with our natural gas when we have the reserves in this country. We might not be able to do 100 percent of it, but shame on us if we get to the point with natural gas that we are with oil.

So I appreciate again the focus on Alaska, and I would ask all of you to help us educate the rest of the country on the need to bring Alaska's gas to market.

Thank you, Mr. Chairman.

Senator CRAIG. Thank you, Senator.

Senator Alexander, questions?

Senator ALEXANDER. Thanks, Mr. Chairman. I agree with what Senator Murkowski had to say. The natural gas pipeline is not just an Alaskan concern, it is an American concern so far as I believe.

I just have a single question. I am trying to understand LNG and what the cost of it will be, how reliable it will be if we are looking ahead 10, 20 years, what it will do to the cost structure of natural gas in this country.

This afternoon I am chairing a hearing in the Energy Subcommittee on the future of nuclear power, and that reminded me that 90 percent of our new power plants have been natural gas. Given the skyrocketing price of that and the uncertainty of LNG, I just wonder what we can expect. I hear from some quarters that there is plenty of gas around the world. It can be put in LNG. It can come here. It can bring our price back down to $2 to $3. Everything is going to be fine for 10 or 20 years. I hear concerns on the other side. It makes a difference in this country in terms of jobs. It makes a difference in terms of clean air whether these projections are right.

So what about LNG? What will be its cost delivered? What will it do to our long-range cost structure and what is the reliability of it as a source of supply?

Mr. KOONCE. Senator, I would be happy to start the answer. I am sure others have more to add.

We are very encouraged by what we see taking place on the natural gas/LNG front. The FERC about a year and a half ago adopted what is now called the Hackberry doctrine, which is a policy that we would like to see become law. The brunt of that policy is one where two parties can negotiate for the capacity of a gas import facility. Right now, Federal regulations require that under open access everybody have an opportunity to participate in a project. What that has the effect of doing is frustrating upstream development of infrastructure. And our company just announced a major expansion of our——

Senator ALEXANDER. Are you talking about a terminal?

Mr. KOONCE. Yes, sir. What it does with the Hackberry doctrine, it allows an upstream developer to know with certainty that they have a place that they can make redelivery of their LNG import capacity. So with the Hackberry doctrine now hopefully becoming law, those companies that have reserves around the world can now reliably negotiate for re-gas facilities in the United States with certainty so that they can make the upstream investments in order to bring natural gas supply on line and make the investment in ships.

Right now the landed cost of natural gas in the United States is competitive down to $3 for existing facilities and maybe even lower. New facilities going forward with the technology improvements, with the scale that can come with the upstream liquefaction, with 200,000 cubic meter ships, we believe that new sources of LNG will continue to be competitive at or below $5.

So what we hope to see is that on the U.S. side we adopt policy that allows clear negotiating authority for two companies to agree to work exclusively with each other to develop the re-gas facilities which will allow them then to make the commitment upstream.

Senator ALEXANDER. Just so I understand you, if I am a businessman and I am planning ahead and I am planning to use a lot of LNG, I better plan on a $5 price?

Mr. KOONCE. We think new sources of LNG can be competitive below $5. We think that it will serve to be a——

Senator ALEXANDER. You mean an LNG company can make money at $5?

Mr. KOONCE. At below $5.

Senator ALEXANDER. Anything below $5.

Mr. KOONCE. Yes, sir.

Senator ALEXANDER. What if I am on other end of it? I am a consumer. What would you recommend I put in my plans for the next 10 years? What range?

Mr. KOONCE. Well, again, I would say that the EIA range of prices being plus or minus $5, trending down as more facilities come on stream, I think is a good way to think about that question so long as we get clear siting authority and we can get the new facilities in place without delay.

Senator ALEXANDER. Thank you.

Mr. SHARPLES. If I may add just a couple of points. I do not disagree with the estimate of price.

But I think that a lot of the analysis that you read, which is essentially a cost-based analysis that says, well, ships cost this much and re-gas costs this much, and therefore, gas ought to cost this much, really miss some very significant points, the first of which is LNG is a world market. The United States is not the only market for LNG. It is not "build it and they will come." During some of our highest price levels in the last 3 years, we have had existing import facilities that sat unused because other markets in the world demanded that gas and were willing to pay a higher price. Point number one.

Point number two is that the upstream LNG projects need to compete for capital with other opportunities for the oil and gas companies around the world. Right now we are riding a wave of some gas that needs to find a home. It was found in association with oil in places like offshore West Africa. It needs to come somewhere. When that is used up, and we have to incent brand new LNG projects around the world, LNG gas supply projects to feed all of these terminals, the price that is received has to be high enough to incent the huge capital projects.

So it is not a panacea I guess is my only point. I think the ranges that, Senator, you mentioned where we grow to about 15 percent of total supply is probably doable. I would not say that you could go significantly above that or that we could do it at prices significantly below the ranges that Mr. Koonce just mentioned.

Senator ALEXANDER. Thank you. Thank you, Mr. Chairman.

Senator CRAIG. In the context of the dialog that you have carried on with Senator Alexander, and especially to you, Mr. Koonce, in your testimony you state that Congress may need to further clarify Federal supremacy in the approval and siting of pipeline and LNG terminals to be used in interstate and foreign commerce.

What is your assessment of the situation regarding the LNG proposal by Mitsubishi in Long Beach, California and the jurisdiction turf war taking place between California PUC and the FERC?

Mr. KOONCE. Yes, Senator. I am very troubled by it. I see it heading down a path that could delay the import of LNG into critical markets almost indefinitely. We need to make clear—and I really think it is important for all the constituents that participate in this process, be it consumer advocates, be it landowners, be it environmentalists, or project developers. What is lacking today and what we must do is create a clear pathway for these alternatives to be debated, and we need to create one platform where all those constituencies can know to go to make the record so that the agency charged with that responsibility can discharge its responsibilities even if that means a no-siting decision so that the industry can move to the alternate sites that may be next in the queue.

So when we look at whether it is the Coastal Zone Management, one Federal set of regulations versus another a Federal set of regulations, or whether we look at State versus Federal, what is troubling is the level of continued prosecution of these projects that do not seem to ever get to an end. And for a company that is using shareholder capital to develop those projects, we now get much more careful about which projects we attempt to pursue because of the potential do loop you can get into.

Again, I think it is just as important for all the constituents who have limited resources, in terms of financing, to tell them once and for all where they need to go to make that case. I think it is very troubling.

Senator CRAIG. Thank you very much.

Before I turn to Senator Schumer, one last observation, Mr. Sharples. I agree. I do not think LNG is a panacea and I say that because we are not the only ones after it and you have said that. I was in Europe recently during the climate change conference in Milan and visited with Italian producers and distributors, and it is true of Germans and all of Europe is looking at gas. Their projections of use of gas are almost straight up. Of course, obviously, for the same reason it is happening here in part. And they are looking at a lot of potential and pipeline development coming out of the Caspian and all that, but it is out there in the future.

They also know that the likelihood of maybe less disturbed and more reliable could be LNG in some instances versus the political consequences of a Caspian basin development or even something more coming out of Russia.

So it is potentially a very competitive market. Depending on its rate of development, its rate of capitalization, I think I agree with those observations. Do you disagree with that?

Mr. SHARPLES. Not at all, Senator.

Senator CRAIG. Let me turn to the Senator from New York, Senator Schumer.

Senator SCHUMER. Thank you, Mr. Chairman. I appreciate the panel.

My first question, first, I would like Mr. Caruso to talk about it and anybody else. This relates to the oxygenate requirement that is currently forcing California, New York, and other States to use ethanol in the gasoline. As the summer blend requirements come on line and base gasoline will need to be blended to have a lower RBOB, does EIA still believe, as you stated in the October report, that supply mismatches could result in extreme price spikes? Has the oxygenate requirement created a situation in which New York is an unattractive niche market for external gasoline suppliers?

Mr. CARUSO. Thank you, Senator. We have been watching the MTBE ban development, of course, in California last year, and New York and Connecticut as of 1 January this year.

The results so far have been relatively smooth in the winter, as you mentioned.

Our concern, as we mentioned in October and continue to be concerned about as we go into this summer, is whether or not opportunistic suppliers of RBOB will be available to meet the full demands. And we still do not know the answer to that question. So the potential for price volatility continues to exist, and I think we will have some early hints even beginning this month.

Senator SCHUMER. As you know, I have been pushing the administration. Governor Pataki has asked for an elimination or a waiver of the oxygenate requirement. They gave one to New Hampshire, a little different than New York. But what you are saying is the possibility of significant price spikes like we saw in California is very real. You are not sure it will happen, but it could?

Mr. CARUSO. Is it possible? Yes, sir.

Senator SCHUMER. A broader question on gasoline. First, Mr. Caruso and then anyone else can answer it. Given the fact that the severe cold experienced by much of the country this winter has led to a longer period of heating oil production than normal, the fact that winter gasoline demand has been above average, and crude oil stocks are at their lowest since 1975, will U.S. refiners be able to physically meet the demand for gasoline heading into the summer months? It is a more general national question.

Mr. CARUSO. Our short-term outlook answer to that question is that we will need substantial imports, particularly from Europe, to meet the summer gasoline demand, but I think there are a few things that make it a little less certain this summer than previously, and that is, Europe itself is operating at fairly high rates of utilization and freight rates are up which tend to cause them to keep the product home.

Senator SCHUMER. Are you saying it is possible that the national average which is now what? Getting close to $1.80, is it?

Mr. CARUSO. It is $1.72 this week.

Senator SCHUMER. Could it get as high as $2 or no?

Mr. CARUSO. I do not know the answer to that for sure.

Senator SCHUMER. It is above $2 in, I think, California right now.

Mr. CARUSO. Yes. It is $2.10 in California this week. But we will be looking at that more closely when we do our next outlook. I think we will be raising our previous expectation which was then a peak of $1.69. We have already exceeded that.

Senator SCHUMER. That is a pretty good bet you will raise it.

[Laughter.]

Mr. CARUSO. A key factor is where we think crude markets are going, and earlier we discussed the current price of WTI at about $36. But we do think that will, on average, come down. Depending on the exact timing of that, it will make a big difference in whether we will get much above the $1.72. Certainly the risk is there. I think, as I mentioned earlier, there is an asymmetrical risk of a higher price and a higher volatility this summer given the tightness in gasoline.

Senator SCHUMER. Does anyone else want to comment on that?

Mr. SAUNDERS. If I could add real quickly on that, if you do not mind, Senator.

Senator CRAIG. Mr. Saunders has made comment on that. If you would respond.

Mr. SAUNDERS. Just to reiterate what Mr. Caruso said on the imports, we are already seeing very low levels come out Venezuela, which supplies about 10 percent of U.S. gasoline imports, as well as the rest of South America on this low sulfur spec. So if you run some rudimentary numbers and if you put a 10 percent, say, decline in imports relative to last year and if you get a percent and a half of demand growth and if your yields are a normal level for this time of year, you are still about 5 million barrels or so in inventory lower than you were last year. Remember, the prices spiked at this time last year, and the only reason they came down was that demand was—it took a relatively long time in coming through because we had a lot of wet weather in the spring last year.

Senator SCHUMER. So where does that lead the price in terms of the practical question that I get asked all the time?

Mr. SAUNDERS. It is largely a question of the crude price, which I think is going to come down, but I think it is going to be a very high gasoline price season.

Senator SCHUMER. Would you want to take a stab at what you think the average will be?

Mr. SAUNDERS. These guys are much more familiar on the retail side than I am. But if you say crude is going to stay up at $34 or $35, I see no reason to think east of California that you will not be above $1.75 or $1.80.

Senator SCHUMER. Thank you.

Does anyone else want to comment on that?

[No response.]

Senator SCHUMER. All right. The final question, because I know my time has expired.

Senator CRAIG. Yes, if you could do that. We need to be out of here by 12, and I am sitting here contemplating Chuck Schumer on a bicycle all summer.

[Laughter.]

Senator SCHUMER. I ride a bicycle when I am in New York.

Senator CRAIG. A fascinating idea, especially right down through the middle of New York City. Anyway, excuse me. Go right ahead.

Senator SCHUMER. Mr. Chairman, in deference to that, I will submit written questions. Thank you.

Senator CRAIG. I did not mean to scare you off.

Senator SCHUMER. No, no, no. You sometimes do, but this was not one of those times.

[Laughter.]

Senator CRAIG. No loaded guns.

Anyway, gentlemen, thank you very much for your presence here this morning, your testimony, and your timeliness to our concerns. As you know, as we try to seek out the future of energy supply in this country and the process by which we get there, accuracy in reporting and projecting, while I know it is not an exact science, the closer we can get to it, the better we will all be in the shaping of policy. I appreciate it.

The committee will stand adjourned.

[Whereupon, at 11:58 a.m., the hearing was adjourned.]

APPENDIX

RESPONSES TO ADDITIONAL QUESTIONS

DEPARTMENT OF ENERGY,
CONGRESSIONAL AND INTERGOVERNMENTAL AFFAIRS,
Washington, DC, April 20, 2004.

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

DEAR MR. CHAIRMAN: On March 4, 2004, Guy F. Caruso, Administrator, Energy Information Administration, testified regarding energy supply forecasts.

Enclosed are the answers to 18 questions submitted by Senators Campbell, Bingaman, Feinstein and You. The remaining answers are being prepared and will be forwarded to you as soon as possible.

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

Sincerely,

RICK A. DEARBORN,
Assistant Secretary.

[Enclosures.]

QUESTIONS FROM SENATOR DOMENICI

Question 1. Some have called for the elimination of all dependence on foreign oil by 2020. Is that economically feasible? What resources could the U.S. realistically rely on to fulfill our energy needs if such an agenda was undertaken?

Answer. Reducing the estimated 17.5 million barrels a day of crude and product imports projected in 2020 to zero would not be achievable under any plausible scenario. Additional access to the Alaska National Wildlife Refuge could reduce imports by an average of 900,000 barrels a day[1] Alternative transportation fuels cannot be expected to completely displace foreign oil by 2020 because many of the resources that could be realistically relied upon are already facing increasing demand pressures, which will limit their availability to provide significant volumes of fuel. These include most of the technologies used to create synthetic petroleum from coal, natural gas, or agricultural products (ethanol/biodiesel).

Natural gas and coal-based synthetic gas face increasing use by electricity generators and the cost to produce these fuels is not competitive with projected long-term world oil prices. Fuels based on agricultural products are also not cost competitive with oil now and face increasing upward price pressure from the entry of China and India into U.S. grain markets. Coal to methanol, while economically practical, has air toxics issues and groundwater pollution problems similar to methyl tertiary butyl ether. It is unlikely that hydrogen could make any meaningful entry as a transportation fuel before 2020 due to the current extremely high cost of the vehicles and the cost to distribute the fuel. Transportation technologies that burn petroleum more efficiently (hybrids/light duty diesels/high MPG engine designs) will provide some reductions in import demand but are unlikely to provide any major reductions without significant regulatory changes.

Question 2. Can you describe the general fuel switching abilities in the U.S. market between oil and natural gas? What barriers exist to fuel switching?

Answer. Fuel demand includes a portion with some fuel-switching ability. Focusing on natural gas, there is no single figure for the consuming potential attributable to fuel switching, because it differs among the alternate fuels. Estimates of switch-

[1] Energy Information Administration, "Accelerated Depletion: Assessing Its Impacts on Domestic Oil and Natural Gas Prices and Production," EIA-SR/OIAF/2000-04, (Washington DC, July 2000)

ing capacity by fuel can range widely. One recent study provided an estimate of switching capacity between natural gas and residual fuel by the industrial sector of about 0.2 billion cubic feet per day (Bcf/d), which is the equivalent of roughly 30,000 barrels per day of residual fuel (“Facing the Music: U.S. Industrial Gas Demand in an Era of High Gas Prices,” CERA Advisory Service). An EIA publication, U.S. Natural Gas Markets. Recent Trends and Prospects for the Future (May 2001), provided an estimate for switching between natural gas and distillate fuel of roughly 0.58 Bcf/d for commercial and industrial consumers. This is the energy equivalent of 102,000 barrels per day of distillate fuel oil.

There are a number of factors that can limit the ability of consumers to switch between fuels.

- The dominant factor is the size of the dual-fired capacity, which itself may not be fully available for switching at any given point.
- For any estimate of actual capacity, the amount of effective capacity will be lessened by its current utilization rate—i.e., if dual-fired capacity already has been directed to a lower-cost fuel, that portion of capacity cannot respond to further price movement.
- The ability to switch also depends on the availability of the alternate fuel. This may depend on inventories of the other fuel either on-site or with regional suppliers. Additionally, delivery capacity of the other fuel may be limited—e.g., transmission capacity may not be available to deliver natural gas for potential customers willing to switch from fuel oil.
- Environmental restrictions may limit or disallow the use of certain fuels. This may be more relevant at certain times of the year, for example, toward the end of the calendar year when a company may not have any remaining emissions credits to use and must burn natural gas.
- For any company, the willingness to switch will be mitigated by the switchover costs including any downtime of the equipment, and the expectation for relative prices.

Question 3. Oil reserve calculations have been in the news lately. In January, Shell announced a 20% cut in its energy reserves and El Paso slashed reserves by 40%. Please give us a brief explanation of what these cuts actually mean and whether they have made much of an impact on world oil prices.

Answer. EIA does not think that the Shell and El Paso reserve cuts made much of an impact on world oil prices, although it had a big impact on the stock prices of those companies. The cuts represent only a small fraction of the world's proved oil reserves. Proved reserves have to meet specific technical, economic and regulatory criteria. The Shell actions represent changing the classification of several fields proved reserves to a different category that has a lower probability of being produced. However, the oil and gas resources involved are still there and are technically and economically recoverable. Shell had not and has not made the financial commitment to build the necessary infrastructure to produce these resources. They should have made such financial commitments before they booked the resources as proved reserves. The negative revisions in El Paso's proved reserves were in much larger part, do to poorer than expected performance of producing wells in some of their larger fields. This is not uncommon for any one company. However, for all U.S. oil fields the annual sum of positive and negative revisions to proved reserves is usually positive.

Question 4. The EIA estimates project that net petroleum imports are expected to account for 70 percent of demand, up from 50 percent in 2002. Further, your studies show that OPEC provides about a quarter of our domestic petroleum needs. OPEC recently announced production cuts that seem to be holding prices at the high end, if not above, their own stated preferred price band of $22-28 per barrel target. In fact, the International Energy Agency Chief Claude Mandil [pronounced Mahn-deel] just stated on Monday, March 1, that, “it is clear that the price band is over.”

Question 4a. Do you agree that the $22-28 OPEC price band is over?

Answer. The Organization of Petroleum Exporting Countries (OPEC) basket price was above the price band for almost half of 2003, and has been above it every day but two (when it fell to $27.98 per barrel and $27.92 per barrel, just pennies below the upper end of the price band) since November 6, 2003. And yet, both times OPEC has met since November 6, 2003, on December 4 and February 10, OPEC surprised market analysts with their actions that supported higher prices. First, on December 4, 2003, when most analysts expected an increase in production quotas, OPEC stated their intention to keep production quotas unchanged. Then, when they met on February 10, 2004, OPEC once again surprised the market by announcing a production quota cut of 1 million barrels per day effective April 1. OPEC met again on

March 31, 2003 and reaffirmed that decision. Looking at these two most recent cuts as evidence, a case can certainly be made that OPEC is interested in prices remaining above their price band, making it essentially moot. OPEC production routinely exceeds its quotas, and when quota cuts are made, actual output often drops by a lesser amount.

Question 4b. Do you think that the root of current oil price volatility can be traced to OPEC cuts?

Answer. With most, if not all, of the world's excess production capacity, OPEC has the ability to lower crude oil prices by making more crude oil available at lower prices. OPEC has often stated that oil companies are not asking for more crude oil, but that is because the price at which OPEC is offering the oil is too high to make it economical for oil companies to purchase, unless they plan on refining it almost immediately. With oil prices at very high levels (Petroleum Argus, in their Global Markets publication dated March 29, 2004, stated that this is the first time prices for West Texas intermediate (WTI) crude oil have been continuously over $30 per barrel for four consecutive months since 1983), oil companies are not inclined to purchase excess crude oil to be placed in storage, fearing that prices are bound to come down from these high prices. However, by doing so, inventories remain at very low levels, especially if looked at from a days supply basis, leaving the oil market with little, if any, flexibility to respond to supply problems or demand surges. If, instead, OPEC was to make more oil available at prices low enough to create an economic incentive for companies to purchase it, oil prices would likely drop and remain below current levels. Therefore, whether or not OPEC is the root cause of high oil prices, OPEC does have the ability to lower prices.

Question 5. In his testimony in July 2003, Chairman Greenspan noted that "perceived tightening of long-term demand supply balances is beginning to price some industrial demand out of the market." How much demand destruction caused by high natural gas prices is permanent?

Answer. Current data do not provide a precise figure on the amount of natural gas demand lost on a permanent basis. However, industrial consumption, which is the largest consuming sector for natural gas, is dominated by a few industries, such as chemicals including ammonia for nitrogenous fertilizers, and pulp and paper. Information regarding these key industries can provide a rough estimate of the impact of higher natural gas prices.

Altogether, chemicals production accounts for roughly 7.2 billion cubic feet per day (Bcf/d) of natural gas consumption. Ammonia production requires an estimated 1.1 Bcf/d of the total consumption for chemicals. The Fertilizer Institute estimates that high natural gas prices have led to the permanent closure of 20 percent of U.S. nitrogen fertilizer capacity and the idling of an additional 25 percent of the remaining capacity. Absent economic relief, roughly 40 percent of U.S. capacity present in the 1999-2000 crop year is in danger of being shut down permanently. Regarding petrochemicals, the *Washington Post* reported on March 17, 2004, that one in every ten chemical-related jobs has been lost in the past five years. The Petrochemical and Refiners Association (NPRA) states that the U.S. balance of payments for chemicals went from an $8 billion surplus in 1999 to an estimated $9 billion deficit for 2003. Natural gas is used as a feedstock in both fertilizer and petrochemical production, which makes fuel costs a significant portion of total costs and does not allow for switching to other fuels.

Pulp and paper production accounted for an estimated 1.6 Bcf/d of natural gas consumption in 1998 (latest year for detailed data). Over the years, this industry has reduced its energy intensity in production and instituted other enhancements such as use of wood wastes and by-products to meet over half their energy needs. Nonetheless, 40 mills were permanently closed in 2001 and 2002. There is anecdotal evidence of further curtailments and shutdowns in 2003. It is not clear how much pulp and paper capacity or the chemicals capacity would be bought back on line if natural gas prices were to drop significantly and for an extended period of time.

Question 6. What are the inflation-adjusted prices for crude oil and natural gas compared to prices 20 years ago?

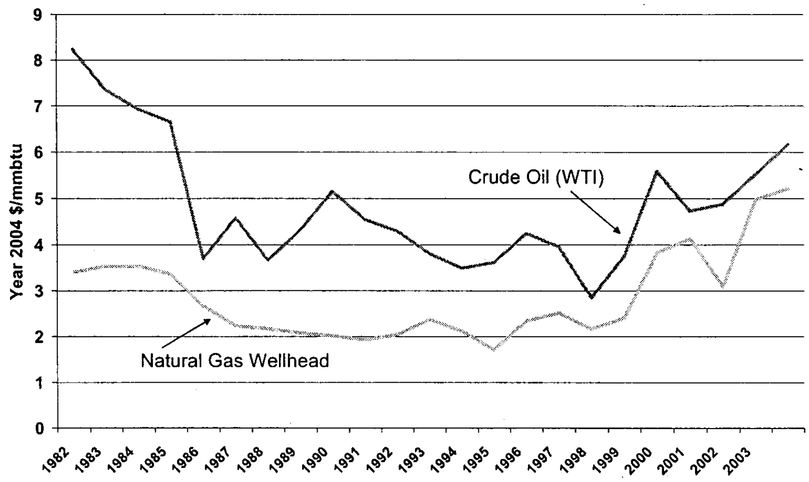
Answer. The inflation adjusted price for crude oil (West Texas Intermediate—WTI) was higher 20 years ago than the price today. (Here we use the Producer Price Index to deflate nominal prices.) Expressed in 2004 dollars, the price of WTI averaged nearly $48 per barrel in 1982, $43 in 1983, $40 in 1984, and $38.50 in 1986. During the period from 1986 through 2003, the inflation adjusted price for WTI was as low as $16.50 per barrel (1998) and as high as $32 per barrel (2000 and 2003). The WTI spot price on April 1, 2004 was $34.50 per barrel.

Unlike crude oil prices, natural gas wellhead prices are at their highest inflation-adjusted level in over 20 years. From 1982 through 1985 the average annual wellhead price for natural gas (expressed in 2004 dollars), was about $3.50 per thousand cubic feet. During the period from 1986 through 2003, the inflation-adjusted wellhead price, on an annual basis, was as low as $1.76 per thousand cubic feet in 1995 and as high as $4.25 in 2001. In 2003, the annual average wellhead price for gas averaged $5.10 per thousand cubic feet. The most current spot price for natural gas (Henry Hub on April 1, 2004) was $5.99 per thousand cubic feet.

The chart below illustrates the paths for real oil and gas prices on a consistent ($/million Btu) basis:

Inflation Adjusted Crude Oil and Natural Gas Prices

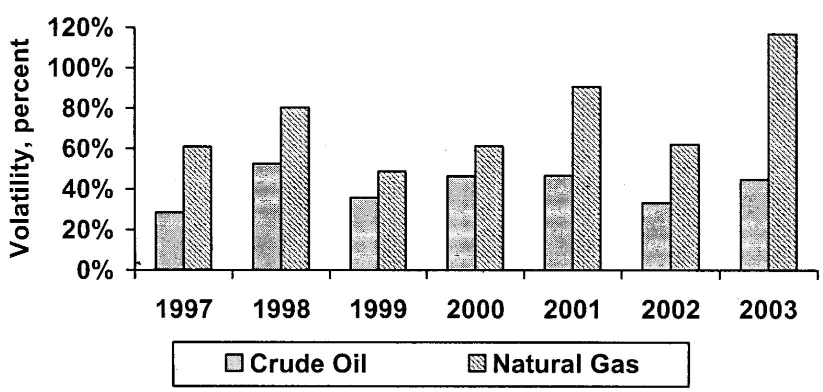
Annual Average: 1982-2003



Question 7. Are natural gas prices more volatile than oil prices and why?

Answer. Price volatility generates significant uncertainties in energy markets. Annual price volatility is calculated from daily spot prices using the formula, {var [ln(P2/P,)] × number of observation} ½. Figure 1 shows that over at least the last seven years the spot price of natural gas has been more volatile than that of crude oil.

Figure 1. Crude Oil and Natural Gas Price Volatility



Crude oil: WTI spot price at Cushing, OK
Natural gas: spot price Henry Hub, LA.

There are a number of causes of price volatility in energy markets such as daily price responses to market news, short-term supply disruptions or demand shocks, longer-term business cycles that exhibit alternating trends between market oversupply and undersupply, and so on.

There is one source of price volatility that differs between the gas and oil markets. Prices may exhibit seasonal patterns that are expected by the market. There is more price seasonality in the natural gas market than the crude oil market. Subtracting the volatility for expected seasonal price changes still leaves natural gas more volatile than crude oil but the differences are less.

The natural gas price spikes in December 2000 and February 2003 far exceed (in percentage terms) any price spikes seen in the crude oil market. This likely reflects structural differences in the ability of the two markets to respond to unexpected supply disruptions or demand surges. Market structural differences, such as the greater diversity of crude oil supply sources and ability to store crude oil closer to end users, could account for differences in price volatility (between natural gas and crude oil) beyond those related simply to the inherent differences in seasonality between the two markets.

QUESTIONS FROM SENATOR CAMPBELL

Question 1. The EIA analysis of the tax provisions in the Energy Conference Report of 2003 shows that domestic gas production from unconventional gas sources (Section 29 tax credit encourages production of oil and natural gas from "non-conventional" sources—like Devonian shale, tight rock formations, and coalbeds—that are usually expensive and technologically challenging to produce) is expected to increase during the next 10 years. Is this the only provision in the tax section of the energy conference bill that will increase natural gas production in the near term?

Answer. Renewal of Section 29 tax credits is not the only provision of the Conference Energy Bill that could increase natural gas production in the near term, but it was the only provision that EIA could readily analyze with its National Energy Modeling System.

Question 2. Short-term natural gas supply constraints can be partly addressed by dispatching the most fuel-efficient gas fired-units first-either before or in place of older less efficient units. New units use about one-third less natural gas to produce the same amount of electricity. Has the EIA done any type of studies that looks into how much natural gas could be saved by using new combined cycle natural gas generation?

Answer. The EIA has estimated that approximately 47 percent of gas consumption by electric generators in 2002 (6.03 billion cubic feet per day) is attributable to relatively old generating units (units which entered operation in 1985 or earlier). If the power demand served by these older plants could be met by more-efficient modern plants, only 4.61 billion cubic feet per day would be required for the same generation, a savings of 1.42 billion cubic feet per day (24 percent of the 2002 consumption by electric generators). In fact, many new generating units are operating at relatively low utilization rates due to the overbuilt electric generating capacity market. The potential therefore exists to displace some generation from older and less-efficient units with output from new units. This displacement is occurring and is evidenced, for example, by the retirement or mothballing of some older plants.

There are, however, factors which may force the continued operation of some older units. First, transmission constraints may limit the ability of generators to ship power from new units to locations where that power could displace the output from older units. Note that many new generating units were built to serve local load, and the ability to sell electricity, if necessary, to remote demand was a primary consideration. In addition, many developers expected continued growth in the price of electricity. However, in many cases the expected local demand and/or price growth did not materialize, reducing the utilization of the new capacity. Consequently, many new units have become "distressed assets" that are candidates for sale or even mothballing, in part because they cannot sell power to remote markets where the plants might be more competitive.

Second, older units located near demand centers (especially urban areas) may be designated as "reliability must-run" plants that must operate at times to maintain the stability of the transmission system. These factors may force the continued operation of a considerable amount of older generating capacity for quite some time, reducing the overall demand for the newer, more efficient capacity.

QUESTIONS FROM SENATOR BINGAMAN

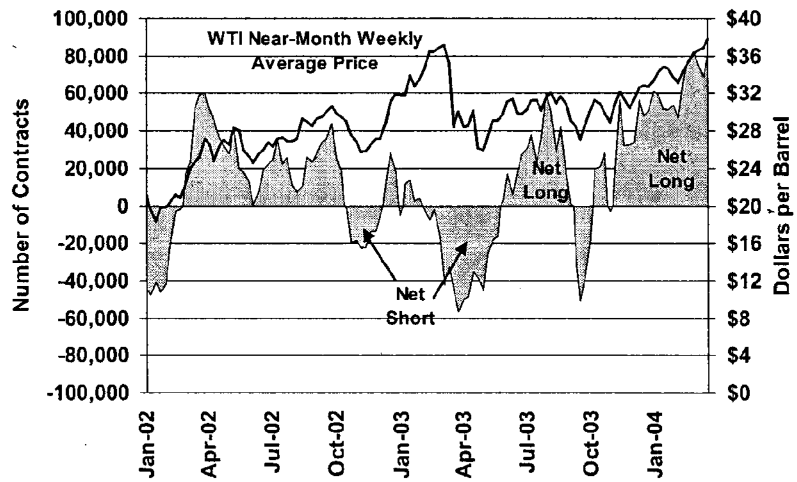
Question 1. Effect of increased speculation on oil markets.

The current trend of high oil prices has been suggested by some to be a result of increased speculation in crude oil markets.

Question 1a. Do you see speculators taking on a greater role in these markets, and if so, what has the effect been?

Answer. EIA feels that supply and demand fundamentals support prices for West Texas Intermediate (WTI) crude oil at $32-33 per barrel, or perhaps even a little higher. However, with current prices reaching as high as $38 per barrel in recent days, there does seem to be some price impact from the large net long position seen recently for the non-commercial participants in the New York Mercantile Exchange (NYMEX) contract (see chart below). While it is impossible to separate out the non-fundamental factors (i.e., speculators, fear of supply losses in the future, etc.), the net long position of speculators appears to have had some measurable impact.

Net Position of Non-Commercial Participants in NYMEX WTI Futures Contracts Since 2002 vs. WTI Price



Source: NYMEX Commitment of Traders Report, Commodity Futures Trading Commission. Graph includes data up to March 23, 2004.

Question 1b. Is volatility increasing as a result of their actions in the market? Are we seeing markedly higher prices overall as a result of this?

Answer. Even if volatility has increased recently (and it is not clear that it has), it would be difficult to attribute it to any one factor. But as stated in the answer immediately above, WTI prices are higher than current supply and demand fundamentals would dictate, albeit the impact is not as large as some analyst have stated recently.

Question 1c. Given your analysis, do you think that the data gathered by CFTC on net positions is accurate? Are there ways in which it could be improved?

Answer. Nothing in our analysis has led us to believe that the Commodity Futures Trading Commission (CFTC) data is not accurate. In fact, our relationship with CFTC leads us to believe that they exert great effort to make their data as accurate as possible. If there were any room for improvement, it would be more in terms of how people interpret their data. In defining "speculators," does this neatly correspond to the "non-commercial" category, or are there some large hedge funds included in the "commercial" category that more readily fit the "speculator" label? Or, in determining the net position, should one look at "futures" positions only or combine "futures" and "options" positions? It would be helpful if CFTC could take some steps to help users of their data become more knowledgeable about the definitions and categories, so answers to the questions asked above can be more consistently answered by different analysts.

Question 3. The past few weeks we have seen significant increases in gasoline prices. Several factors have been noted by our witnesses in an attempt to explain the reasons for the rapid increase. What is the current rate of refinery utilization?

Is it realistic to think that we can continue to operate at this rate? Are there specific regional issues that we should be looking into in more detail to help dissolve any bottlenecks in the system?

Answer. The 4-week average utilization for the week ending March 19, 2004 was 88.3 percent. The 5-year average utilization for the month of February is 88.3 percent, and for March is 89.7 percent. February and early March are typically times when refineries undergo maintenance and turnarounds to move from winter products to summer products. As a result, utilization is generally lower than during the summer months, which have averaged closer to 95 percent. During these periods of maintenance, 88 percent can be close to maximum utilization, given the capacity temporarily out of service. There is no way to determine "excess available capacity" during these times. This year, high crude-oil prices and strong backwardation (i.e., futures market prices being lower in the out months than the current month) provided strong incentives for refiners to run only as much as needed to meet immediate demand. During the summer when refiners have most of their capacity available to run, utilizations of 95 percent leave little excess capacity available to respond to unexpected imbalances in the supply system.

Demand has grown to fill excess capacity that was the prevalent in the 1980's. (Utilization in 1981 was 69%.) Since 1995, U.S. capacity has increased in existing refineries from 15.7 million barrels per day to 16.8 (1.1 million-barrel-per-day increase) in spite of continued shutdowns of small, less efficient refineries. Net imports of petroleum products have also increased to help meet rising demand. Net product imports in 1995 were 750 thousand barrels per day and averaged 1,603 thousand barrels per day in 2003. The tighter markets and higher prices seen since the year 2000 are increasing incentives for refiners to do more expansion, but this may be limited as capital budgets are being used to make the necessary changes for the new low-sulfur gasoline and ultra-low sulfur diesel programs. Product imports, particularly gasoline, are being used to help meet growing demand.

EIA's outlook for the short term is for continued tightness in gasoline and petroleum markets in general. While underlying tight world petroleum markets set the stage for tight U.S. markets, the growing loss of flexibility of the U.S. system (both production and distribution) increases the time needed to respond to regional imbalances. Regions like California, Chicago-Milwaukee, and now New York and Connecticut are particularly exposed to the possibility of price surges in that they are using gasoline that is hard to produce (limiting the number of suppliers that provide products to those regions), and any extra supplies that may be needed must usually travel some distance (1-3 weeks away), which delays resolution of any supply/demand imbalances. We know of no ready solutions to easing the bottlenecks that have evolved. Any actions that provide additional flexibility rather than limiting flexibility work in the right direction from a supply perspective.

Questions From Senator Feinstein

Question 1. The Energy Information Administration recently issued a report analyzing the Energy Bill, particularly as it related to natural gas and gasoline production, consumption, and prices. My reading of the analysis is that the energy bill does nothing to decrease petroleum or natural gas consumption, does nothing to reduce petroleum imports, nor does it reduce the price of natural gas by 2010.

Can any of the witnesses explain to me why the federal government should spend at least $14 billion on a bill that purports to alleviate our natural gas problems or reduce our dependence on foreign oil when in fact EIA's numbers show that neither of these goals will be accomplished?

Answer. The Department of Energy Organization Act provides the Energy Information Administration (EIA) with an element of statutory independence and EIA does not advocate, recommend, nor promote policies. In EIA's report, *Summary Impacts of Modeled Provisions of the 2003 Conference Energy Bill*, natural gas consumption in 2010 is reduced by 210 billion cubic feet for the year and petroleum consumption is reduced by 27,000 barrels per day. Imports as a share of petroleum product supplied are reduced from 58.0 percent in the reference case to 57.6 percent in the Bill case in 2010. Lower 48 natural gas wellhead prices are about the same in the Conference Energy Bill as in the reference case in 2010.

Question 2. Natural gas is the fuel of choice in California. The benefits of natural gas are well known. However, natural gas supplies are tight and the costs of gas have risen. The renewable fuels standard that is in the Energy Bill will increase ethanol production by approximately 2 billion gallons over the next 10 years.

In order to get those ethanol plants sited, they will have to be powered by natural gas. How much natural gas will be used by these plants? What will the price impact be on natural gas?

Answer. A 2 billion gallon increase in annual ethanol production will require an additional 89.8 billion cubic feet of natural gas each year. This assumes that the incremental output is from dry mills operating at 2004 efficiency levels, that all process energy is from natural gas, and that the electricity required to operate the ethanol plants is generated from natural gas. While EIA has not directly modeled the price impact of this additional consumption, interpolation of changes in existing analyses shows that a 2 billion gallon increase in ethanol production would increase the price of natural gas at the wellhead in 2014 and thereafter by about $0.02 in 2002 dollars per thousand cubic feet, or by no more than 0.5 percent.

ADDITIONAL QUESTIONS FROM SENATOR FEINSTEIN

Question 1. On Monday, March 1, the Energy Information Administration released its weekly retail gasoline prices report. Across the country, gas prices have risen an average of 16 cents since mid January. In California, the numbers are even more startling. The overall average of California's reformulated gasoline rose from $1.71 on January 12 to $2.16 on March 1. At the same time, California's refineries are switching from winter blends to summer blends and all of our reformulated gasoline must have ethanol in it since the state banned MTBE as of January 1, 2004.

Questioon 1a. Why are gasoline supplies so limited in California?

Answer. The supply limitations can be summarized as stemming from three factors: 1) The California refinery system runs near its capacity limits, which means there is little excess capability in the region to respond to unexpected shortfalls; 2) California is isolated and lies a great distance from other supply sources (e.g., 14 days travel by tanker from the Gulf Coast), which prevents a quick resolution to any supply/demand imbalances; and 3) the region uses a unique gasoline that is difficult and expensive to make, and as a result, the number of other suppliers that can provide product to the State is limited. This year, freight rates for tankers that transport gasoline were exceptionally high, requiring a very high California gasoline price to overcome the transportation cost and make it profitable to send product to California.

Question 1b. What will the effect of the closure of the Shell Bakersfield facility be on California's gasoline supply?

Answer. The simple answer is that losing capacity in an already tight market will just tighten it more. The product that is being lost will likely be made up by moving increased volumes from areas outside of the California refineries. The California Energy Commission (CEC) is looking into this problem.

Shell has indicated that the 66,000 barrel per day refinery provides 2% of California's gasoline (about 20,000 barrels per day) and 6% of the State's diesel. While this is considered a small refinery, the volumes it produces are still important to the State. It also produces other products such as lube oils and asphalt. Currently the refinery serves gasoline and diesel markets in Bakersfield, and it moves product north to a terminal in Fresno. That Fresno terminal is also served by suppliers in northern California. That means, if Bakersfield closes, the northern California suppliers must provide more product into Fresno and potentially Bakersfield. There are pipeline constraints that will require product to be moved by truck and railroad car in the short term.

Tightening the California market means tightening the Western market because these markets are linked. For example, CEC indicated the northern California suppliers that will be replacing the Bakersfield refinery product now send about 30,000 barrels per day of gasoline to Oregon (as of 2002). In addition, refineries in the Pacific Northwest supply product to California. While the market is operating smoothly, the equilibrium price effect is likely to be small, but the chances for price surges increase in a tighter market even more dependent on long supply chains.

Question 1c. What can be done to increase supply to California?

Answer. Increases in supply and increases in supply flexibility would both help the California market. Further clean gasoline requirements (e.g., California Air Resources Board (GARB) IV) may further reduce refinery flexibility and even the capability of existing capacity to produce gasoline. Meanwhile demand keeps growing, and new supply must come from outside the State or from expansion of refineries within the State. There is room for some refineries in California and Washington State to increase capacity, but such expansions take time and involve many regulatory and environmental issues that must be addressed. Assuring that a process exists to identify regulatory and environmental hurdles to determine if quick solutions can be found would be helpful. As more product volumes come from outside the State, it would be helpful to assure infrastructure can be developed in a timely fashion to accommodate the necessary tankers and flows without jeopardizing environmental quality. For example, expansion of tank capacity at or near ports would help to accommodate more volumes. It should be noted that completion of the Longhorn Pipeline may allow California refiners to provide less product volume into neighboring States and more for California. Regarding flexibility, distribution infrastructure is key. To the extent that expansion of delivery infrastructure (pipelines, terminal tanks) is needed to meet growing demand, it would be helpful for government and industry to work together to try to derive solutions that will ease supply delivery while maintaining environmental quality.

Question 1d. What is the impact of the 2% ethanol requirement on California's gasoline?

Answer. The Federal 2 percent by weight oxygen requirement in reformulated gasoline, in combination with California's MTBE ban, requires refiners to add ethanol to RFG. Because ethanol raises the Reid vapor pressure (RVP) of gasoline, the base gasoline blend must be manufactured to a very low RVP, reducing refiners' flexibility in gasoline blending. Also, ethanol-blended gasoline cannot be commingled with other gasoline types, mainly due to the possibility of the ethanol increasing the Volatile Organic Compounds (VOCs) emissions in other gasolines.

Question 1e. What is the long-term outlook for California's gasoline supply and prices?

Answer. While EIA does not forecast regional supply and prices, we would expect the supply/demand balance to remain tight for some time. California is considering a yet cleaner and still more difficult to produce gasoline (CARB IV) before the first year of supplying GARB III is complete, which indicates continued tight markets for some time. Two factors are working to relieve this situation. Demand will eventually grow to the point where companies will find it beneficial to establish large firm contracts with refiners outside the State. Currently existing refiners can provide adequate product to meet demand most of the time, which limits incentives to commit to regular firm contracts from elsewhere. The third-party trading market has also been limited, since refiners within the State can handle most of the demand. This potentially growing third-party market could increase liquidity and volumes available in the short-term markets. Second, the projected opening of the Longhorn Pipeline this summer should help to allow California refiners to provide more California gasoline as more product from Texas flows into the Southwest.

Question 2. What will the impact of the renewable fuels standard, should it pass, be on the state of the refineries? It is my understanding that refineries are currently operating at 93%. It is also my understanding that reformulated gasoline, when blended with ethanol with summer blends, has to be extremely clean. As a result, California's refiners lose about 10% of gasoline volume eight months of the year when they have to blend summer blends with ethanol.

Answer. The major volume impact of using ethanol in gasoline pertains to reformulated gasoline, but the use of ethanol in reformulated gasoline is being driven by methyl tertiary butyl ether (MTBE) bans, rather than the renewable fuels standard. If MTBE were still being used, reformulated-gasoline-producing refiners in many areas likely would find it more economic to meet the renewable fuels standard by buying credits from refiners who are adding ethanol to conventional gasoline in other areas of the country such as the Midwest. But concerns over MTBE are causing many States and companies to back away from MTBE. Ethanol is being used to replace MTBE for 3 major reasons: 1) In reformulated gasoline (RFG), ethanol helps to meet the Federal oxygen requirement, since ethanol contains oxygen as did MTBE; 2) Ethanol helps to replace the octane lost when MTBE was removed; and 3) Ethanol helps to dilute emission characteristics in the remaining gasoline blending components. For example, ethanol contains no aromatics (which increase emissions), so ethanol dilutes the aromatic content of the gasoline blending components to which it is added.

Question 3. If the renewable fuels standard is enacted, and refiners choose to use ethanol in reformulated gasoline, should we expect further shortfalls in gasoline throughout the country?

Answer. Refiners would generally be using ethanol in reformulated gasoline (RFG) as a result of MTBE bans rather than from a renewable fuel standard. Had MTBE not become a water quality concern, RFG-producing refiners in many areas likely would find it more economic to meet the renewable fuels standard by buying credits from refiners that are adding ethanol to conventional gasoline. But concerns over MTBE are causing many States and companies to back away from MTBE. This leaves ethanol as one of the only alternatives to meet the RFG oxygen requirement. Furthermore, ethanol helps some refiners replace lost MTBE volumes and associated lost octane.

Increased ethanol use in the next 5-10 years or so would likely be supplied mainly from the Midwest. As a result, another separate supply chain is being used to meet gasoline demand. That supply chain would be most critical for RFG, since the base

RFG gasoline stock to which ethanol is added is not a finished gasoline and does not meet driveability or emission requirements. Thus, any interruption in either the gasoline base stock or the ethanol supply could result in temporary shortages. If the ethanol-blended conventional market grows to the extent that sub-octane conventional gasoline blendstocks are being used to blend with ethanol, it could also see a dependence on the separate ethanol supply chain. However, conventional gasoline is generally easier to adjust to produce a finished product than is RFG.

Question 4. What would the impact of the seasonal variations section of the renewable fuels standard be on refiners and gasoline supply, particularly if it is used in reformulated gasoline areas?

Answer. EIA is not convinced that the seasonal requirements will have a large impact, at least in earlier years of the mandate. Ethanol use in RFG would not be affected by the seasonal requirement if the oxygen requirement remains in place, since ethanol is providing the needed oxygen content. Even if the oxygen requirement for RFG were to be removed, ethanol likely would be used by many refiners to replace the octane lost from MTBE and to dilute other gasoline components that contribute to emissions. This would cause them to use ethanol in the summer as well as the winter. Generally it is easier to use ethanol in conventional gasoline than in RFG, but some suppliers might find it less attractive in the summer due to its tendency to increase the rate of evaporation of gasoline (i.e., raise Reid vapor pressure or RVP). Still, suppliers in the Midwest currently use ethanol all year round, and this region would be expected to use ethanol beyond the mandated amounts, thereby producing credits for others to purchase.

Question 5. Would it be smarter to mandate ethanol use only in conventional gasoline?

Answer. In some States with MTBE bans, ethanol is helping to replace the MTBE that is lost in RFG. While there is a net volume loss in the summer months, some refineries would find it more difficult to produce an oxygenate-free RFG that meets both driveability and environmental specifications than to use ethanol. A restriction on where ethanol may be used only serves to place further restraints on an already constrained supply system. Also, if the ethanol mandate allows for and is able to accomplish a liquid credit trading market, refiners producing RFG would theoretically be able to buy credits if necessary to meet the mandate without using ethanol.

DEPARTMENT OF ENERGY,
CONGRESSIONAL AND INTERGOVERNMENTAL AFFAIRS,
Washington, DC, May 18, 2004.

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

DEAR MR. CHAIRMAN: On March 4, 2004, Guy F. Caruso, Administrator, Energy Information Administration, testified regarding energy supply forecasts. On April 20, 2004, we sent you the answers to 18 questions for the hearing record.

Enclosed are the remaining answers to seven questions submitted by Senators Bingaman and Schumer.

Enclosed also is the edited transcript, and three inserts that were requested by Senators Wyden, Landrieu and Craig 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,

RICK A. DEARBORN,
Assistant Secretary.

[Enclosures.]

QUESTION FROM SENATOR BINGAMAN

STRATEGIC PETROLEUM RESERVE (SPR)

Question 2. The Strategic Petroleum Reserve was established in 1975 in an attempt to protect the United States from a severe energy supply disruption. This action was taken in an environment that enjoyed significant excess refining capacity and voluntary actions by companies to hold discretionary stocks. Since 1975, energy markets have further evolved both globally and domestically. On the domestic front, we've seen companies move away from holding discretionary stocks and move into just-in-time style management of their inventories of crude and products. This has meant that the 'cushion' which we used to depend on is in fact disappearing. An in this environment, we are exposed to increasingly frequent momentary disruptions that do clearly cause economic damage. Given the significant shifts in the commercial environment of petroleum and petroleum product markets, it would seem that a comprehensive review of our approach to the SPR may in fact be necessary. What does this mean for our approach to the SPR? What changes may be necessary?

Answer. The Energy Policy and Conservation Act (EPCA) envisions that the free market will balance the supply and demand of oil, and oil from the SPR will be withdrawn and sold only in extraordinary circumstances, and then only upon a decision by the President, or as a limited test sale or exchange.

The Act also provides for our membership in the International Energy Agency. This membership allows us to leverage the concept of strategic petroleum stockpiling, increasing deterrence value, and sharing costs and benefits with other countries.

Despite evolutionary changes in the petroleum industry, and the geographical sources of the world's oil supplies, the basic concepts of the Act still serve us well. We should allow free markets to operate with minimal intervention by the Government. When the Government is required to intervene it should augment supplies and use the mechanisms of the free market to distribute the Government supplies of petroleum.

The reduction of private inventories over time definitely increases the value of strategic reserves. That is a contributing justification for filling the Reserve to its capacity. That is also one reason the President's National Energy Policy provides for the Government to encourage other nations to build and maintain strategic petroleum reserves.

QUESTIONS FROM SENATOR SCHUMER

Question 1. What is the potential for a gasoline shortage to be created or exacerbated this summer as a result of the loss of gasoline volume in states forced to use ethanol by the oxygenate requirement? Are there reliable sources of marginal supply from Canada, South America, or other markets that could alleviate any such shortage?

Answer. The primary change in the gasoline supply picture this summer stems not from the oxygenate requirement in reformulated gasoline (RFG), which has been in place since the program began in 1995, but the ban on the use of methyl tertiary butyl ether (MTBE) in New York and Connecticut, following a similar ban in California. Since MTBE had previously been the primary oxygenate used in those areas to satisfy the oxygen requirement, suppliers in those areas have no practical choice but to replace the banned MTBE with ethanol.

Analysis by the Energy Information Administration (EIA) in advance of the MTBE ban in New York and Connecticut found that the ban would force changes in supply patterns and some logistical challenges that could produce some transitional problems. The major supply uncertainty found in EIA's analysis was the continued availability of gasoline from traditional import supply sources to the area, given that some foreign refiners might be unable or unwilling to produce the base gasoline, called reformulated gasoline for oxygenate blending (RBOB), to which the ethanol would be added. However, EIA found that U.S. refiners should be capable of making up any shortfall of RBOB, with import sources presumably shifting to supply MTBE RFG or conventional gasoline to areas outside of New York and Connecticut.

Question 2. Have you been made aware of any automotive performance issues associated with the use of ethanol in gasoline in states required to do so by the oxygen mandate? If so, what steps can be taken to alleviate the problem in the face of a tight market?

Answer. EIA is not aware of any significant automotive performance issues associated with the use of ethanol as compared to MTBE in gasoline. While both of these oxygenates have a lower energy content than the base gasoline they replace, and thus theoretically result in somewhat higher gasoline demand in areas where they are used, no significant difference in performance has been reported between the two blends. Ethanol blended in gasoline, at levels up to 10 percent by volume, has been in widespread use in many parts of the United States for more than a decade.

Question 3. We're currently experiencing record supply lows and gasoline price highs nationwide, and facing the possibility of supply disruptions from several foreign providers. If we have these supply disruptions, what would the price impact be? At what point would DOE acknowledge that we have a severe economic disruption in the energy sector meeting the threshold for releasing oil from the SPR?

Answer. The price impact of a given supply disruption will depend on the size of the disruption, its duration, and a number of other factors at work in the market at any given point of time, such as the existence of spare production capacity, the size of commercial inventories of crude oil and petroleum products, weather, and the nature of the disruption itself. As a general rule of thumb, the EIA expects that an oil supply disruption that results in one million barrels per day of current supply being withheld from the market, and the disruption lasts for a period of six months, that could raise world oil prices on average by $3-$5 per barrel. The average increase cited in this rule of thumb can mask significant short-term price spikes.

The statutory requirements for an emergency drawdown and sale of oil from the SPR are set out in the Energy Policy and Conservation Act. These requirements include the existence or imminent threat of a severe energy supply interruption; a severe increase or expected increase in the price of petroleum; and anticipation that the disruption will have an adverse impact on the economy. There are no specific thresholds for determining when or if these statutory requirements have been met. DOE monitors market developments closely, and in the event of a supply disruption or imminent threat of a supply disruption, DOE will conduct an analysis of the specific situation and make a recommendation regarding the use of the SPR based on the facts at that time.

STRATEGIC PETROLEUM RESERVE USE

Question 4. At the time the SPR was created, the structure of the nation's oil market was different and industry was more willing to hold on to supply inventories and a number of other factors existed. Given that oil markets now function differently, is there a need to reevaluate the philosophy on how to use the SPR?

Answer. SPR use, under the Energy Policy and Conservation Act (EPCA), enacted in 1975, and the authorities granted and objectives stated therein have proven resilient over the past 29 years. They provide appropriate standards for use of the SPR, and flexibility for changing conditions. Importantly, they allow for consideration of international conditions and the state of our energy security. There is no need, at this time, to either increase or decrease the authority for selling oil from the reserve, nor is there any need at this time for more or less guidance concerning acquisition of oil for the SPR.

Question 5. Russia is currently not included in the list of top suppliers of U.S. oil imports, even though it has risen to the top of the global production list with an output of around 9 million barrels per day. Is there any hope that the United States could look to increased Russian supply in an effort to hedge against OPEC dominance and instability in our other suppliers?

Answer. The U.S. is steadfast in working with Russia to increase its shipments of oil to the U.S. Russia currently supplies about 1.5 percent of U.S. crude oil imports or about 149,000 barrels per day to the U.S. We also import about 104,000 barrels per day of refined petroleum products from Russia. Russia wants to increase its exports to the U.S. but is hampered by an inadequate infrastructure. President Putin and Russian companies have stated their desire to provide oil to the U.S. and estimate that Russia could provide up to one million barrels per day or 10 percent of U.S. imports. In July 2002, the Russian oil company Yukos began direct exports of two million barrels of oil monthly for six months on a trial basis to the Gulf of Mexico.

Our two governments have been working closely together over the last three years to enhance trade and investment in Russia's energy sector and expand Russia's markets. Among the many undertakings, we have held two Commercial Energy Summits to catalyze partnerships between our energy companies. We have reinvigorated the Energy Working Group that on an ongoing basis cooperates on, among other issues, investment and facilitating trade. Under the Camp David initiatives, agreed to in October 2003, President Bush and President Putin support efforts to advance the development of the Murmansk pipeline and port system. Murmansk is an ice-free deepwater port that could economically expand Russia's oil markets including Russia's exports to the U.S. Shipments from Murmansk to the U.S. are actually a shorter distance than exports from the Persian Gulf. We are working with the Russian government as it addresses energy tax issues and its regulatory regime for licensing oil and gas fields by sharing the U.S. experience and the need to provide incentives and stability for investment.

Both governments have a shared goal of more Russian oil to the U.S. and will continue to work on creating an environment to foster commercial energy cooperation that will expand markets for Russian energy.

Question 6. Could you comment on the impact that China's continuing industrialization and growing energy demand is going to have on the world markets, particularly in oil and natural gas? What steps can be taken to anticipate and mitigate any severe economic impacts that may result from a surge in Chinese energy demand?

Answer. In accordance with its pace of industrialization, Chinese demand for oil has been growing steadily. China became a net overall oil importer in 1993. In 2003, China's demand for oil surpassed that of Japan and it became the second largest oil consumer in the world, after the United States. Imports, 60 percent of which come from the Middle East, now account for one-third of China's oil demand. The International Energy Agency estimates that China's imports may account for 60 percent of consumption by 2010, and 80 percent by 2030. Rapid growth of energy demand in China could put upward pressure on world energy prices.

Such strong growth in energy demand, in conjunction with its potential impact on sustainable economic growth, has been recognized by the highest levels of Chinese leadership. Their key responses have been a commitment to construct a State Petroleum Reserve (SPR), greater participation in foreign exploration and production activities by Chinese oil and gas companies, and supply diversification away from the Middle East.

CONSTRUCTION OF STATE PETROLEUM RESERVE

After a decade of consideration, China included in its 10th five-year plan (2000-2005) the task of building strategic oil reserves. In summer 2003, Beijing reportedly selected the following sites for a strategic oil reserve: the northeast port of Dalian, Huangdao in eastern province of Shandong, and Aoshan and Ningbo in East China's Zhejiang province. Chinese plans for SPR construction reportedly come in two phases, leading to approximately 30 days of consumption coverage by 2010.

FOREIGN FOREIGN EXPLORATION AND PRODUCTION

China has been acquiring interests in exploration and production abroad. Chinese majors have acquired oil concessions in Kazakhstan, Venezuela, Sudan, Iraq, Iran, Peru, and Azerbaijan. The most significant deal thus far is the acquisition of a 60 percent stake in the Kazakh oil firm Aktobemunaigaz, which came with a pledge to invest significantly in the company's future development. Also, China has gained shareholdings in Australian and Indonesian gas fields and is reportedly looking to take a further stake in the Gorgon gas field offshore northwest Australia.

SUPPLY DIVERSIFICATION AWAY FROM THE MIDDLE EAST

Russia's Far East is increasingly seen as a potential source of Chinese crude oil imports. The most notable proposed initiative is to build a $2.5 billion pipeline between Anagarsk and Daqing that would carry 600,000 bbl/d of crude oil. While a memorandum of understanding was signed between China's state-owned China National Petroleum Corp. and Yukos Oil of Russia in June 2003, it remains unclear whether the deal would materialize in light of political uncertainties in Moscow and a competing one million bbl/d pipeline proposal by Russian pipeline operator Transneft that would export Russian gas to an export terminal at the Pacific coast port of Nakhodka. China is also stepping up activity in Kazakhstan, reflecting a synergy between Chinese efforts to diversify supply and Kazakh interest in Chinese market, as the Central Asian country plans to boost output to up to 3.5 million bbl/d in 2015 from around one million bbl/d in 2003.

ANADARKO PETROLEUM CORPORATION,
Houston, TX, April 6, 2004.

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

DEAR SENATOR DOMENICI: Thank you for the opportunity to appear before the Senate Committee on Energy and Natural Resources on March 4, 2004. 1 appreciated the chance to give testimony regarding energy supply forecasts.

Enclosed please find the list of questions and my responses to be included in the record.

Sincerely,

RICHARD J. SHARPLES,
Senior Vice President, Marketing and Minerals.

[Enclosures.]

QUESTIONS FROM SENATOR DOMENICI

Question 1. I believe that producing the energy this Nation depends on AND maintaining a healthy environment are NOT mutually exclusive goals. Can industry explore and produce oil and gas on public lands in a manner that takes care of the environment, maintains wildlife habitat and accommodates other users?

Answer. Absolutely. Through technology that is advancing daily, industry can explore and develop America's gas resources without harming the environment. Anadarko has successfully demonstrated care for the environment in sensitive habitats where we work—from the Gulf of Mexico to Alaska. We've proved that we can co-exist with nature, exploring for and producing natural resources with minimal physical impact to the surroundings.

It's also important to note that when we talk about access, we're talking about access to *non-park* federal lands—such as off the West and East coasts, the Eastern Gulf of Mexico, parts of Alaska and other onshore areas particularly in the West—that are currently off limits. These resource rich areas can help provide vital sources of energy for American consumers.

Question 2. How important is the role of production from public lands in increasing domestic production?

Answer. Production from public lands is extremely important. Without increased access, I don't believe U.S. natural gas production can grow at a price level that the market can bear.

The NPC 2003 study concluded that removing the OCS moratoria and reducing the impact of conditions of approval on the Rocky Mountain areas by 10% per year for 5 years would add 3 Bcf per day to domestic production in 2020 and would reduce the average price of natural gas by as much as 60 cents in nominal terms—which translates into a $300 billion savings to consumers over 20 years.

Question 3. In your testimony you spoke to the impact of the conditions of approval for oil and gas operations in the Rocky Mountain areas. I assume you're speaking largely of the Department of the Interior and its leasing and permit process.

Did I understand correctly that these impacts have resulted in a production decrease?

Answer. While there has been increased production from the Rockies, the region's growth potential is impaired by the restrictions and delays in the permitting process. In order to compensate for the steep declines in mature basins, we need to generate greater growth from the Rockies and other unexplored areas.

We think that had it not been for these delays, we could have produced more.

Question 3a. Has the Department been able to improve its processing time or its predictability and consistency for issuing drilling permits?

Answer. Overall the answer is no. Across most of Wyoming, it currently takes 9 to 12 months to get a permit processed (where it used to take 3 months for permits), and the situation seems to be getting worse.

But the Bureau of Land Management (BLM) is attempting to make improvements. A positive example is the Buffalo (Wyoming) Field Office where they've put policies in place to enact a 46-day turn-around for permits and they've increased their staffing to better handle the volume of activity. The 46-day policy just went into effect in January and we haven't seen the results yet, but we're hopeful. We commend that office for a step in the right direction.

Question 3b. What seems to be the difficulty in fixing this problem?

Answer. It's largely a manpower deployment issue combined with the experience level of staff. The activity has increased in the Western States, but there's simply not enough people to handle the workload.

We estimate that the impact of delay on net present value (NPV) is costing the Federal Government approximately $12 million in royalty value for a single project when an environmental impact statement (EIS) takes 60 months instead of 18 months. Likewise, if the BLM could improve permit processing time by 6 months, it would increase the present value of royalty paid to the Federal Government by approximately $500,000 to $750,000 per year for a typical project.

QUESTION FROM SENATOR CAMPBELL

Question. The EIA recently analyzed three restricted-supply scenarios by 2025 and compared each with the EIA energy forecast. The three scenarios were:

- No new Alaska gas pipeline;
- New LNG terminals limited to 3 totaling 2.5 Bcf;
- Future conventional gas production remaining stagnant.

If these scenarios held true, lower-48 state wellhead price impact in 2025 would range from 20 cents/Mcf higher in the no-Alaska pipeline case to $1.21/Mcf higher if all three scenarios were combined. Do you believe that these price assumptions are realistic or do you believe that they will be better or worse?

Answer. The Alaska sensitivity seems realistic, but the impact could be as much as $0.50.

Based on internal modeling at Anadarko, and assuming current public policies are the same, we would expect the impact of no new Alaska pipeline plus constrained LNG import capacity to 2.5 Bcf/d to have at least a $2.00 impact on the price in 2025. Furthermore, we expect that the impact of no new Alaska pipeline plus constrained LNG will mean that 20% of gas demand from EIA's reference case will be forced out of the market. Under current policies and basin maturities, North American gas production has little opportunity for growth, even the 1% per year growth assumed by the EIA reference case. Therefore, any disruption to anticipated supply must be matched by a corresponding disruption in demand. We anticipate that natural gas pricing information will be used to ration demand, but will have little impact on the ability of the nation to supply more gas (under current policies). The EIA assumes that Alaskan supply will equal 2.7 Tcf in 2025 and that LNG imports will equal 4.8 Tcf. Constraining LNG import capacity to 2.5 Bcf/d will result in LNG supplies equal to only 0.1 Tcf in 2025. Therefore, the supply from this sensitivity will effectively be reduced by 6.6 Tcf, or 20% of the 32.21 Tcf of gas consumption expected. Therefore, we conclude that the only way for the market to grow if LNG capacity is restrained and Alaska is not approved is to make changes to public policy in other arenas particularly access to new exploration acreage.

An assumption that future production from conventional reservoirs could remain stagnant, or flat, we view as optimistic. To the contrary, we expect that production from conventional reservoirs will decline over the next 20 years by about 1% per year (This is consistent with the NPC).

Questions From Senator Feinstein

Question 1. The Energy Information Administration recently issued a report analyzing the Energy Bill, particularly as it relates to natural gas and gasoline production, consumption, and prices. My reading of the analysis is that the energy bill does nothing to decrease petroleum or natural gas consumption, does nothing to reduce petroleum imports, nor does it reduce the price of natural gas by 2010.

Can any of the witnesses explain to me why the federal government should spend at least $14 billion on a bill that purports to alleviate our natural gas problems and reduce our dependence on foreign oil when in fact EIA's numbers show that neither of these goals will be accomplished?

Answer. There are no quick fixes or easy answers when it comes to an energy policy for America. There are, however, important steps we can take together to improve the situation and relieve our growing dependence on imported energy. Many of them are contained in the comprehensive energy legislation pending before the Congress which we see as a good and necessary start toward greater American energy independence. Specifically, it—

- Streamlines permitting processes for exploration and development programs.
- Renews certain incentives like Section 29 tax credits, which have historically proven effective in increasing U.S. supply.
- Reduces barriers to gas pipeline permitting and construction.
- Imposes deadlines on appeals delaying offshore exploration and development.
- Authorizes the Alaska Natural Gas Pipeline which can bring 35 Tcf of currently stranded natural gas to the Lower 48 states.

Passing this energy legislation is an important first step to begin to address the issues and concerns raised by both the EIA in their Energy Outlook and the National Petroleum Council in their 2003 report on Balancing Natural Gas Policy.

In addition to the Energy Bill, there are several things—mostly administrative—that don't require an act of Congress:

- Add more BLM staff, both to speed up the revision of the RMPs and to speed up well permit reviews.
- Streamline the project approval process.
- Eliminate duplicative or conflicting requirements among state and federal agencies.
- Set time limits for staff decisions.
- Write clear and binding procedures for project approval, from the environmental impact statement stage through well permitting, and make it clear up front what steps operators will have to satisfy to get approval for their projects.

Longer term, we need more frequent and regular leasing in areas that are not under moratoria—Alaska and the Eastern Gulf are examples.

And we need the moratoria to be lifted in those areas where the resource potential is greatest, and where the technology and the infrastructure exist today to cost-effectively find, develop and produce that gas.

Question 2. Natural gas is the fuel of choice in California. The benefits of natural gas are well known. However, natural gas supplies are tight and costs of the gas have risen. The renewable fuels standard that is in the Energy Bill will increase ethanol production by approximately 2 billion gallons over the next 10 years.

In order to get those ethanol plants sited, they will have to be powered by natural gas. How much natural gas will be used by these plants? What will the price impact be on natural gas?

Answer. Anadarko does not process ethanol and is not the most appropriate company to respond to this question.

GASOLINE PRICES

Regarding your questions about gasoline prices—Anadarko does not refine or market gasoline, and we believe these questions would be better directed at one of the integrated companies.

1) On Monday, March 1, the Energy Information Agency released its weekly retail gasoline prices report. Across the country, gas prices have risen an average of 16 cents since mid-January. In California, the numbers are even more startling. The overall average of California's reformulated gasoline rose from $1.71 on January 12 to $2.16 on March 1.

At the same time, California's refineries are switching from winter blends to summer blends. And all of our reformulated gasoline must have ethanol in it since the state banned MTBE as of January 1, 2004.

- Why are gas supplies so limited in California?
- What will the effect of the closure of the Shell Bakersfield facility be on California's gasoline supply?
- What can be done to increase supply to California?
- What is the impact of the 2% ethanol requirement on California's gasoline supply?
- What is the long-term outlook for California's gasoline supply and prices?

2) What will the impact of the renewable fuels standard, should it pass, be on the state of the refineries? It is my understanding that refineries are currently operating at 93%. It is also my understanding that reformulated gasoline, when blended with ethanol with summer blends, has to be extremely clean. As a result, California's refiners lose about 10% of gasoline volume eight months of the year when they have to blend summer blends with ethanol.

3) If the renewable fuels standard is enacted, and refiners choose to use ethanol in reformulated gasoline, should we expect further shortfalls in gasoline throughout the country?

4) What would the impact of the seasonal variations section of the renewable fuels standard be on refiners and gasoline supply, particularly if it is used in reformulated gasoline areas?

5) Would it be smarter to mandate ethanol use only in conventional gasoline?

RESPONSES OF PAUL KOONCE TO QUESTIONS FROM SENATOR DOMENICI

Question 1. What are the greatest challenges you see facing proposed LNG facilities in the U.S.? And, do you think that there will be adequate take-away capacity to deal with anticipated LNG imports?

Answer. Perhaps the greatest challenge LNG faces is the perception by some that it is not safe, or presents an inherently significant security risk. This perception is incorrect, but it is proof that policymakers and the public must be better informed about LNG, its importance to our energy supply diversity, its safety and security characteristics, and the steps that have been taken in recent years to increase safety and security at LNG facilities.

Even with such an education effort, however, nothing will fully eliminate the "Not in My Backyard" opposition that now is frustrating all sorts of energy infrastructure development. Many state and local groups will oppose LNG projects regardless of the benefits the benefits to consumers and the economy, simply out of a desire to maintain the status quo. These groups will often use safety and security concerns to oppose projects when their real objections lie with concerns about property values, opposition to any future development, and the perceived impact on their "quality of life." It is incumbent upon elected officials, opinion leaders and the industry to explain why the status quo is not an acceptable alternative. High natural gas prices are a real "quality of life" issue, and have a real effect on jobs, the economy and environmental quality. This is why is it important to have an LNG facility approval process that weighs the larger public good against narrower, parochial interests.

Such a consolidated process now exists at the Federal Energy Regulatory Commission (FERC); but as you know, it is being challenged. I'll save further comment on this problem until Question 5, but suffice it to say that a national focus on these problems is crucial.

Your question about pipeline take-away capacity is also important to the debate over increased LNG supplies. As stated in my written testimony, LNG import capacity expansions must also happen in conjunction with pipeline take-away capacity upgrades. For example, Dominion has announced plans to increase throughput capacity at our Cove Point LNG facility from 1 Bcf/day to 1.8 Bcf/day, but this is dependent upon FERC approval of two associated pipelines to move that increased that capacity away from the terminal and into the market.

Question 2. EIA projects nine to twelve LNG facilities to serve the United States will be constructed by 2025. Do you agree with that prediction?

Answer. The recent National Petroleum Council[1] report on natural gas supplies projects that the four existing LNG terminals will be fully utilized by 2007, and that seven additional terminals will be needed in North America to meet demand through 2025. Not all of these terminals would necessarily be constructed in the United States; for example, facilities in Baja California, the Bahamas and Eastern Canada could serve the U.S. market with the construction of adequate pipeline takeway capacity. Nonetheless, current projections suggest that at least three or four LNG terminals would be needed in the continental U.S. as well.

There likely will be significant attrition among the approximately 40 LNG facilities that have been announced to date. These are complex, capital intensive projects that face significant siting and commercial challenges in making the transition from the drawing board to operational reality. The marketplace will be efficient in defining the equilibrium between the need for supply and the number of truly viable projects. What is important from a public policy perspective is to avoid the creation of unnecessary and duplicative regulatory process beyond that required to ensure public safety and security are protected.

Question 3. The FERC Hackberry decision protected LNG owners' authority over their own gas. What is the significance of that decision on existing and future LNG development?

Answer. LNG projects are capital-intensive and involve significant capital investment upstream of the regasification facility. Consequently, it was argued that subjecting regasification facilities to the FERC open season requirements would be a deterrent to the development of LNG supply for the United States, because a developer would be less likely to make the upstream investments if it lacked the certainty of access to commensurate regasification facilities once the supply was landed in the United States. The Hackberry decision waives the open season requirement and thereby provided developers with this certainty. In the absence of this decision, LNG terminal capacity would have to be made available to any party under open-access requirements, which likely would result in import capacity being allocated into smaller blocks. Compared to other potential global markets for LNG, this regulatory requirement would make the United States less attractive for LNG developers.

The Hackberry doctrine as written is designed to assist developers who have their "own" gas from having to submit to the open season process. For all the reasons stated above (the original answer), this doctrine should include all developers, so that these benefits may be realized by two companies working together, not just those companies with production affiliates.

Question 4. There has been much recent discussion about gas quality regarding condensate levels and interchangeability. These are two very distinct natural gas issues. I want to talk about interchangeability. As I understand it, interchangeability is an LNG matter that has to do with the ability to substitute LNG for traditional natural gas supplies. What are the concerns about doing that?

Answer. The concerns arise from the fact that much of the LNG available from overseas sources has a higher BTU content (i.e., heating value) than natural gas consumed in North America. Furthermore, the BTU content of LNG varies depending on the source, so there will not necessarily be consistency among LNG imported into United States markets. This is an issue because of concerns over whether the higher-BTU-content natural gas is compatible with home appliances, power genera-

[1] *Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy*, The National Petroleum Council. September, 2003.

tion equipment, pipeline compression engines, and other appliances and machines fueled by natural gas.

An industry collaborative that includes representatives from the entire natural gas value chain (i.e., everyone from natural gas producers to natural gas appliance and combustion turbine manufacturers) is working to resolve these interchangeability issues. This same group is working on the separate, but related natural gas quality issues associated with the effects of high natural gas commodity prices and shifts in the economics of natural gas processing.

The experience to date with existing operational LNG regasification facilities suggests that interchangeability solutions are site-specific and, therefore, that one-size-fits-all standards may not be appropriate. For example, at LNG terminals located sufficiently upstream of consuming markets, re-gasified LNG moving out of the terminal blends with North American gas supply in the pipeline system in such a way as to alleviate any concerns about high BTU content. At other facilities, natural gas is delivered to customers relatively soon after leaving the terminal, and therefore interchangeability must be addressed before the natural gas enters the pipeline system. For example, at Cove Point, we have a number of customers taking gas soon after it leaves the facility. As a result, the Cove Point terminal injects nitrogen into the natural gas before it enters the pipeline system, so that it meets gas equipment specifications without any further blending in the pipeline. We worked with our customers to develop this solution. This experience suggests strongly that the most efficient answer to the question is to provide LNG terminals, suppliers and customers with the flexibility to find the least cost means of meeting consensus-based interchangeability standards.

Question 5. In your testimony, you state that Congress may need to further clarify federal supremacy in the approval and siting of pipeline and LNG terminals to be used in interstate and foreign commerce. What is your assessment of the situation regarding the LNG proposal by Mitsubishi in Long Beach, California and the "jurisdictional turf war" taking place between the California PUC and FERC?

Answer. The "turf war" between the California PUC and FERC is exactly the kind of unnecessary, and counterproductive, federal-state conflict that I referred to in my written and oral testimony. The Sound Energy Solutions' ("SES") proposed terminal in California would be engaged in the importation of LNG from foreign sources. This transaction is clearly within the scope of the Federal Energy Regulatory Commission's jurisdiction under section 3 of the Natural Gas Act. The federal appellate courts have clearly affirmed FERC's interpretation of its section 3 authority to apply to the construction and siting of facilities for the importation of natural gas. FERC's recent declaratory order in the SES proceeding is firmly grounded in precedent and should be upheld if the State of California seeks judicial review.

Still, the appellate review process is time consuming and adds an element of uncertainty that can be counterproductive to creating a conducive climate for LNG terminal siting. For example, will other states choose to follow California's lead and raise jurisdictional challenges pending the final resolution of this matter in the courts? Furthermore, even if one assumes that FERC prevails in this matter, there may be other jurisdictional conflicts that create impediments to LNG project siting. Already, a number of states have used their delegated federal authority under the Coastal Zone Management Act and the Clean Water Act as mechanisms for blocking interstate pipelines that have already been approved by the FERC. There is no reason to believe that the same strategy will not also be pursued with respect to LNG terminals.

In other words, in addition to the prospect of jurisdictional conflicts between the application of federal and state law to LNG terminals and other energy infrastructure, there is the clear need to address the conflicts between federal statutes. The Natural Gas Act confers on FERC the exclusive authority over the approval and siting of interstate natural gas pipelines and facilities associated with importing and exporting natural gas. Still, in addition to the Natural Gas Act, the Congress has enacted a variety of environmental laws that provide other federal agencies, and in some cases state agencies acting pursuant to delegated authority, with jurisdiction over aspects of interstate natural gas pipeline siting. The certificates of public convenience and necessity that FERC issues under the NGA authorizing the construction of interstate natural gas pipelines include conditions requiring compliance with these laws. Furthermore, the environmental review that FERC conducts as part of its NGA certificate process includes extensive consultation with federal and state resource agencies. In addition, at the suggestion of INGAA, the White House Task Force on Energy took the lead in negotiating a memorandum of understanding among federal agencies with a stake in pipeline siting matters. This, however, does not include state agencies, who in many cases act pursuant to delegated federal authority. Unless something can be done to address this situation, there is the prospect that LNG terminals and interstate pipeline facilities that have been approved by their primary federal regulator, after a comprehensive and inclusive review process, could be delayed, if not blocked, by state agencies acting pursuant to delegated federal authority. While I would hope for a consensus based resolution of this growing conflict, this may well have reached the point where some statutory clarification of the hierarchy of federal laws that apply to energy project siting is advisable.

Question 6. How has the pre-filing process for pipeline projects at FERC been working?

Answer. FERC has done a commendable job reviewing pipeline applications, and approving in a timely manner those that meet the statutory "public convenience and necessity" standard. In recent years, tremendous progress has been made in engaging stakeholders in the process. FERC has spearheaded two distinct initiatives, the Federal Memorandum of Understanding ("MOU") agreement, which focuses on coordination between federal agencies, and the pre-filing process. The pre-filing process is a way to identify and address the issues and concerns of all stakeholders, including the public, federal, state, tribal and local authorities, before they become a problem associated with the application that the pipeline files with FERC. This is an excellent idea and we can point to some real world success stories as a result of this process. Still, our experience has been that while the pre-filing process has been successful in engaging the public, it has been less effective in addressing problems associated with some federal and state permitting agencies. These agencies do not have, as their mandate, the timely review of energy infrastructure that is in the public convenience and necessity. Some agencies even have chosen not to participate in the FERC process, or to play an openly hostile and non-constructive role. Given FERC's mission to meet "the public convenience and necessity," these inter-governmental conflicts are frustrating. Coupled with the federal MOU agreement, the FERC pre-filing process can result in a better more timely permitting process. Still, for the process to realize its full potential, we need all federal and state permitting agencies to get on board. Under the current framework, a single permitting authority with a narrowly-defined mandate can stop an entire project.

RESPONSE OF PAUL KOONCE TO A QUESTION FROM SENATOR CAMPBELL

Question. The EIA recently analyzed three restricted-supply scenarios by 2025 and compared each with the EIA energy forecast. The three scenarios were:

- No new Alaska gas pipeline
- New LNG terminals limited to 3 totaling 2.5 Bcf
- Future conventional gas production remaining stagnant

If these scenarios held true, lower-48 state wellhead price impact in 2025 would range from 20 cents/Mcf higher in the no-Alaska pipeline case to $1.21/Mcf higher if all three scenarios were combined. Do you believe that these price assumptions are realistic or do you believe that they will be better or worse?

Answer. If all three limiting factors were to indeed occur, it is very possible that the effect on prices would be even greater than that predicted by EIA. Today's sustained high prices of over $5 per Mcf provides ample evidence of this. The recent National Petroleum Council study on natural gas projects a steady increase in natural gas demand between now and 2025. The worst case restricted-supply scenario reviewed by EIA is essentially today's policy environment plus three new average sized LNG terminals. Short of economically devastating demand destruction, it is easy to imagine escalating gas prices over time. We know that the Gulf of Mexico's contribution to our gas supply has most likely peaked, as has Canada's. Likewise, the most productive conventional plays in currently accessible areas of the U.S. have been largely exploited. So in a very real sense, the most severe restricted-supply scenario is not an option.

RESPONSES OF PAUL KOONCE TO QUESTIONS FROM SENATOR BINGAMAN

Question 1. Coastal Zone Management Act amendments—The Department of Commerce (NOAA) has proposed a rule that would limit the time for appeals to the Secretary of Commerce of state consistency review determinations. Does this proposal address your concerns about Coastal Zone Management Act appeals?

Answer. The proposed rule does not fully address INGAA's concerns about the Coastal Zone Management Act appellate process, and in fact, NOAA's interpretation of the scope of its authority as part of this process gives rise to a number of additional concerns on the part of INGAA. INGAA outlined its concerns with the proposed rule in a filing at the Department of Commerce last August, and we would respectfully request that these comments be included in the record following these questions and answers.

One of the central issues INGAA has with the Coastal Zone Management Act appeals process is something that only Congress can fix. Section 319 of the CZMA currently provides the Secretary of Commerce 90 days within which to make a decision on an appeal, *once the record is closed*. The Secretary may extend this period for 45 additional days, but must make a decision at that point. The practical problem with the current scheme is that the statutory deadlines for action apply only after the record in the appeal is closed. The experience has been that the "record" in such appeals often has been permitted to remain open for months, and even years. In one recent appeal involving an interstate pipeline, the Secretary took 18 months to render a decision. This is an entirely unreasonable amount of time in which to decide what is, after all, an appeal of an earlier state consistency determination. The comprehensive energy legislation before the Senate (S. 2095) addresses this issue, by giving the Secretary clear timeframes in which to both close the record and issue a decision.

RESIDENTIAL NATURAL GAS CONSUMER IMPACT

Question 2. How does Dominion assure that the commodity portion of its natural gas bills is as low as possible?

Answer. It has been and continues to be the policy of the Dominion natural gas distribution companies (Dominion East Ohio, Dominion Peoples and Dominion Hope) to manage gas purchasing activities to achieve the lowest overall cost consistent with the provision of reliable service over the long-term. Also, the Public Utility Commissions in Ohio, Pennsylvania and West Virginia are actively involved in the review and oversight of the purchasing activities and costs paid for gas supplies by gas distribution companies through ongoing proceedings and audits. These Commissions do not permit recovery of gas supply costs unless the companies have demonstrated that they are acquiring supplies in a prudent manner.

Question 2a. How do you help your retail gas consumers cope with higher energy bills?

Answer. Dominion offers customers a budget payment plan under which customers can pay a fixed budget amount each month, offers other payment plans to reduce arrearages, and provides customers with energy conservation information. Dominion also encourages eligible customers to participate in government assistance programs, such as the Customer Assistance Program (CAP) and Percent of Income Payment Plan (PIPP), and contributes to weatherization assistance and hardship funds. The Company sends out press releases advising customers of the various programs that are available as well as cost saving conservation tips. Such information is also available on the company's Web site: *www.dom.com*, In addition, Dominion actively supports the customer choice programs in its service territories, which allow customers to shop around for other energy supplier offers.

Question 2b. Have you found that the number of customers who are unable to pay their bills has increased over the past few years? By how much?

Answer. Key metrics measured by Customer Credit Services, show a declining trend each year from 2001 to 2003, regarding the number of gas customer bankruptcies, the average arrears per gas customer and the percentage 120 day arrears dollars compared to total arrears.

Question 2c. LIHEAP assistance typically goes to households with incomes less than $10,000/year. Are you finding that households with higher incomes are also struggling to pay their bills?

Answer. There are many older adults and working poor having difficulty paying their bills, and the company makes every effort to provide them with assistance. Dominion donates shareholder dollars to hardship funds in its respective states and promotes customer and employee donations that are matched with the shareholder funds. The hardship funds have higher income limits to provide help to many of the households that are not eligible for LIHEAP.

Question 2d. With high natural gas prices reaching a new plateau, should funding for LIHEAP also increase?

Answer. Yes. Dominion works with the American Gas Association and the National Fuel Funds Network to support increased funding for LIHEAP. The company promotes LIHEAP in all of its states and conducts outreach campaigns to encourage eligible customers to apply for help.

RESPONSES OF PAUL KOONCE TO QUESTIONS FROM SENATOR FEINSTEIN

Question 1. The Energy Information Administration recently issued a report analyzing the Energy Bill, particularly as it relates to natural gas and gasoline production, consumption, and prices. My reading of the analysis is that the energy bill does nothing to decrease petroleum or natural gas consumption, does nothing to reduce petroleum imports, nor does it reduce the price of natural gas by 2010.

Can any of the witnesses explain to me why the federal government should spend at least $14 billion on a bill that purports to alleviate our natural gas problems and reduce our dependence on foreign oil when in fact ETA's numbers show that neither of these goals will be accomplished?

Answer. The February, 2004 EIA report, done at the request of Senator Sununu, was limited to just five specific tax provisions of the bill, so it is difficult to agree with the premise of the question that the bill does nothing to reduce our dependence on foreign oil or reduce natural gas prices. In fact, one very bright spot in the report is ETA's conclusion that extension of the Section 29 tax credit for the production of natural gas from unconventional sources would indeed benefit consumers. Specifically, EIA found that extension of the credit would:

- Increase total domestic natural gas production from unconventional resources;
- Continue to have a positive impact on production beyond the reference case due to the reserve additions brought on by the credit;
- Reduce average wellhead prices by almost $0.15 per thousand cubic feet over the 2005 to 2010 period;
- Increase the number of unconventional gas wells drilled by 20% over the 2004-2006 time frame when new qualifying wells could be drilled;
- Increase total unconventional gas reserves by 13% over the reference case for the years 2004-1006;

When the EIA estimate of a $0.15 per thousand cubic feet reduction in wellhead prices is held up against projected natural gas consumption during that same period of time, that reduction would result in consumer savings of over $10 billion, according to the Gas Technology Institute. This represents a benefit/cost ratio of more than 3 to 1 for that one provision.

With regard to EIA's analysis of the tax credit for new advanced nuclear power facilities, the Nuclear Energy Institute (NEI) has pointed out several key flaws in their conclusion that the credit will not spur additional nuclear plants beyond those eligible to receive the credit. The central criticism of the analysis is the assumption that capital costs for new plants will not decrease as new units are built. I've attached for the record a more detailed response prepared by NEI.

Question 2. Natural gas is the fuel of choice in California. The benefits of natural gas are well known. However, natural gas supplies are tight and costs of the gas have risen. The renewable fuels standard that is in the Energy Bill will increase ethanol production by approximately 2 billion gallons over the next 10 years.

In order to get those ethanol plants sited, they will have to be powered by natural gas. How much natural gas will be used by these plants? What will the price impact be on natural gas?

Answer. While Dominion is unable to quantify the amount of natural gas expected to be used by future ethanol plants, we do believe that the growing reliance on natural gas in many sectors of the U.S. economy is driving up the price of the commodity. Without a policy shift toward new nuclear and coal-fired power generation, accompanied by improved access to where our remaining natural gas resources are located, such as the Outer Continental Shelf and the Rocky Mountain regions, natural gas prices will remain significantly higher than historic levels.

GASOLINE PRICES

Question 3. On Monday, March 1, the Energy Information Agency released its weekly retail gasoline prices report. Across the country, gas prices have risen an average of 16 cents since mid-January. In California, the numbers are even more startling. The overall average of California's reformulated gasoline rose from $1.71 on January 12 to $2.16 on March 1.

At the same time, California's refineries are switching from winter blends to summer blends. And all of our reformulated gasoline must have ethanol in it since the state banned MTBE as of January 1, 2004.

- Why are gas supplies so limited in California?
- What will the effect of the closure of the Shell Bakersfield facility be on California's gasoline supply?
- What can be done to increase supply to California?
- What is the impact of the 2% ethanol requirement on California's gasoline supply?
- What is the long-term outlook for California's gasoline supply and prices?

Answer. Dominion does not refine nor market gasoline and is therefore not in a position to answer questions on gasoline price trends and influences.

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA,
Washington, DC, August 25, 2003.

Mr. DAVID KAISER,
Federal Consistency Coordinator, Coastal Programs Division, Office of Ocean and Coastal Resource Management, NOAA, Silver Spring, MD.

Re: Coastal Zone Management Act Federal Consistency Regulations; Docket No. 030604145-3145-01

DEAR MR. KAISER: Pursuant to the proposed rule issued in the referenced proceeding on June 11, 2003,[2] the Interstate Natural Gas Association of America (INGAA) submits the following comments on the National Oceanic and Atmospheric Administration's (NOAA) proposal to revise the Federal Consistency regulations promulgated under the Coastal Zone Management Act of 1972 (CZMA).

INGAA is a trade organization that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry in North America. INGAA represents virtually all of the interstate natural gas transmission pipeline companies operating in the United States, as well as comparable companies in Canada and Mexico. Its members transport over 95 percent of the nation's natural gas through a network of 180,000 miles of pipelines. Interstate natural gas pipelines are certificated by the Federal Energy Regulatory Commission (FERC) under section 7(c) of the Natural Gas Act (NGA).

On June 11, 2003, NOAA issued a proposed rulemaking to "make improvements to the Federal Consistency regulations to clarify some sections and *provide transparency and predictability to the Federal Consistency regulations*" (emphasis added). This rulemaking, in part, responds to Vice President Cheney's May 2001 National Energy Policy Report to the President (Energy Report), which specifically recommended that the President direct the Secretary of Commerce to reexamine current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding siting of energy facilities in the coastal zone.

The preamble to the proposed rule focuses on how the Federal Consistency regulations affect oil and gas lease sales. While this focus is understandable in view of the Energy Report's specific mention of the Outer Continental Shelf Lands Act in connection with the CZMA, it still is remarkable that the preamble fails even to acknowledge the growing conflict between NOAA's interpretation of its CZMA authority and the FERC's authority under the NGA to issue certificates of public convenience and necessity for interstate natural gas pipelines. This omission is particularly glaring given that appeals to NOAA by two interstate pipelines from state objections to consistency certifications were pending when the proposed rule was issued.[3]

Some of the proposed changes to NOAA's regulations represent incremental improvements over the current rules affecting interstate pipelines and, as will be detailed herein, INGAA supports these modifications. Still, NOAA's failure to acknowledge and address the larger conflict means that, with respect to interstate pipeline construction, the rulemaking will not achieve its stated goal of providing "transparency and predictability to the Federal Consistency regulations."

The NGA, which predates the CZMA by decades, confers on FERC plenary authority to issue certificates of public convenience and necessity authorize the siting, construction and operation of interstate natural gas pipelines. The Congress in 1972 made clear that enactment of the CZMA did not diminish, modify or supersede this preexisting federal authority. Now, however, the pending appeals from state objections to consistency certifications for proposed interstate pipelines that have received FERC certificates calls into question whether this clear statement by the Congress will be followed. INGAA urges NOAA in its final rule to state clearly that it will give due weight to FERC's findings in view of the statutory scheme in the NGA that confers on FERC sole responsibility for determining whether, and under what conditions, a proposed interstate pipeline is required by the public convenience and necessity.[4]

A final rule in this proceeding will be legally deficient should it not address the specific legal issues and practical circumstances surrounding NOAA's administration of the CZMA and interstate natural gas pipelines that receive FERC certificates under the NGA. In the alternative, should NOAA not address these issues in the final rule, INGAA requests that NOAA initiate a separate, new rulemaking focused on these issues. In particular, such a rulemaking should propose amending NOAA's Consistency Regulations to: (1) require as a condition for approval of a state Coastal

[2] 68 Fed. Reg. 34851 (June 11, 2003).
[3] Millennium Pipeline Company and Islander East Pipeline Company, L.L.C.
[4] *See* ERC Comments on Millennium Consistency Appeal, November 15, 2002. at page 2.

Management Program that the state participate in FERC's National Environmental Policy Act (NEPA) review process for a pipeline certificate application to ensure that the FERC has an opportunity to address the state's concerns as part of that process; and (2) adopt the record of the FERC certificate proceeding as the record for any appeal from a state's objection to a pipeline applicant's consistency certification in order to avoid the delays and legal infirmities associated with relitigating FERC's determination of issues reserved solely to FERC under the NGA.

INGAA submits that the proposed rule is legally deficient due to NOAA's mischaracterization of its legal authority under the CZMA as it applies to interstate natural gas pipeline projects that have been authorized by the FERC pursuant to the NGA.

The Federal Consistency Process Does Not Affect a Waiver of FERC's Plenary NGA Authority.

NOAA asserts that Federal Consistency is a "limited waiver of Federal Supremacy and authority" (68 Fed. Reg. 34852, June 11, 2003). The Congress in the NGA, however, conferred on the FERC plenary authority to authorize the construction of interstate natural gas pipelines. NGA Section 1(a) states unequivocally that transportation for ultimate distribution to the public is "affected with a public interest", and that Federal regulation in matters relating to transportation in interstate commerce "is necessary in the public interest". Numerous Supreme Court decisions validate the preemptive effect of FERC's authority under the NGA.[5] By contrast, Congress limited CZMA's construction with other statutes not to "diminish either federal or state jurisdiction . . ." 16 U.S.C. Sec. 1456(e).

NOAA's and/or Delegated State Authority's Consideration of Alternatives Subverts the Comprehensive Scheme for Interstate Natural Gas Pipeline Authorization Under the NGA.

The NGA and NEPA require FERC to assess all reasonable alternatives to a pipeline's construction proposal as a key factor in its evaluation and determination. Yet NOAA asserts that it must review alternatives that the protesting coastal state, *in that state's judgment*, deems consistent with its state coastal management plan. (68 Fed. Reg. 34858). This subverts the comprehensive federal scheme Congress intended for interstate pipeline analysis.

State consideration of issues not already covered in the FERC's Environmental Impact Statement (EIS) should, at the very least, be done within the FERC-imposed deadline for State agency comments. This would continue to allow for full State participation, while protecting federal authority to authorize interstate natural gas pipeline construction pursuant to the NGA.

The Scope of Appellate Review Under the CZMA is Limited.

NOAA asserts that it has *de novo* review authority (68 Fed. Reg. 34859) pursuant to the CZMA, without citation to the statute. Absent an express statutory grant of authority for *de novo* review, however, NOAA's authority under CZMA is appellate only. 16 U.S.C. Sec. 1456(c)(3)(a). It is black letter law that an "appeal" is an examination by the appropriate review body of a decision record to determine if there are material errors of fact or application of law contained in that record. Therefore, NOAA lacks the authority to engage in a de novo review of the interstate pipeline routing alternatives considered by the FERC in the NGA certificate process.

NOAA in the preamble attempts to clarify its use of the term de novo review:

> The Secretary's review is de novo, to determine if the project is consistent with the CZMA or in the interest of national security. It is not a review of the basis for the State's objection or the basis for issuing the Federal agency authorization. The Secretary does not substitute the Secretary's judgement [sic] for that of the authorizing Federal agency regarding the merits of the project, nor does the Secretary determine whether a proposed project complies with other Federal law. (68 Fed. Reg. 34863).

While INGAA does not object to this particular characterization of review authority under the CZMA, the statement fails to address the fact that in considering alternative routes for an interstate pipeline that has been certificated by the FERC, NOAA is engaging in what amounts to the very form of de novo review that it disclaims in the cited statement.

NOAA also asserts that "*through the CZMA Congress gave the States the ability to review, federal actions, independent of the Federal agencies' reviews.*" (68 Fed.

[5] *See, e.g., Schneidewind* v. *ANR Pipeline Co.*, 485 U.S. 293 (1988); *National Fuel Gas Supply Corp.* v. *Public Service Commission of the State of New York*. 894 F.2d 571 (2nd Cir.), *cert. denied*, 497 U.S. 1004 (1990).

Reg. 34860) (emphasis added). This statement, however, is inconsistent with the fact that the CZMA limits NOAA's consistency review of a federal permit activity to an examination of whether the proposed activity is *consistent to the maximum extent practicable* with the *enforceable policies* of a state's coastal zone management plan. A state policy in its coastal zone management plan that has the effect of blocking the siting of an interstate pipeline could not be enforceable against a federally preemptive NGA.

A Final Rule That Fails to Address the Conflict Between NOAA's Interpretation of its CZMA Authority and The NGA Would Not be Reasoned Decisionmaking.

NOAA asserts that its regulations are designed to provide "reliable procedures and predictability" to the implementation of Federal consistency. (68 FedReg. 34851-52). In the case of interstate gas pipeline construction, NOAA's procedures throw into complete disarray FERC's long-standing procedures for its analysis and determination under the NGA, NEPA, and the Administrative Procedure Act, and materially diminish the predictability of FERC's preemptive certificate determinations.

COMMENTS ON THE PROPOSED RULE

INGAA appreciates NOAA's proposals to improve its Consistency Regulations by specifying deadlines for action by the states and by NOAA itself. Still, INGAA suggests that, at least within the context of interstate pipeline projects that are subject to the FERC certificate process under the NGA, even more expedited regulations can be adopted.

In particular, proposed section 930.130 states that one of the three circumstances when the 270-day period for closing the decision record can be stayed is when the Secretary needs additional NEPA and/or ESA documents. This exception makes little sense in the case of an appeal that has been filed following the FERC's issuance of a certificate of public convenience and necessity for an interstate pipeline. The record of the certificate proceeding will include all necessary NEPA and/or Endangered Species Act documents; therefore, there is no need for a stay in this instance.

In fact, given the comprehensive nature of the record in a FERC certificate proceeding, it can be asked validly whether, in this context, there is the need for NOAA to develop a separate record for purposes of the appeal. The FERC record will address the two threshold questions that are relevant in the Secretarial review process under the CZMA: whether the proposed activity is consistent with the objectives of the CZMA or otherwise necessary in the interest of national security.

With regard to this second criteria, NOAA's regulations at section 930.121 require that an activity must "significantly or substantially" further the national interest before the Secretary can override an objection based on the statutory "national interest" criteria. INGAA submits that FERC's issuance of a certificate of public convenience and necessity for an interstate pipeline should by definition be deemed to meet the criteria that an activity significantly and substantially furthers the national interest. A FERC certificate confers on its holder the ability to exercise a federal right of eminent domain. The fact that the Congress in the NGA saw fit to confer this right on a private applicant acting pursuant to a federal authorization speaks volumes about the national interest furthered by interstate pipeline projects with FERC certificates.

Finally, given the comprehensive nature of the record in the FERC certificate proceeding, INGAA questions whether the 270-day record closing period and the 90-day period for decision are necessary in this context. Together, these two periods total close to a full year, when all that is really needed is a period for briefing and for NOAA to deliberate on the briefs and the record that already is complete as a result of the FERC certificate process. INGAA requests that, in cases where the FERC certificate already has been issued when an appeal is filed, the combined period be reduced to 120 days. That is, 30 days for briefing and 90 days for deliberation.

Thank you in advance for your consideration of INGAA's comments.

DONALD F. SANTA, JR.,
President.

THE ENERGY INFORMATION ADMINISTRATION'S ANALYSIS OF NEW NUCLEAR POWER PLANTS: MYTHS AND FACTS

PREPARED BY THE NUCLEAR ENERGY INSTITUTE

MYTH: In a recent report prepared at the request of Sen. John Sununu (R-NH), the Energy Information Administration (EIA) analyzed the impact of various tax-related incentives in the conference report on H.R. 6. That legislation includes a production tax credit of $18 per megawatt-hour for the first eight years of operation for the first 6;000 megawatts of new nuclear generating capacity built in the United States. The EIA report (SR/OIAF/2004-02) concluded that the production tax credit would, in fact, stimulate construction of 6,000 megawatts of new nuclear power capacity, but that further expansion beyond 6,000 megawatts would not occur because new nuclear plants would still not be economic.

FACT: The EIA analysis is incorrect, because EIA used unrealistically inflated assumptions about the capital cost of new nuclear power plants in the analysis performed for Sen. Sununu and in its *Annual Energy Outlook 2004* forecast. EIA assumed a capital cost of $1,928 per kilowatt of capacity for new nuclear capacity. Credible industry estimates show that the capital cost for the first few nuclear power plants will be in the range of $1,300-$1,400 per kilowatt. As more plants are built, capital costs will decline to the $1,000-$1,100 per kilowatt range. At this capital cost, new nuclear plants will be clearly competitive with other sources of baseload electricity.

FACT: The $18-per-megawatt-hour production tax credit provided in the conference report on H.R. 6 represents a substantial incentive for construction of new nuclear plants. The tax credit will allow companies to assume the investment risks and licensing risks associated with building the first few new nuclear plants under a new licensing process that is essentially untested.

FACT: Once the first few new plants are built with the stimulus provided by the tax credit, companies will be satisfied that they can manage the licensing and investment risks and will build significant numbers of new plants without government assistance. In a report (*Nuclear Power's Role in Meeting Environmental Requirements*) published in 2003, the Electric Power Research Institute used the EIA's own model to forecast the amount of new capacity that would be built using more reasonable capital cost assumptions than EIA. The result: At $1250 per kilowatt, 23,000 megawatts of new nuclear capacity would be built by 2020. At $1,125 per kilowatt, 62,000 megawatts of new nuclear capacity would be built by 2020.

FACT: In its own *Annual Energy Outlook 2004*, EIA explored an alternative to its high-capitalcost base case. If the capital cost of new nuclear power plants falls to $1,081 per kilowatt by 2019. EIA projects that about 26,000 megawatts of new nuclear capacity would be built by 2025 (*Annual Energy Outlook 2004*, page 58). Since nuclear power plants have lower operating costs than all other forms of electricity generation, EIA found: "If the $1,081 per kilowatt estimate could be realized [as the industry expects], it is possible that *nuclear power could eventually be used to satisfy virtually all the baseload demand in the United States in future years.*" (Emphasis added.)

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