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Preface

The Energy Information Administration (EIA) prepares the *Short-Term Energy Outlook* (energy supply, demand, and price projections) monthly for distribution on the internet at: www.eia.doe.gov/steo**.** In addition, printed versions of the report are available twice annually in April and October.

The forecast period for this issue of the *Outlook* extends from October 2000 through December 2001. Data values for the third quarter 2000, however, are preliminary EIA estimates (for example, some monthly values for petroleum supply and disposition are derived in part from weekly data reported in EIA's *Weekly Petroleum Status Report*) or are calculated from model simulations that use the latest exogenous information available (for example, electricity sales and generation are simulated by using actual weather data). The historical energy data, compiled in the October 2000 version of the Short-Term Integrated Forecasting System (STIFS) database, are mostly EIA data regularly published in the *Monthly Energy Review*, *Petroleum Supply Monthly*, and other EIA publications. Minor discrepancies between the data in these publications and the historical data in this *Outlook* are due to independent rounding. One exception to this is that recent petroleum demand and supply data displayed in this report reflect the incorporation of resubmissions of the data as reported in EIA's *Petroleum Supply Monthly*, Table C1.

The STIFS model is driven principally by three sets of assumptions or inputs: estimates of key macroeconomic variables, world oil price assumptions, and assumptions about the severity of weather. Macroeconomic estimates are produced by DRI/McGraw-Hill but are adjusted by EIA to reflect EIA assumptions about the world price of crude oil, energy product prices, and other assumptions which may affect the macroeconomic outlook. By varying the assumptions, alternative cases are produced by using the STIFS model.

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Highlights

West Texas Intermediate Price Falls Following SPR Announcement

WTI Prices are now estimated to have averaged $33.60 per barrel for the month of September, well below the inflated daily averages (between $37 and $38 per barrel) reached prior to the Clinton Administration's announcement of a limited drawdown of the Strategic Petroleum Reserve on September 22. EIA estimates that the SPR drawdown will make an additional 10 million barrels of crude oil available to the United States for replenishing crude oil stocks or for processing into refined products between now and the end of the year.

Consumers to Pay More for Heating Oil This Winter

U.S. residential heating oil prices averaged an estimated $1.34 per gallon in September, approximately 44 cents per gallon above the price in September 1999. Gradually declining crude oil prices and winter weather patterns close to normal conditions may limit additional increases through the winter peak demand period to as little as 4 cents per gallon (base case). Base case conditions would be expected to yield average winter retail prices of $1.36 per gallon, compared to $1.18 per gallon last winter. Year-over-year increases would be particularly significant in Q4 2000.

Natural Gas Prices High Due to Supply Tightness

Average wellhead prices for natural gas are estimated to have averaged between $4.60 and $4.70 per thousand cubic feet in September, nearly double the price from one year ago. The year-over-year differential is likely to widen by yearend. Although rising crude oil prices have encouraged natural gas prices to advance, the primary cause of these elevated gas prices has been the delicate supply situation. U.S. working gas in storage is estimated to be about 9 percent below normal and about 12 percent below the year-ago level. Increases in gas production this year have been minimal, and in any case have failed to keep pace with demand.

Winter Electricity Demand to be Up From Last Year's Level

This winter's heating degree-days (HDD) are assumed to be 11 percent above last winter's HDD, which were well below normal. This winter, total electricity demand is expected to be about 2.6 percent above the year-ago level under normal weather assumptions, driven by increased demand in the residential and commercial sectors, which are each expected to post growth of 3.5 to 4.0 percent .

Table HL1. U. S. Energy Supply and Demand

	Year				Annual Percentage Change		
	1998	1999	2000	2001	1998-1999	1999-2000	2000-2001
Real Gross Domestic Product (GDP)							
(billion chained 1996 dollars)	**8516**	**8876**	*9341*	*9696*	**4.2**	*5.2*	*3.8*
Imported Crude Oil Price [a]							
(nominal dollars per barrel)........................	**12.08**	**17.21**	*27.86*	*24.58*	**42.5**	*61.9*	*-11.8*
Petroleum Supply (million barrels per day)							
Crude Oil Production [b]	**6.25**	**5.88**	*5.84*	*5.91*	**-5.9**	*-0.7*	*1.2*
Total Petroleum Net Imports							
(including SPR)	**9.76**	**9.91**	*10.12*	*10.75*	**1.5**	*2.1*	*6.2*
Energy Demand							
World Petroleum							
(million barrels per day).............................	**73.6**	**74.8**	*75.9*	*77.9*	**1.6**	*1.5*	*2.6*
Petroleum							
(million barrels per day).............................	**18.92**	**19.52**	*19.58*	*20.00*	**3.2**	*0.3*	*2.1*
Natural Gas							
(trillion cubic feet)	**21.26**	**21.36**	*22.22*	*22.82*	**0.5**	*4.0*	*2.7*
Coal [c]							
(million short tons)	**1039**	**1039**	*1065*	*1090*	**0.0**	*2.5*	*2.3*
Electricity (billion kilowatthours)							
Utility Sales [d]	**3240**	**3296**	*3366*	*3430*	**1.7**	*2.1*	*1.9*
Nonutility/Sales [e]	**156**	**173**	*189*	*191*	**10.9**	*9.2*	*1.1*
Total	**3396**	**3469**	*3555*	*3621*	**2.1**	*2.5*	*1.9*
Total Energy Demand [f]							
(quadrillion Btu)..	**94.4**	**96.3**	*97.8*	*99.6*	**2.0**	*1.6*	*1.8*
Total Energy Demand per Dollar of GDP							
(thousand Btu per 1996 Dollar)	**11.09**	**10.85**	*10.47*	*10.27*	**-2.2**	*-3.5*	*-1.9*
Renewable Energy as Percent of Total [g] ...	**7.0**	**7.0**	*6.7*	*6.6*			

[a]Refers to the refiner acquisition cost (RAC) of imported crude oil.

[b]Includes lease condensate.

[c]Total Demand includes estimated Independent Power Producer (IPP) coal consumption.

[d]Total annual electric utility sales for historical periods are initially derived from the sum of monthly sales figures based on submissions by electric utilities of Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions." Final annual totals are taken from compilations from Form EIA -861, ":Annual Electric Utility Report."

[e]Defined as the difference between total nonutility electricity generation and sales to electric utilities by nonutility generators, reported on Form EIA-867, "Annual Nonutility Power Producer Report." Data for 1999 are estimates.

[f]The conversion from physical units to Btu is calculated by using a subset of conversion factors used in the calculations performed for gross energy consumption in Energy Information Administration, *Monthly Energy Review* (*MER*). Consequently, the historical data may not precisely match those published in the *MER* or the *Annual Energy Review (AER)*.

[g]Renewable energy includes minor components of non-marketed renewable energy, which is renewable energy that is neither bought nor sold, either directly or indirectly, as inputs to marketed energy. The Energy Information Administration does not estimate or project total consumption of non-marketed renewable energy.

SPR: Strategic Petroleum Reserve.

Notes: Minor discrepancies with other published EIA historical data are due to independent rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Latest data available from Bureau of Economic Analysis and Energy Information Administration; latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109; *Petroleum Supply Annual*, DOE/EIA-0340/2; *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; and *Quarterly Coal Report*, DOE/EIA-0121; *International Petroleum Statistics Report* DOE/EIA-0520; *Weekly Petroleum Status Report,* DOE/EIA-0208. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0900.

Winter Fuels Outlook: 2000-2001

Introduction

This winter--defined as the period from October 2000 to March 2001--is expected to bring with it significantly higher heating bills than those seen last winter. The main reasons for this outcome are: 1) expected space-heating fuels requirements larger than those of last winter, the warmest on record; 2) inventories of key heating fuels--especially heating oil--below normal and substantially below those of the outset of the winter of 1999-2000, and 3) crude-oil prices at relatively high levels. Because of the brisk recovery of Asian economies and continued robust growth in the U.S., neither the production increases announced by OPEC since last winter nor efforts by non-OPEC sources to increase output have been able to stem the increase in crude oil prices. Although they have declined somewhat since their recent peaks and are expected to continue to ease during the winter season, world oil prices are still expected to be the highest of any since the end of the Gulf War. As a result, retail energy fuel costs--already quite high by recent historical standards--will remain high amid tight supply conditions, posing increased risks of short-term price spikes similar to those of the previous winter. In contrast to the 1999-2000 winter season, natural-gas households are likely to see the largest year-over-year percentage increases in fuel bills of any heating fuel.

Overview

Heating fuel markets are expected to start the season with much higher prices and (generally) lower inventories than at this time last year. Moreover, the assumption of "normal" weather, which is almost 12 percent more severe in terms of heating degree-days than that of the previous winter--the warmest on record--is expected to raise demand for space-heating fuels. The resultant tight supply/demand balance substantially increases the risk of price run-ups if very cold weather patterns emerge, even if only temporarily. In contrast to those of previous winters, fuel market supplies cannot be described as adequate to ensure a high probability of supplies meeting the demands of a very cold winter without difficulty. High spot prices, reflecting the tight supplies, would be expected to engender "supply-side" responses, such as increased heating-oil supplies brought about by higher refinery utilization rates, distillate yields, and imports. Whether these responses would suffice to avoid sustained price run-ups in the event of very cold weather is not known at this time. Warmer-than-normal weather in the main heating regions of the United States would obviously ease demand pressures, but the probability of such an outcome is no more likely than that of a colder-than-normal winter.

The impact of a colder-than-normal winter on fuel prices and consumer bills has therefore become particularly difficult this year and subject to much higher uncertainty than in past years. A sustained cold-weather scenario for this winter could result in average upward price responses much larger than any downward price reactions to a very warm winter scenario. Current constraints on available supplies would tend to hamper responses to cold weather, resulting in large price adjustments but limited additional supply, at least in the short term. Because the probability of a sustained cold winter is low, such a scenario should be viewed as unlikely but carries with it the potential for large upward price shocks. Short-term price spikes resulting from brief cold weather snaps, such as those that occurred during the first quarter of this year, are also possible.

Heating Bills

Table WF01 below summarizes historical and base-case (normal weather) demand, total expenditure, and price projections for key heating fuels on a per-household basis. The calculations focus on particular regions of the country with respect to consumption and projected weather factors (i.e., changes in heating degree-days) but assume national average consumer prices for heating fuels normally presented in the *Short-Term Energy Outlook.* Thus, heating bill calculations are illustrative of the magnitude of the expected changes in fuel bills but are not necessarily indicative of the absolute expenditure levels to be anticipated by individual consumers.

Table WF01. Illustrative Consumer Prices* and Expenditures for Heating Fuels During the Winter**

	1997-1998 Actual	1998-1999 Actual	1999-2000 Actual	2000-2001 Base Forecast
Natural Gas (Midwest)				
Consumption (mcf)	82.4	84.5	81.7	90.9
Avg. Price ($/mcf)	6.56	6.27	6.61	8.58
Expenditures ($)	541	530	540	780
Heating Oil (Northeast)				
Consumption (gals)	636	650	644	693
Avg. Price ($/gal)	0.92	0.80	1.18	1.37
Expenditures ($)	585	520	760	949
Propane (Midwest)				
Consumption (gals)	814	835	807	898
Avg. Price ($/gal)	0.94	0.85	1.02	1.16
Expenditures ($)	765	710	823	1,045

* National average prices.
** Based on typical per-household consumption by region.

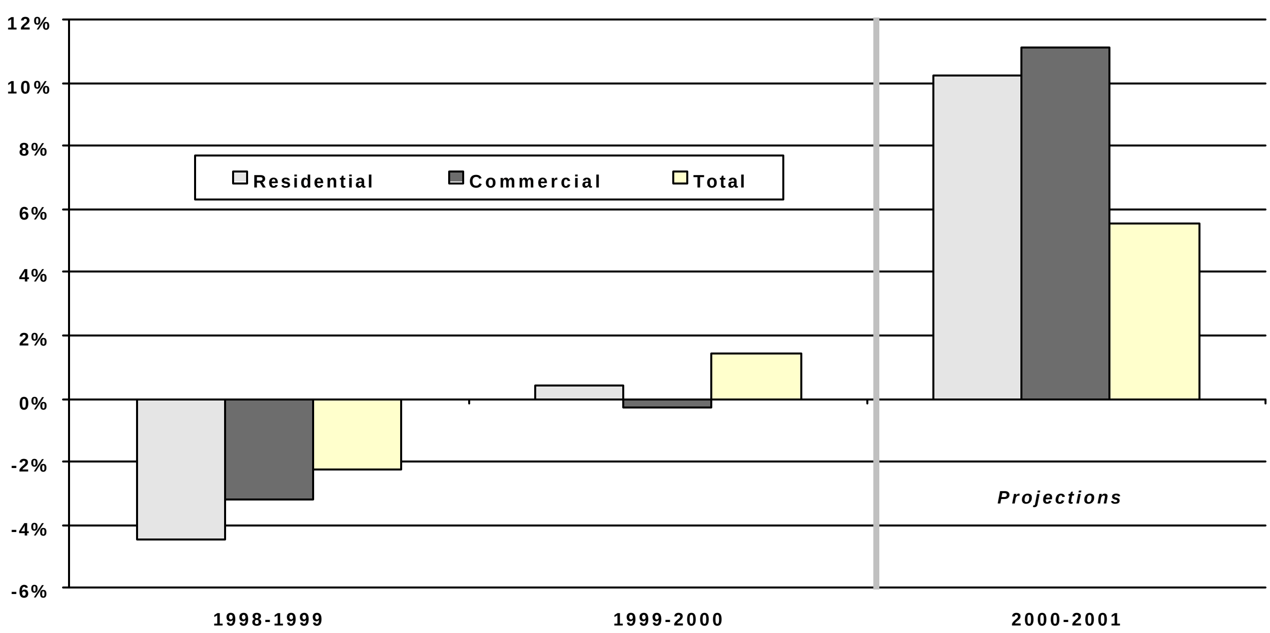
As Table WF01 above shows, expenditures for this winter are likely to be up substantially from those of last winter as a result of both higher demand and prices. In our base case-projections, the expenditure increases for households are: 25 percent for heating oil and propane; and 44 percent for natural gas. In a reversal of price behavior last winter, gas-heated households are likely to experience much higher percentage increases than those consuming other fuels. Weather in the major gas-consuming regions was as much as 18 percent warmer than normal last year compared to 12 percent for the lower 48 states as a whole. Thus, under normal weather circumstances, increases in per household gas consumption is expected to be relatively large. Also, since wellhead gas prices have been high most of the summer, substantial fuel cost adjustments for residential gas customers this winter are expected to be largely if not fully put in place by the nation's gas utilities. During the previous season, warmer-than-normal weather and lags in fuel cost adjustments mandated by regulations resulted in virtually no change in average expenditures for gas-heated households, compared to the 1998-99 winter heating season.

Natural Gas

Demand

Total natural gas demand is expected to average 71.2 billion cubic feet (bcf) per day, up 4.1 bcf per day (6.1 percent) over the level recorded last winter. Contributing to the growth in winter demand is an increase in gas space-heating customers (about 1 percent). The bulk of the winter-derived increase, however, stems from the assumption of normal weather. Milder weather last winter in the lower 48 states resulted in gas-weighted heating degree-days almost 12 percent warmer than normal, with several Midwestern areas recording weather as much as 18 percent warmer than normal. As a result, consumption this winter in residential and commercial markets is expected to average 21.0 and 12.5 bcf per day, respectively, up 10.5 percent and 10.6 percent from the previous winter's consumption (Figure WF1).

Figure WF1. U.S. Winter Natural Gas Demand
(Year-to-Year Percent Change)



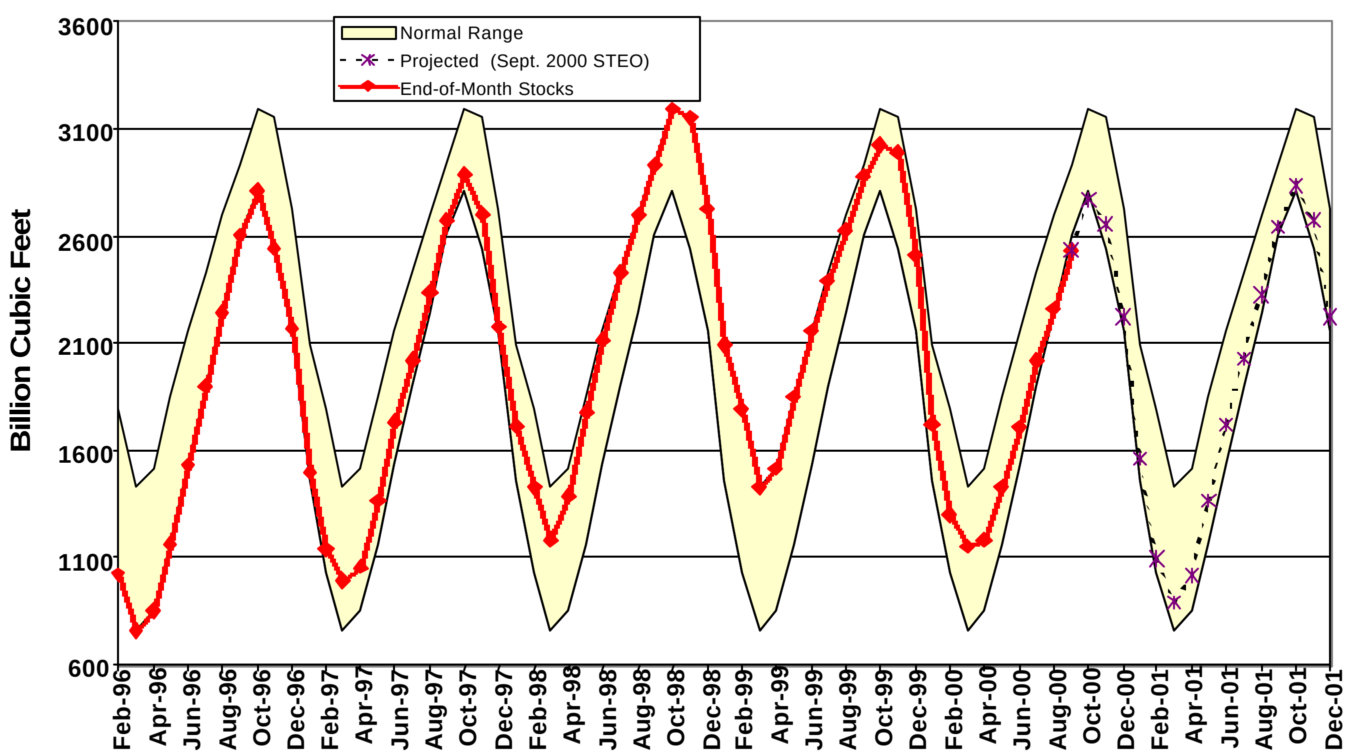
Supply

Domestic natural gas production is expected to average 51.8 bcf per day during the heating season, up slightly from the 50.7 bcf per day during the previous winter. Drilling activity for both oil and gas had dropped sharply in 1999 in reaction to the 1998 decline in the price of oil and natural gas. The rig count in 1999 averaged 625 compared to the previous high of 943 in 1997. But exploration activity accounts have increased sharply in 2000 along with the rise in the price of crude oil and natural gas. By mid-September, the rig count reached 1012, with 816, or 80 percent, of the rigs dedicated to gas exploration. But because of the lead time needed for production to respond to exploration activity, increases in production are expected to provide little of the projected demand increase for this winter.

Storage plays a critical role in meeting increased winter demand. Working gas inventories at the beginning of the heating-season (October 1) are estimated at 2,530 bcf, 227 bcf below the 5-year (1995-1999) average of 2,757 bcf (Figure WF2). The region most dependent on inventories is the East Consuming region, which contains 56 percent of available capacity. It accounts for 1,610 bcf., 107 bcf below the 5-year regional average. The region is estimated to have filled almost 88 percent its active storage capacity. Stocks in the West Consuming region, which contains 15 percent of active capacity, are estimated at 300 bcf, which is 57 bcf below the 5-year regional average. That region is estimated to have filled 60 percent of its working gas storage capacity. The Producing region, estimated at 620 bcf, is 85 bcf below the 5-year average. Because storage activity in this region is oriented of production operations and summer power-generation requirements, it does not serve as a prime source to satisfy heating-season demand. Most storage facilities are expected to continue to add to stocks in October, which have averaged 160 bcf in the previous 5 years.

During this heating season, withdrawals are expected to be 9.2 bcf per day, slightly less than last year's average of 9.5 bcf per day. Due to a lower level of working gas at the beginning of this heating season, end-of-season stocks of working gas are projected to be 857 bcf compared to 1,150 last year. This would be the lowest level since the 750 bcf level reached in March, 1996.

Figure WF2. Working Gas in Storage



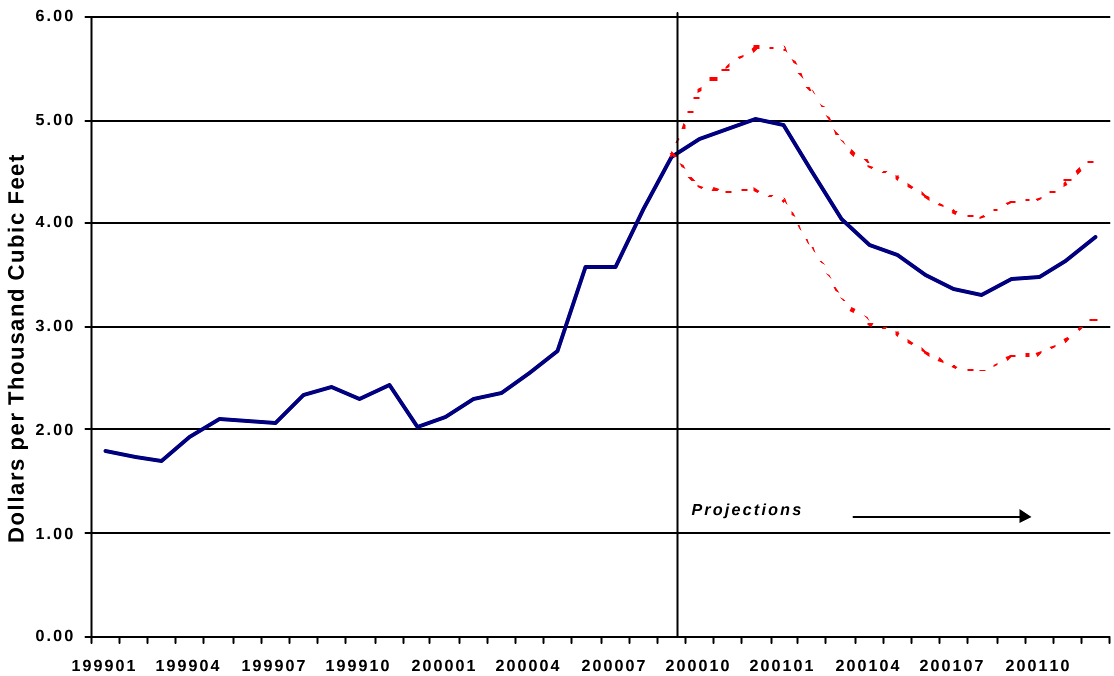
Natural gas net imports are expected to average 10.2 bcf per day, or 14 percent of demand, compared to last year's 9.6 bcf per day, or 12 percent of demand. During the winter months, net imports are about 10 percent higher than flows during the rest of the year and usually increase to full pipeline capacity. That capacity is scheduled to increase at the end of 2000 when the Alliance Pipeline will begin carrying gas from western Canada to the Midwest. Assuming that it will take several months before Alliance reaches its full capacity of 1.3 bcf per day, that pipeline may not fully contribute to advancing new gas supplies until the heating season is nearly over. Even if Alliance is near capacity at mid winter, it is likely that a substantial portion of the volumes contracted for delivery on the system will have been de-contracted from other systems, particularly TransCanada Pipeline System. Thus it is an important question as to just how significant Alliance will be with respect to net new supply from Canada.

Prices

Average spot prices for natural gas are estimated to have averaged between $4.90 and $5.00 per thousand cubic feet (mcf) in September, nearly double the price from one year ago (Figure WF3). Average natural gas wellhead prices (which reflect some short and longer-term contract prices) are projected to post an average of $4.48 per mcf this winter, also almost double the average recorded during the 1999-2000 season. Several factors account for this sharp increase, including: below-average stock levels resulting from lagging domestic production in the face of increasing demand from the strong U.S. economy (despite increases in drilling activity); increases in summer power-generation demand, which helped constrain inventory accumulations to half their normal rate; the influence of the rise in crude-oil prices on fuel switching and, hence, prices; and inventories of other winter fuels (notably heating oil) also being below average. It should be noted that mild winter weather as well as higher inventories depressed wellhead prices during the previous heating season, making the difference between the two years especially large.

Prices paid by residential consumers are also expected to move up sharply, averaging $8.58 per mcf, up 29.5 percent from last winter's average of $6.61. This is the largest percentage increase of the major space-heating fuels to the residential sector. Consumers could see higher or lower prices during the winter, depending on whether abnormally cold or warm conditions develop.

Figure WF3. Natural Gas Spot Prices: Base Case and 95% Confidence Interval



Heating Oil

Demand

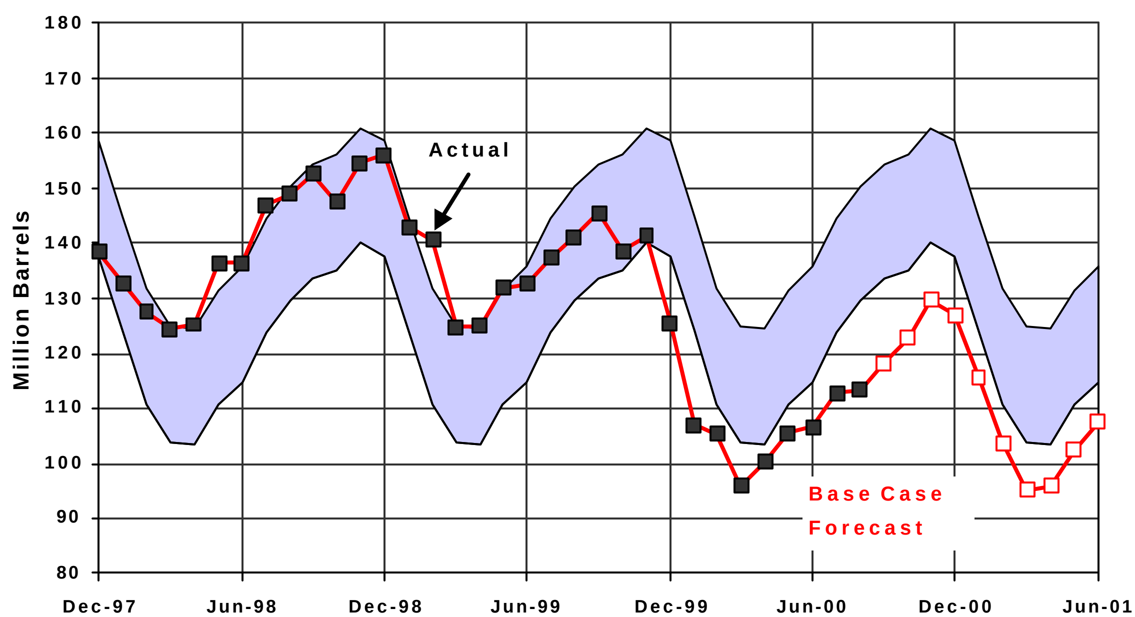
The base-case winter distillate fuel requirement is projected to be 3.88 million barrels per day, 130,000 barrels per day, or 3.3 percent, above last winter. The expectation of normal winter weather in the Northeast, the principal region for heating oil, would bring about an 8 percent increase in heating degree-days in that region and a corresponding increase in heating oil demand. Meanwhile, adding to the overall expected increases in distillate demand, growth in transportation-related demand is expected to continue at a strong pace.

Supply

The three sources of supply--domestic refinery production, net imports and primary stock withdrawals--should be adequate to meet the needs of a normal winter, assuming no extreme cold weather episodes or supply disruptions. As noted below, however, well above-normal spreads between distillate prices and crude oil costs are expected for the winter to help induce the necessary increment to supply to meet a normal or colder-than-normal winter in the United States. During this winter season, refinery production of distillate is projected to average 3.66 million barrels per day, up 270,000 barrels per day from the previous winter's production. That increase--more than twice that of total consumption—is expected to be brought about by three factors: 1) a 90,000 barrels-per-day increase in refinery capacity; 2) utilization rates averaging 91.8 percent compared to 89.2 percent last winter season (but still less than the 94.8 percent experienced during the 1997-98 winter season), and 3) an increase in average distillate yields to 23.7 percent from 22.9 percent last winter. Net imports are expected to average 110,000 barrels per day, or 2.8 percent of total winter requirements, slightly more than the 100,000 barrels-per-day average of the previous heating season. Maintaining this level of net imports is seen as achievable (in fact, much higher import levels have been seen in the past) but tight overall supplies elsewhere in the Atlantic Basin are likely to add to steep marginal acquisition costs.

Primary inventories of distillate at the beginning of this heating season are estimated at between 114 and 118 million barrels, down 15 percent to 18 percent from last year and below the normal range (Figure WF4). End-of-season (March 31) stocks are projected to be 95 million barrels, similar to the 96 million barrels per day available at the end of the previous heating season. That would be the lowest end-of-season stock level since the 89 million barrels recorded in March 1996. It should be noted that the projection excludes the newly created fuel oil reserve, projected to be 2 million barrels by early November. Not only are stock levels projected to be below the normal range for the entire winter season, but also the average stock withdrawal is therefore projected to be only 130,000 barrels-per-day--less than half that of the previous winter--due to the lower stock levels.

Figure WF4. U.S. Distillate Fuel Stocks



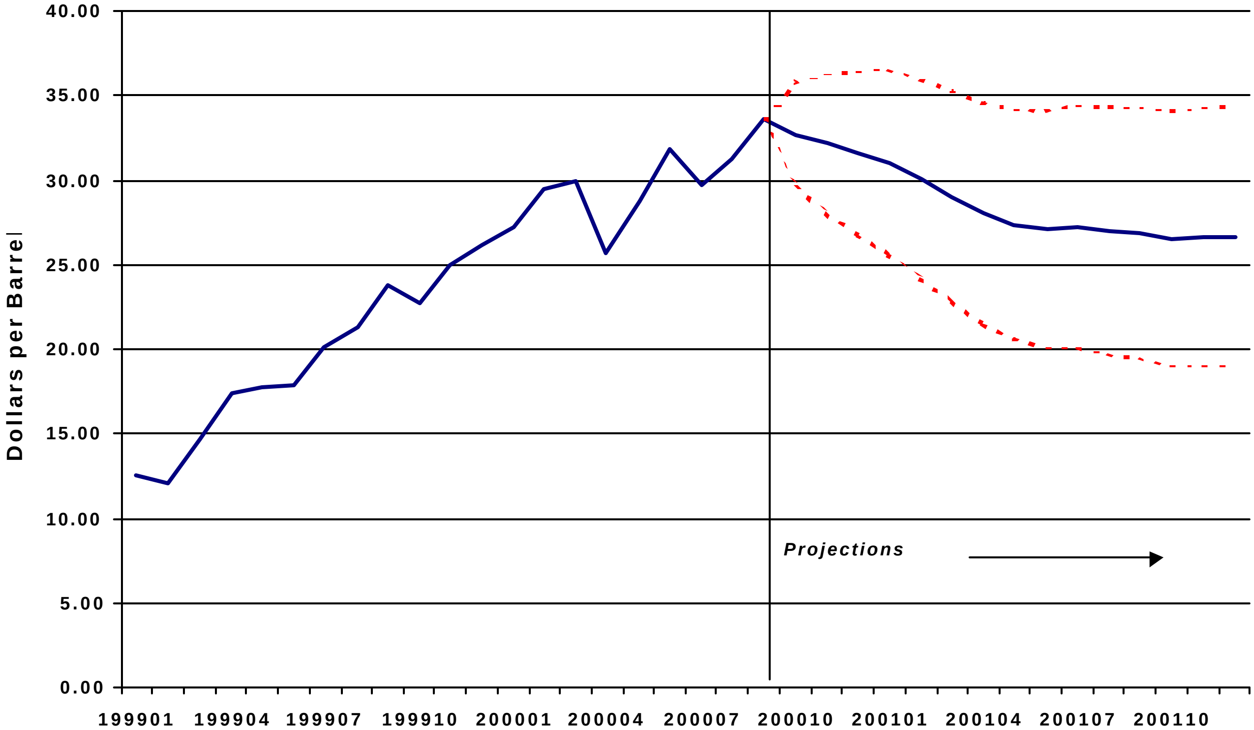
NOTE: Colored Band is Normal Stock Range

EIA estimates that average distillate stock levels this winter will be about 3 to 5 million barrels above where they would otherwise have been had the President not ordered a swap of 30 million barrels of oil from the Strategic Petroleum Reserve (SPR) this fall in exchange for future barrels (assumed here to be returned to the SPR during the second half of 2001). This assumes that the SPR release does not spur offsetting cutbacks from OPEC sources. The increment is small compared to total winter requirements but does improve the buffer against modest increases in demand above baseline levels and improves the likelihood that stocks will stay above the minimum levels seen in 1996 by season-end.

Prices

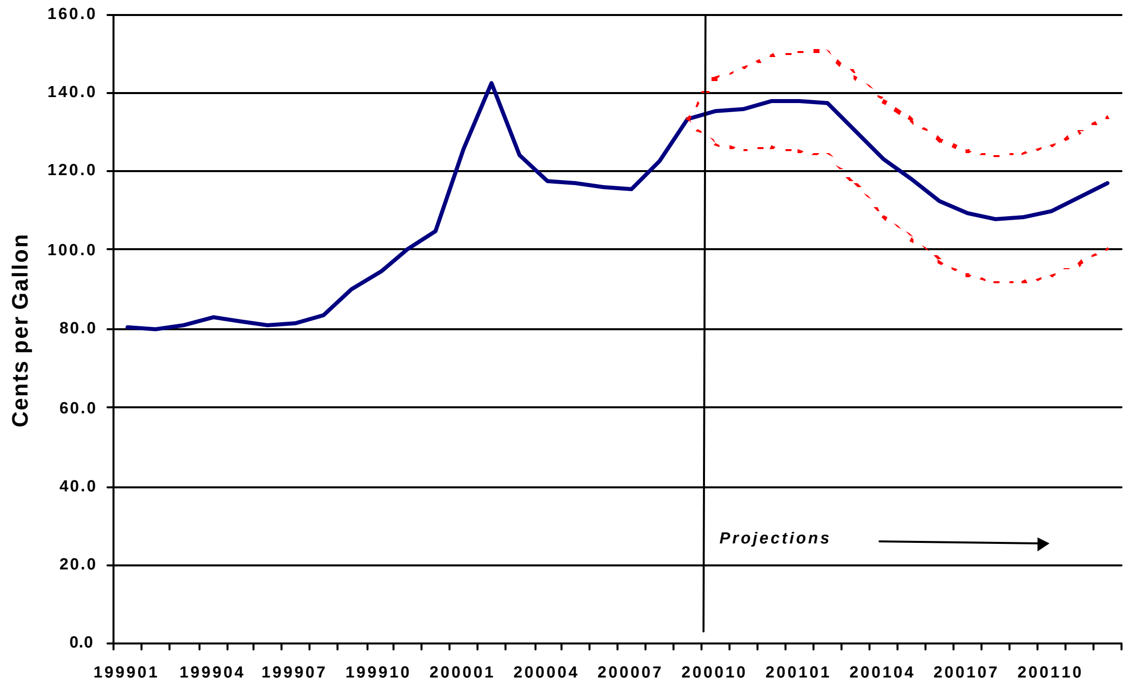
Crude oil costs to U.S. refineries are projected to average 65.2 cents per gallon ($27.62 per barrel), about 10 cents higher than the previous winter's average of 59.3 cents per gallon ($25.11 per barrel). But that projection is less than the peak of more than 80 cents per gallon observed last month. This projection partly reflects the recent decision to release 30 million barrels of crude oil from the Strategic Petroleum Reserve, and the assumption that OPEC increases production in accordance with recent annual quota revisions. Nevertheless, there remains much uncertainty about oil prices this winter, even with normal weather. In the case of very cold weather, we would expect crude oil prices to swing up toward the high end of the uncertainty band depicted in Figure WF5.

Figure WF5. WTI Crude Oil Price: Base Case and 95% Confidence Interval



The combination of substantial rises in crude oil prices, lower inventories, and increased distillate demand is expected to result in higher and more volatile heating oil prices this winter. Residential heating oil prices are projected to average \$1.37 per gallon this winter, compared to an average of \$1.18 last winter (Figure WF6). But only 6 cents of that increase stems from crude oil costs. The remaining increase is related to increased refinery and distribution costs resulting from increased demand under anticipated supply constraints. This contrasts with last winter season's price behavior. The 33 cents-per-gallon rise in crude oil prices at that time accounted for almost all of the increase in wholesale and retail residential heating oil prices--38 cents and 36 cents per gallon, respectively. During that winter, demand, refinery utilization rates and distillate yields were depressed by warmer-than-normal weather, though we did experience a price runup in late January/early February in conjunction with a sharp cold spell.

Figure WF6. Residential Heating Oil Prices: Base Case and 95% Confidence Interval



Propane

Demand

U.S. demand for propane averaged 1.42 million barrels per day during the 1999-2000 winter heating season, more than 5 percent above the previous year's heating season. Strong petrochemical feedstock demand more than offset the impact of a warm winter. Although the U.S. economy remains fairly strong, available data indicate that year-to-date petrochemical feedstock demand has declined by 12 percent, reflecting a price-induced shift towards other petrochemical feedstocks and a slowdown in chemicals industry growth from last year's rapid pace. As a result, average year-to-date propane demand has averaged 1.20 million barrels per day, down more than 2 percent from the same period last year.

Propane demand for the remainder of 2000 is expected to be less than during the same period last year. But crop-drying demand this year could be higher than expected. The U.S. Department of Agriculture (USDA) is forecasting a record corn crop ever at nearly 10.4 billion bushels. If the moisture content of the corn is high, the impact of below-normal inventories in the Midwest could bring about some market volatility during the fourth quarter 2000, especially if the weather turns out to be colder than normal, pending the arrival of propane from other areas of the U.S.

Demand for the upcoming winter season is projected to average 1.42 million barrels per day, about level with that of the previous winter. Increases in space-heating demand brought about by a normal winter are largely offset by the projected declines in petrochemical demand brought about by both seasonal and price factors.

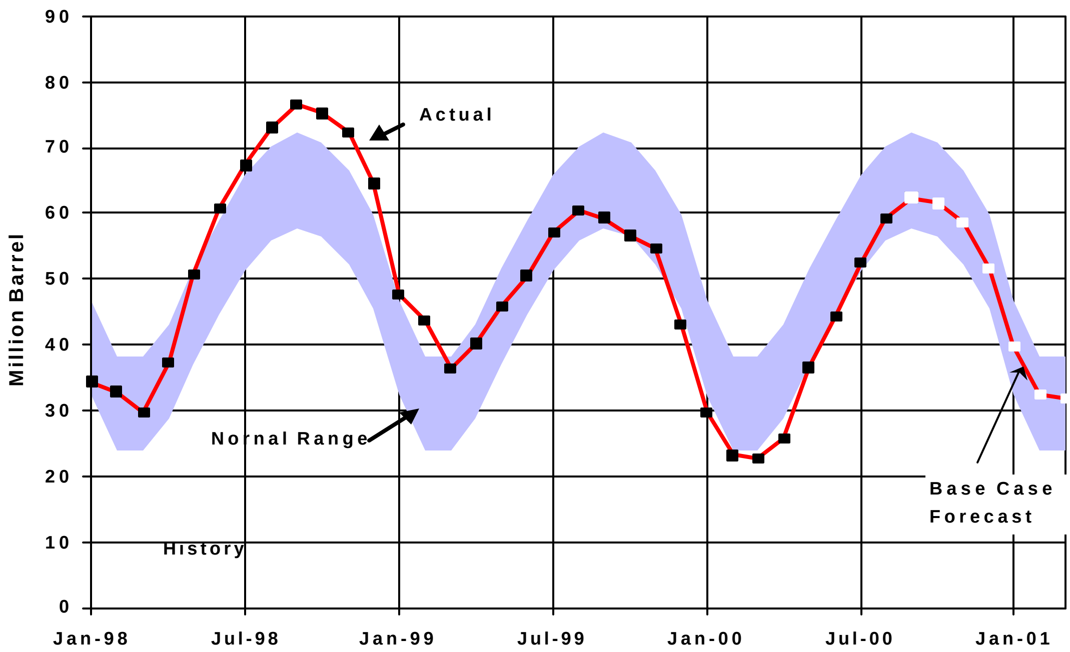
Supply

On the basis of current inventory levels and projected supply and demand, the expectation for the 2000-2001 winter heating season is for adequate propane supplies with higher prices, assuming normal weather and the absence of any major supply disruptions.

Domestic propane production is the most important source of supply, accounting for about 80 percent of requirements during the heating season. For the first half of the year, propane production averaged 1.15 million barrels per day, up nearly 8 percent from the comparable period last year. Refineries, which accounted for most of the annual growth in propane production due to high refinery runs from strong gasoline production, are expected to remain the primary source during the winter season, assuming continued strong growth in the U.S. economy. In addition, high propane prices have provided incentive for gas processors to extract larger quantities of propane compared to last year.

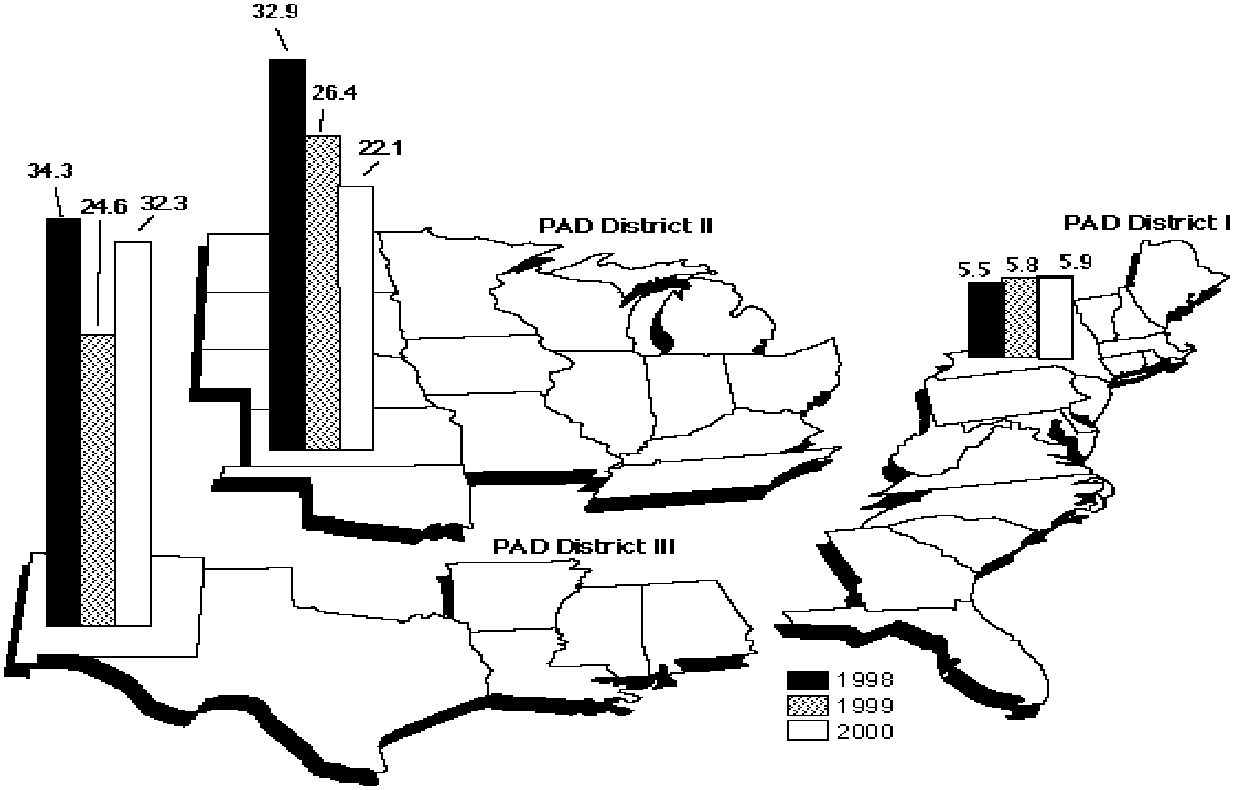
Primary propane inventory withdrawals provide the second largest source of propane during the winter season. Despite last winter's mild weather, U.S. propane inventories fell to 22.7 million barrels by the end of the heating season, 13.7 million barrels below that of the 1998-99 season. This caused concern among industry observers because of the overwhelming need to rebuild inventories to adequate levels by the start of the next heating season. However, last summer's strong stock build pushed inventories to an estimated 62.5 million barrels as of September 30, 2000, slightly above last year's levels. As a result, propane inventories are well within the normal range at the start of the heating season (Figure WF7). Under the base-case scenario, inventories are projected to gradually decline, reaching a level of 32.2 million barrels by the end of March 2001, or 4.2 million barrels higher than last year. Propane is the only major fuel whose end-of-season inventories are projected to he higher than those of the previous season.

Figure WF7. U.S. Propane Stocks



Regional inventories remain mixed (Figure WF8). As of the beginning of the heating season, East Coast and Gulf Coast inventories were at the upper limit of their respective normal ranges, while inventories in the Midwest region continued to track substantially below the normal range. Below-normal inventories in the Midwest region may be cause for some concern due not only to the high concentration of heating demand in the region and but also the potential for larger-than-expected crop-drying demand.

Figure WF8. U.S. Propane Inventories by PAD District (as of September 30)(million barrels)



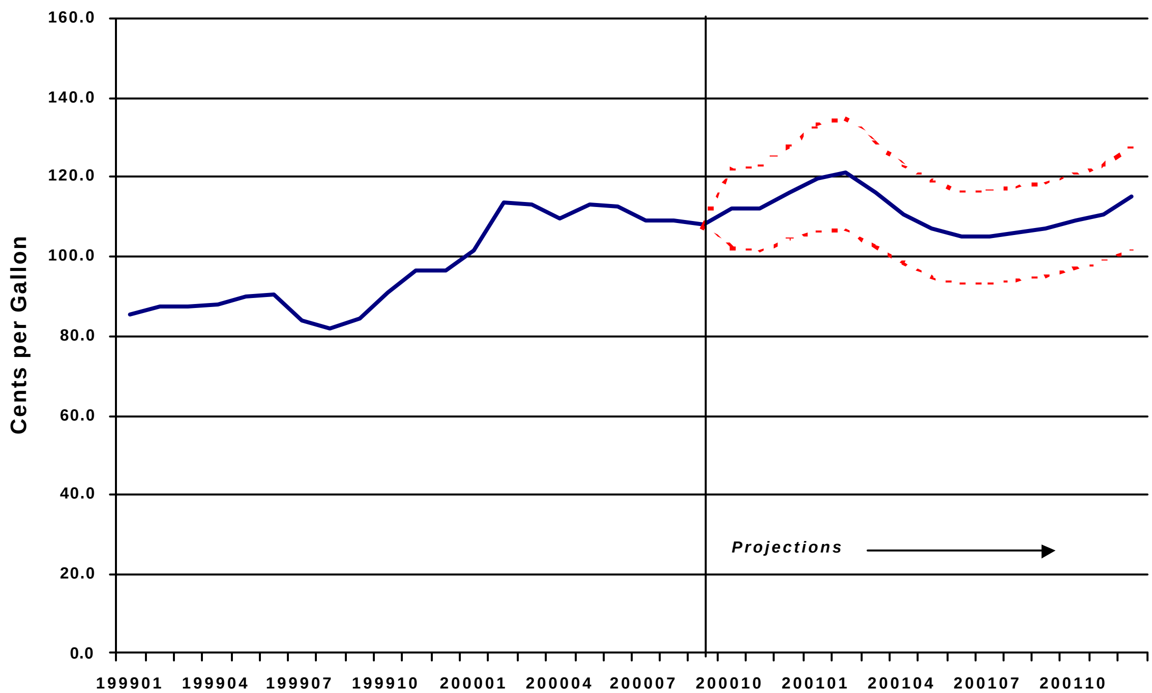
While small in volume, imports provide a crucial source of supply during periods when demand exceeds the available supplies from production and inventories. Propane imports are running slightly above this year compared with last year. Available data for this year indicate that propane imports averaged 125,000 barrels per day, up slightly from 118,000 barrels per day last year. However, the most dramatic shift in imports this year compared with last year was the drop in waterborne imports due to increased world demand for propane coupled with unfavorable economics of importing that product into the U.S. Gulf Coast. However, increases in Canadian imports have more than offset the decline in waterborne imports.

Prices

The primary determinant of spot propane prices, as with most commodities, is the supply/demand balance, which can vary by region. These prices are also influenced by crude oil prices, natural gas prices, the prices of alternative petrochemical feedstocks, and intangible factors such as uncertainty about future supply/demand balances. Despite a strong stock build during the spring and summer months, spot propane prices increased significantly in response to the rise in crude oil prices and anticipated demand. Despite last winter's mild weather, propane inventories continued to track slightly below the normal range for most of the heating season, causing both wholesale and residential propane prices to remain relatively high.

For the upcoming winter season, propane prices are therefore expected to be substantially higher compared with last year. Under the base-case scenario, residential prices are expected to average $1.16 per gallon compared to $1.02 last winter (Figure WF9).

Figure WF9. Residential Propane Prices: Base Case and 95% Confidence Interval



Extreme Weather Cases

In addition to the normal uncertainty surrounding the expected outcomes for key fuel volumes and prices, inferred from the inherent uncertainty of primary determinants (weather and economic growth for examples) as well as the basic stochastic nature of estimating relationships, we have considered demand and price responses under extreme (cold or warm) weather conditions. We have focused on the likely consequences of overall deviations (higher or lower) of 10 percent from normal weather, measured in terms of aggregate heating degree-days.

Based on winter season (October--March) heating degree-days over the period 1975 to 2000, we estimate that the probability of experiencing a winter in which overall degree-days (i.e. total heating degree-days over the winter) are either 10 percent above or below normal ranges of between 5 and 6 percent. But the distribution of the incremental degree-days can be far from even. To simplify the analysis, however, we assume that the 10-percent deviations in either direction are proportionally distributed over the winter based on the "normal" heating degree-day pattern. We did not investigate how this added assumption affects the probabilities associated with the event, but a more typical pattern is admittedly one that is at least somewhat uneven.

Table WF02. U.S. Winter Fuels Outlook: Base Case

	History			Base Case					
	1999-2000			2000-2001			Percent Changed		
	Q4	Q1	Winter	Q4	Q1	Winter	Q4	Q1	Winter
Demand/Supply									
Distillate Fuel (mill. barrels per day)									
Total Demand	**3.75**	**3.75**	**3.75**	3.78	3.97	*3.88*	*0.8%*	*5.9%*	*3.3%*
Refinery Output	**3.50**	**3.27**	**3.39**	3.80	3.51	*3.66*	*8.5%*	*7.3%*	*7.9%*
Net Stock Withdrawal	**0.22**	**0.32**	**0.27**	-0.10	0.35	*0.13*	*-144.3%*	*9.4%*	*-53.0%*
Net Imports	**0.03**	**0.16**	**0.10**	0.10	0.11	*0.11*	*221.5%*	*-29.3%*	*11.3%*
Refinery Utilization (percent)	**91.1%**	**87.3%**	**89.2%**	93.1%	90.5%	*91.8%*			
Natural Gas (bill. cubic feet per day)									
Total Demand	**58.67**	**75.53**	**67.06**	62.34	80.17	*71.16*	*6.3%*	*6.1%*	*6.1%*
Production	**50.79**	**50.53**	**50.66**	51.29	52.39	*51.84*	*1.0%*	*3.7%*	*2.3%*
Net Stock Withdrawal	**4.08**	**14.93**	**9.48**	3.60	14.91	9.19	*-11.7%*	*-0.1%*	*-3.0%*
Net Imports	**9.55**	**9.59**	**9.57**	9.97	10.51	*10.23*	*4.3%*	*9.5%*	*6.9%*
Propane (mill. barrels per day)									
Total Demand	**1.42**	**1.43**	**1.42**	1.38	1.47	*1.42*	*-2.8%*	*2.8%*	*0.0%*
Net Stock Withdrawal	**0.18**	**0.22**	**0.20**	0.12	0.22	0.17	*-34.8%*	*-2.5%*	*-17.1%*
Stocks (ending period)									
Distillate Fuel (MMB) - Beg. [a]	**145**	**125**	**145**	118	127	*118*	*-18.7%*	*1.2%*	*-18.7%*
- End. [a]	**125**	**96**	**96**	127	95	*95*	*1.2%*	*-0.9%*	*-0.9%*
Working Gas (BCF) - Beg. [b]	**2884**	**2509**	**2884**	2530	2199	2530	*-12.3%*	*-12.4%*	*-12.3%*
- End. [b]	**2509**	**1150**	**1150**	2199	857	857	*-12.4%*	*-25.5%*	*-25.5%*
Propane (MMB) - Beg. [a]	**59.4**	**43.0**	**59.4**	62.5	51.8	*62.5*	*5.1%*	*20.4%*	*5.1%*
- End. [a]	**43.0**	**22.7**	**22.7**	51.8	32.2	*32.2*	*20.4%*	*41.8%*	*41.8%*
Prices									
Imported Crude Oil (c/g) [c]	**54.8**	**63.9**	**59.3**	67.3	63.1	*65.2*	*22.8%*	*-1.3%*	*10.0%*
Retail Heating Oil (c/g)	**101.3**	**130.5**	**118.1**	137.8	135.9	*136.7*	*36.0%*	*4.1%*	*15.8%*
Wellhead Gas ($/mcf)	**2.26**	**2.26**	**2.26**	4.57	4.39	*4.48*	*102.6%*	*94.5%*	*98.5%*
Resid. Gas ($/mcf)	**6.85**	**6.48**	**6.61**	8.61	8.54	*8.56*	*25.8%*	*31.7%*	*29.5%*
Resid. Propane (c/g)	**94.7**	**108.7**	**101.7**	113.4	119.0	*116.3*	*19.7%*	*9.5%*	*14.4%*
Market Indicators									
Manuf. Output (index, 1996=1.0)	**1.195**	**1.216**	**1.206**	1.274	1.284	*1.279*	*6.6%*	*5.6%*	*6.1%*
Northeast HDDs per day	**20.6**	**30.7**	**25.6**	22.4	33.0	27.7	*9.1%*	*7.6%*	*8.1%*
Gas-Weighted HDDs per day	**16.5**	**23.2**	**19.9**	18.6	26.2	22.4	*12.6%*	*12.5%*	*12.5%*

[a]mmb = million barrels.
[b]bcf = billion cubic feet.
[c]Refiner acquisition cost (RAC) of imported crude oil.
[d]Percent changes have been adjusted for leap-year effects.
Notes: Minor discrepancies with other EIA published historical data are due to rounding. Historical data are printed in bold; forecasts are in italic. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System. Sources: Historical data: Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109; *Monthly Energy Review*, DOE/EIA-0035. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0900.

Over the last 25 years, only 3 winters even exhibited weather patterns that have led to all months deviating from normal in the *same direction* (1981-1982, 1990-1991, and 1999-2000). All of these winters were warmer than normal, the most significant overall deviation having been recorded last winter (10.7 percent warmer than normal). On the other hand, 2 winters in the last 25 were more than 10 percent colder than normal (1976-1977 and 1977-1978). Interestingly, the coldest winter relative to normal since then was the 1978-1979 winter, when heating degree-days exceeded normal by 8.2 percent. Lest one conclude that we have inadvertently overstated the probabilities here in view of the apparent concentration of colder periods in the early part of the sample period, we have made adjustments for warming trends that have been identified in mean temperatures by season in the United States. The difference in mean winter degree-day deviations from normal between the first half of the sample period and the second half of the sample period is not statistically significant.

This winter, with low heating oil stocks and relatively low natural gas in storage at the beginning of the season, we see an enhanced risk of significant upward price shocks under a scenario in which heating degree-days are 10 percent colder than normal. For propane, which starts the season with inventory levels near normal nationally (albeit still somewhat below normal in the Midwest region) the upward price risk is present but not as significant as the other heating fuels. We characterize the potential price variance for heating fuels under extreme weather conditions as asymmetrical between upward and downward risk, with a significantly higher absolute price response likely under extreme cold weather than under extremely warm conditions. The key results, which are expressed in percent changes, are summarized below:

Table WF03. Severe Weather Scenarios: Percent Deviations from Base Case

	10% Colder	10% Warmer
Natural Gas		
Demand	2.6%	-3.8%
Residential Price	10.5%	-4.6%
Distillate Fuel Oil		
Demand	1.8%	-2.6%
Residential Price	30.0%	-15.4%
Propane		
Demand	2.6%	-2.8%
Residential Price	5.5%	-3.5%

Because propane supply appears to be adequate to satisfy demand without any obvious difficulty under most circumstances likely to arise this winter, we do not expect particularly large swings in propane prices relative to the base case this winter if weather is substantially colder or warmer than normal.

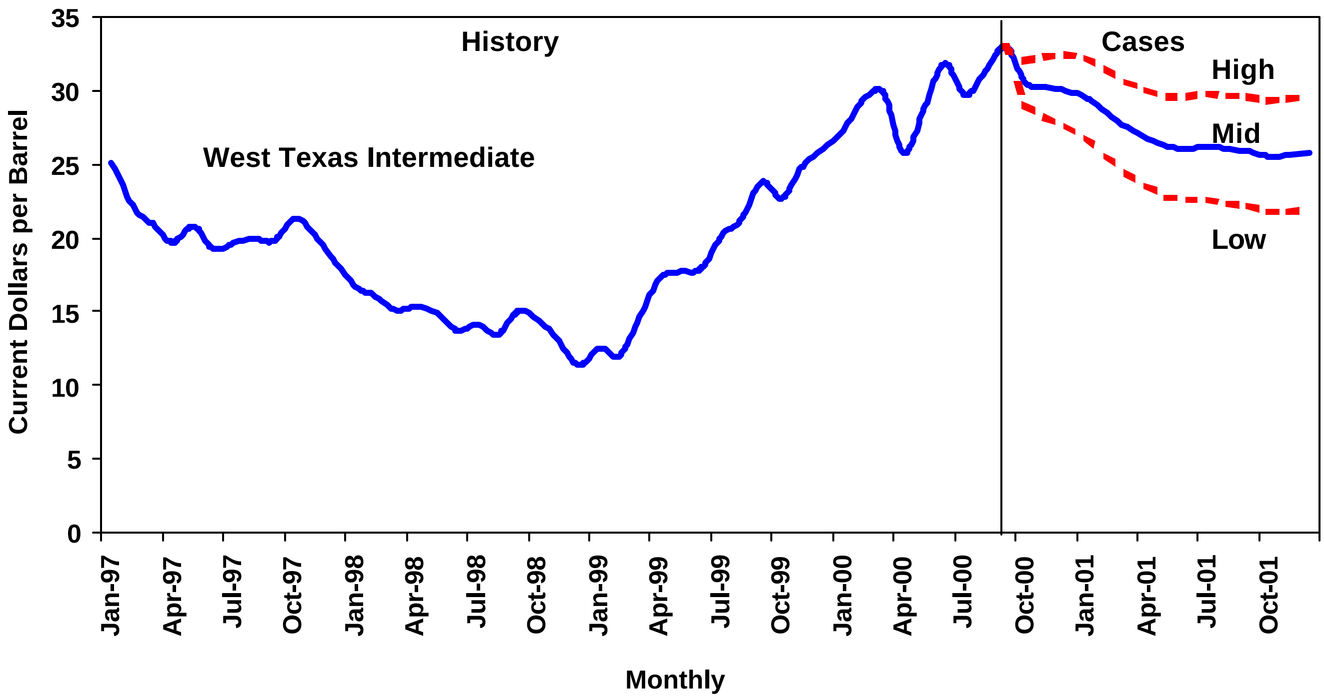
For natural gas and heating oil (or distillate fuel generally), a winter scenario this year which includes the assumption that weather is 10% colder than normal is likely to generate particularly strong upward price movements. Starting from relatively tight supply conditions in these markets, the ultimate volumetric supply response to such a demand shock would be expected to be small and the change in the market clearing price relatively large. We estimate that the potential ranges of price increases would extend to 30 percent higher residential heating oil prices and 10 percent higher residential gas prices above the base case under the colder-than-normal scenario. For the winter period itself, these constitute the outside ranges of cold weather-induced price shocks in our view.

In a 10 percent warmer-than-normal scenario, more of a volume response is possible on the supply side (i.e. refinery runs can be cut, spot purchases reduced) and market clearing can occur with smaller absolute price changes. In the warm weather case, we would expect key heating fuel prices to residential consumers to range 4 percent to 15 percent below base case levels, with the strongest relative price reaction to be evident in the Northeast heating oil market.

The Outlook

Outlook Assumptions

Figure 1. U.S. Monthly Crude Oil Prices

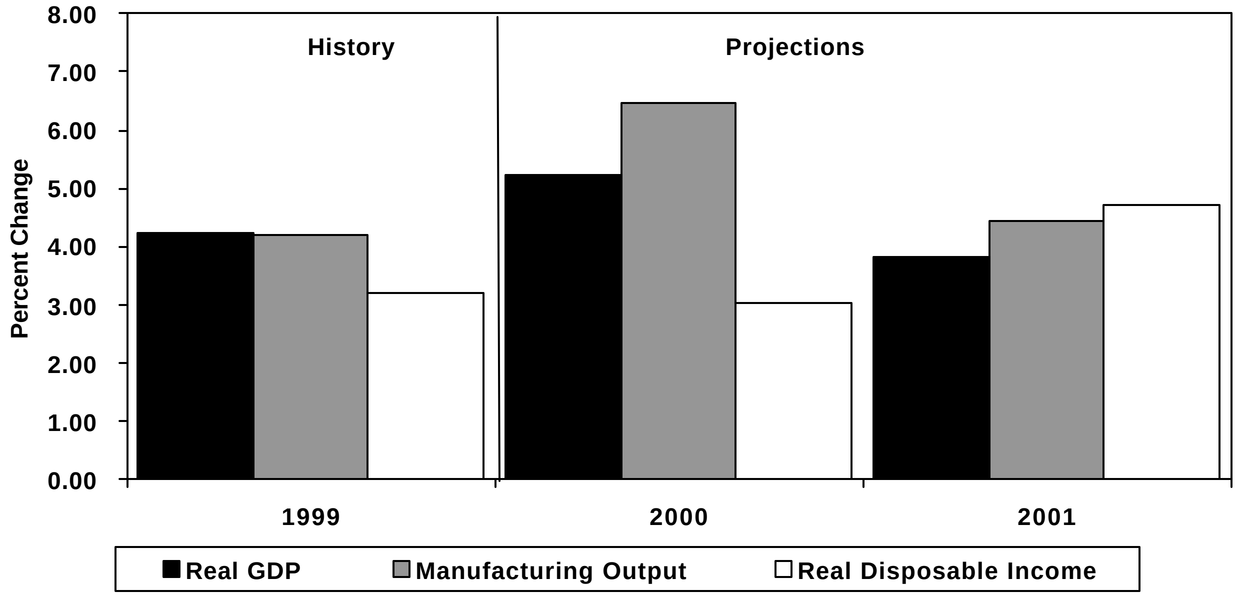


World Oil Prices

The monthly average oil price for West Texas Intermediate (WTI) crude oil rose in September to an estimated $33.88 per barrel. This marks the highest monthly average nominal oil price level in the decade since the Gulf War (Figure 1). During September, the WTI crude oil price rose sharply to above $37 per barrel as near term supply indicators, including U.S. crude oil stock data, continued to indicate tight supplies. On September 22, U.S. Energy Secretary Bill Richardson announced the decision by President Clinton to release 30 million barrels of crude oil from the Strategic Petroleum Reserve with the objective of helping to alleviate the low U.S. crude inventory situation and to encourage incremental production of heating oil for use in the undersupplied Northeast market. We estimate that, in reaction to the announcement, spot WTI prices fell by about $3 per barrel, serving to flatten somewhat a sharply backwardated forward crude price curve.

EIA estimates of world oil supply and demand suggest that the monthly price will remain above $28 per barrel for the remainder of the year. Prices are then expected to gradually decline in 2001 and average near $25 per barrel, about $3.00 below the annual average for 2000. This 2001 price projection is roughly the same as in the September Outlook projection.

Figure 2. U.S. Macroeconomic Indicators
(Percent Change from Year Ago)



Economic Outlook

In 2000 and in 2001, GDP is expected to continue to grow at the rates of 5.2 percent and 3.8 percent respectively, compared with 4.2 percent growth in 1999. Personal disposable income is assumed to be up by about 3.0 percent in 2000 and by 4.7 percent in 2001, compared with the 1999 rate of growth of 3.2 percent (Figure 2 and Table 1).

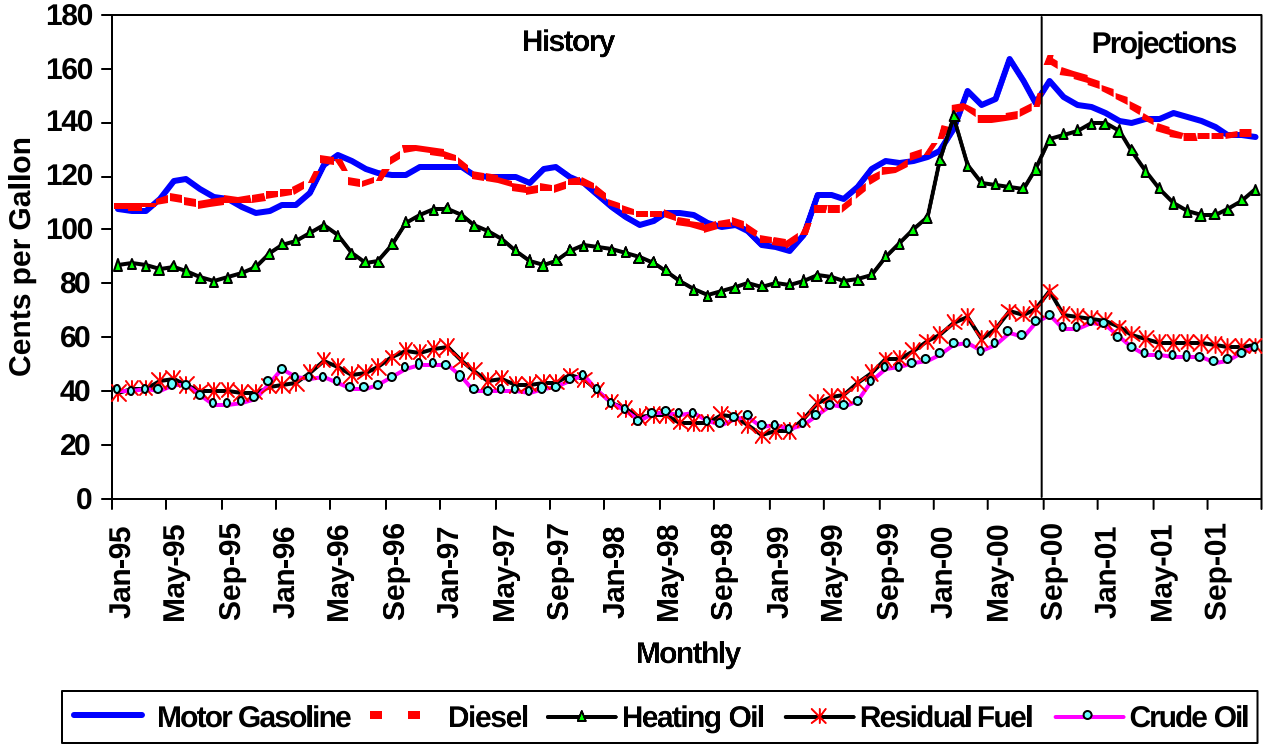
Inflation (consumer price index: see Table 2) is expected to show some acceleration this year. Consumer price inflation is expected to be 3.3 percent in 2000, up from the 2.2 percent seen in 1999. However, consumer price increases are expected to ease somewhat to about 2.0 percent in 2001. Manufacturing production is expected to grow by 6.5 percent in 2000 compared with 4.2 percent growth in 1999 (Table 1). In 2001, manufacturing production is assumed to increase by an additional 4.2 percent.

Weather Assumptions

Weather patterns (expressed as heating and cooling degree-days in Table 1) are assumed to be normal during the remainder of 2000 and in 2001 in our base case projections. This would imply that, for this winter, heating degree-days would be about 12 percent above last winter.

U. S. Energy Prices

Figure 3. Petroleum Product Prices



Average crude oil prices for this winter are likely to be about $2.50 per barrel higher than the crude price during the same period a year ago. These higher crude oil prices mean higher petroleum product prices, with winter year-to-year gains averaging 10-20 cents per gallon (Figure 3 and Table 4). In 2001, though, crude oil prices are projected to fall, meaning lower petroleum product prices.

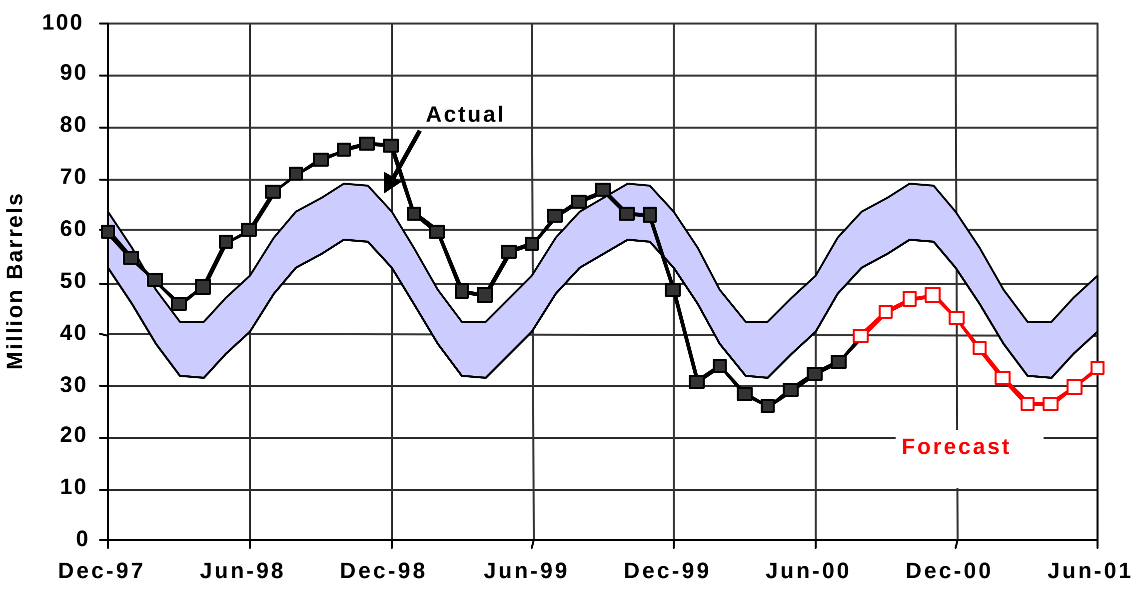
Distillate Fuel (Heating Oil and Diesel Fuel): Spot prices for distillate fuel oil climbed steadily from late July through the middle of September, gaining about 30 cents per gallon over that period. Recently, spot prices slid back by about 8-10 cents per gallon with the anticipation and then the announcement of the limited exchange of oil from the Strategic Petroleum Reserve (SPR), scheduled for late October and November. Currently, however, distillate stocks, particularly those in the Northeast, where 75 percent of the nation's heating oil is consumed, remain at very depressed levels (Figure 3). These low stocks levels increase the potential for high price volatility for distillate spot prices this fall and winter. In late January and early February of last year, very cold weather in the Northeast in combination with notably low stocks of distillate fuel, sent spot prices soaring by nearly $1.00 per gallon in a period of less than 3 days. Heating oil and diesel fuel prices averaged more than $2.00 per gallon for a time in New England and other areas in the Northeast.

As we have been stating in the last several *Outlooks*, a risk exists for price spikes of distillate fuels similar to last February unless inventories of distillate fuels are built to sufficient levels by the end of the year. The additional petroleum supply from the SPR is expected to marginally improve this situation somewhat.

For the U.S., distillate stocks are currently about 25 million barrels or 21 percent below the middle of the distillate stock range.

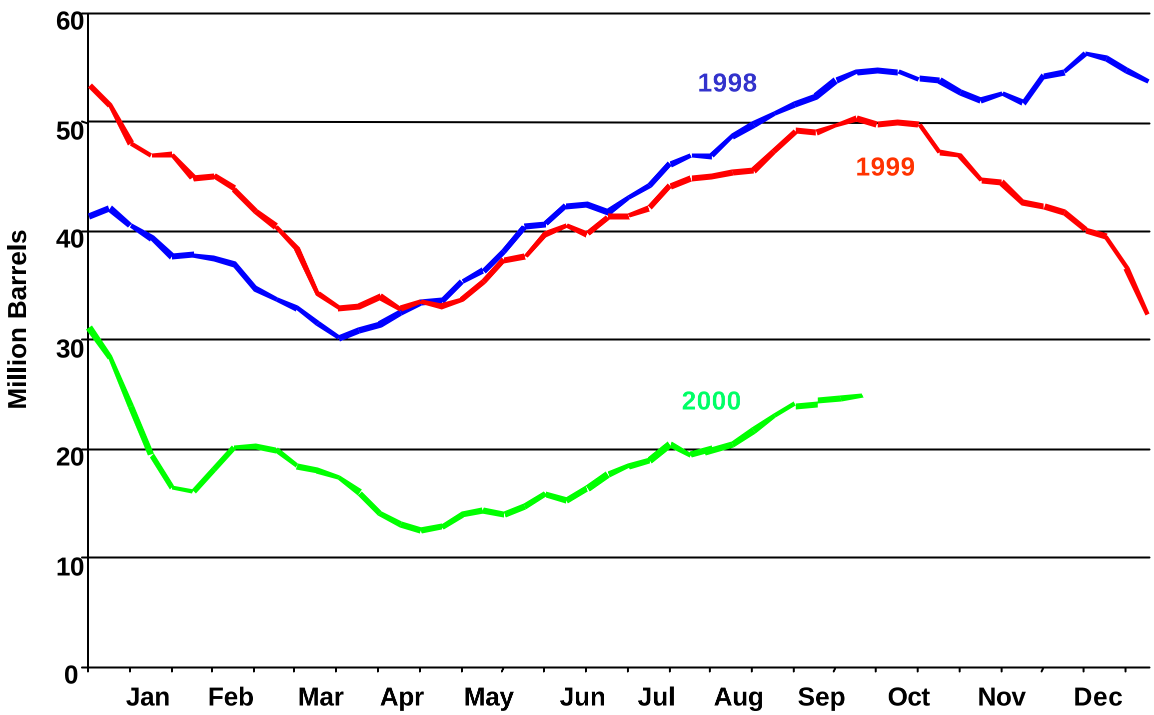
East Coast distillate stocks are about 25 percent below the average range (Figure 4). East Coast heating oil stocks are approximately half of what they were one year ago. (Figure 5). While it is true that EIA's definition of the average range for petroleum product stocks is based on only 3 years of monthly data (January 1997- December 1999) and that the end-of-September distillate stock levels for those years were relatively high by longer historical standards, it remains true that, by historical standards, the day's supply of distillate fuel is currently quite low and will be closely monitored over the next few months.

Figure 4. East Coast Distillate Stocks



NOTE: Colored Band is Normal Stock Range

Figure 5. Weekly East Coast Heating Oil Stocks



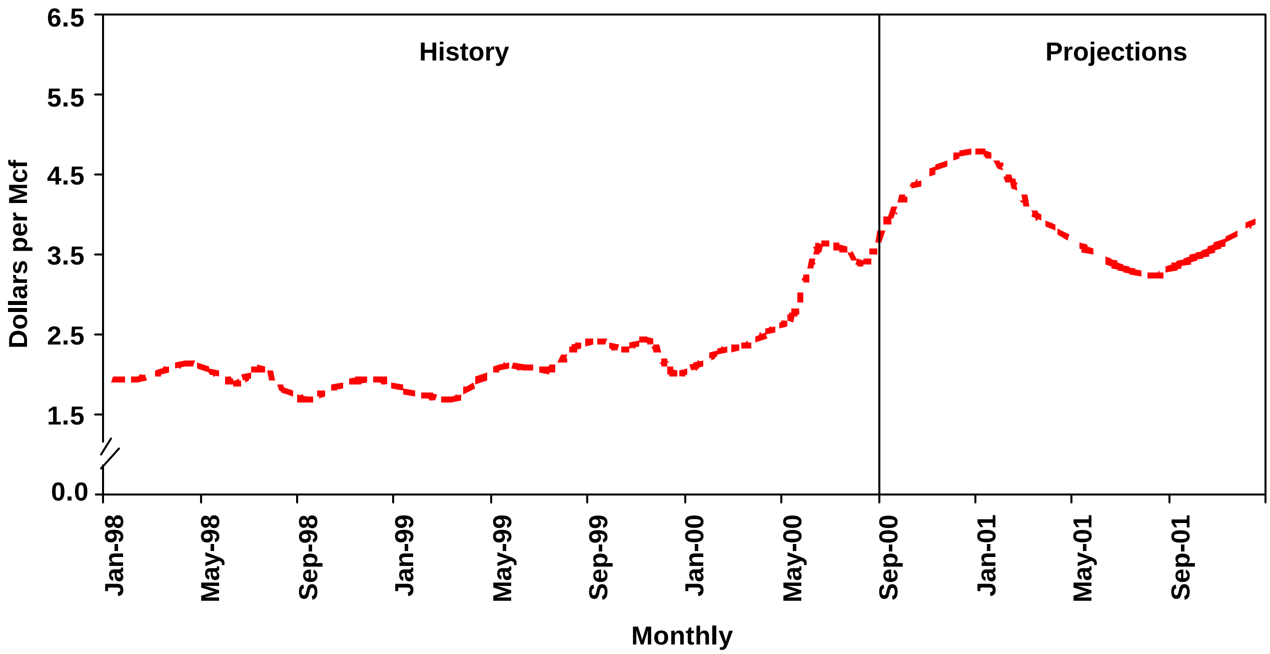
We are projecting that distillate inventories will increase through November and by the middle of the winter, but the levels will be tight even though the additional supply from the SPR oil exchange should raise these levels somewhat (about 3-5 million barrels). Still, there will not be much of buffer in these projected stock levels, especially if the winter in the Northeast is unusually cold. Unless the winter in the Northeast is unusually mild and/or world crude oil prices collapse, we believe that substantial year-on-year price increases for heating oil and diesel fuel on the East Coast are unavoidable.

Assuming normal heating demand with tight stocks and somewhat higher crude oil prices, we expect that in the winter, residential heating oil price are projected to average $1.37 per gallon or about 19 cents more per gallon compared to the same period last year (Table 4). Diesel prices, which are tied to heating oil prices in the winter (particularly in the Northeast), are projected to experience similar year-on-year gains.

Motor Gasoline. Motor gasoline prices have traveled a rocky road this past driving season. Pump prices rose by more than 20 cents per gallon from January to March, then, counter-cyclically, backed down a bit in April and May. In June regional supply problems and high crude oil prices sent the average retail price soaring. Regular unleaded, self-service retail motor gasoline prices hit their highest monthly level ever, ***in nominal terms,*** averaging $1.63 per gallon in June**.** Still, in ***real terms*** (adjusted for inflation) that price was about 40 percent lower than the price experienced in March 1981. Prices at the pump eased once more in July and August, but began climbing again in September in response to higher crude oil prices. Recently both crude oil prices and spot prices for motor gasoline have been easing, as have pump prices for gasoline. We expect the regular unleaded retail gasoline price to average about $1.46 in December, about 19 cents more than the December 1999 price, and about $1.45 per gallon next summer, about 11 cents less than this past summer's price.

Natural Gas. Since June, spot wellhead prices have consistently been averaging over $4.00 per thousand cubic feet (mcf). In fact, during the entire last half of September, spot prices for gas have hovered over the $5.00 per mcf. Although the spot price for natural gas has exceeded these levels in the past for short periods of time, they have not remained at these levels over such a sustained period of time. Current wellhead prices are nearly double the price from one year ago (Figure 6). Although rising crude oil prices have encouraged natural gas prices to grow, the principal explanation for these high (and sustained) gas prices has been the strained supply situation. In sum, the injection rate for gas into storage continues to be too small to assure the market of sufficient supplies for next winter's heating season. Underground working gas storage levels are currently about 12 percent below year-ago levels, which is about 9 percent below the 1995-1999 average. It should be noted that, with summer over, gas injection rates have been picking up and are likely to improve relative to normal rates. However, unless injections pick up sharply, the availability of natural gas for next winter may be constrained for some classes of customers, particularly if the winter is very cold. This assessment is reflected in the high spot and near futures prices that have been evident over the last four months. Hot summer weather in portions of the country, particularly Texas and California, which consume large amounts of gas for electricity generation, drew gas away from storage injections. Natural gas that would normally be added to storage has, to some extent, been used (indirectly through electric utilities) to run air conditioners.

Figure 6. Natural Gas Wellhead Price



Overall, demand for natural gas has been gaining due to the growing economy over the last eight years and due to the increasing use of gas generation at power facilities. While natural gas imports have generally been rising significantly in recent years, the United States may be running into some short-term supply constraints. Several years of relatively low prices have slowed down exploration and drilling for new sources of supply. Recent higher prices have caused exploration and drilling to rebound, but additional supplies are not likely to expand production in any significant way before the heating season ends.

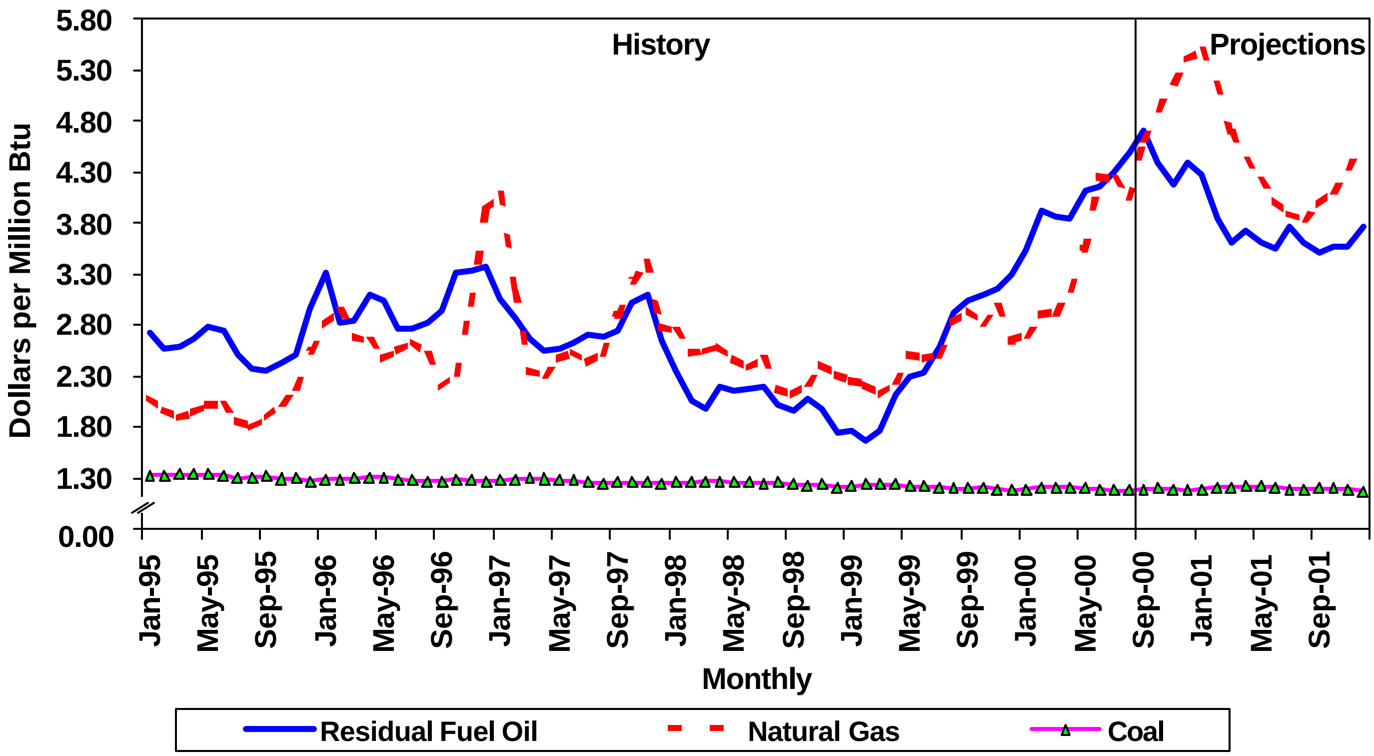
Natural gas prices at the wellhead are projected to almost double this winter (October-March) compared to last winter. Naturally, higher end-use prices will result from higher projected wellhead prices. If our base case projections hold, residential customers will be paying prices for natural gas that are nearly 30 percent higher than last winter.

This year the average wellhead price for natural gas is projected to average almost $3.40 per thousand cubic feet (Table 4). In nominal terms, this projected price would be the highest annual wellhead price on record; in real (inflation-adjusted) terms this projected price represents the highest annual average price since 1985.

Our base case projections assume normal weather for the remainder of the forecast period. On the other hand, there is a downside risk to any high priced commodity. Mild weather occurring over lengthy periods of time in the gas consuming regions of the Nation could scuttle these projected price increases. Next year, we are projecting higher prices in the first half of the year compared to the previous year, but lower prices for the second half of the year.

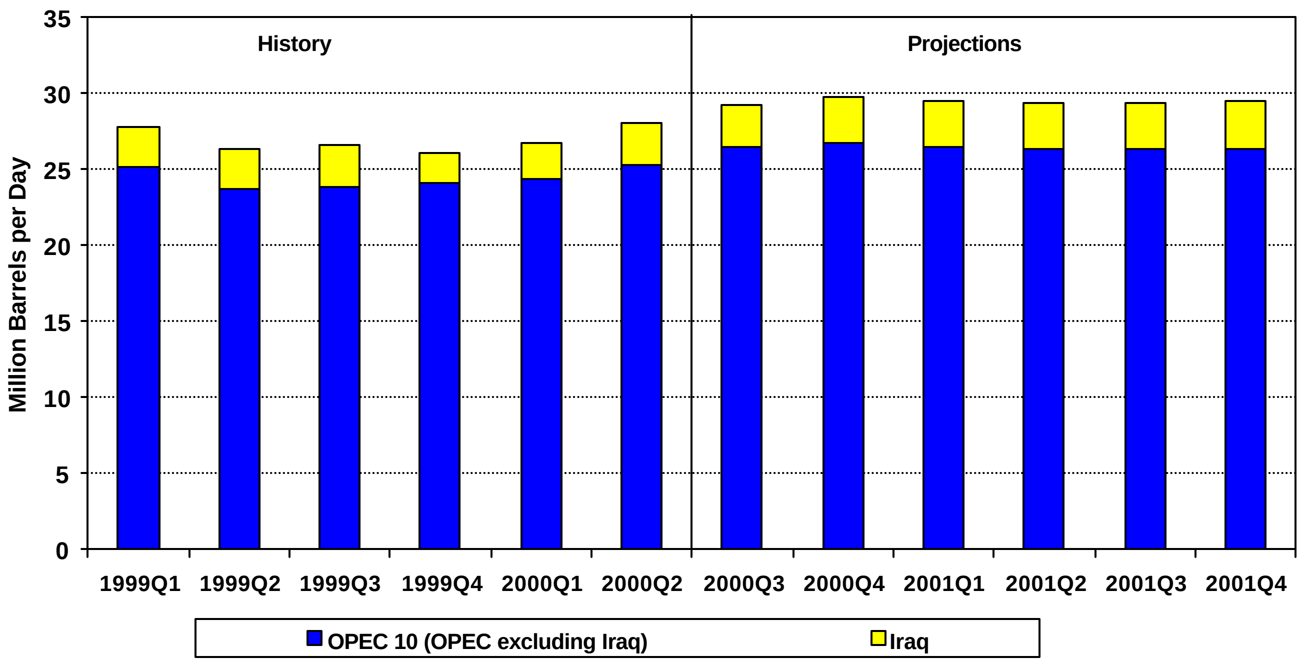
Electric Utility Fuels. Natural gas for power generation is estimated to have yielded its apparent average price advantage over residual fuel oil by the end of the summer. The heavy oil is also projected to be the cheaper of the two fuels throughout the year 2001 (Figure 7).

Figure 7. Fossil Fuel Prices to Electric Utilities



International Oil Supply

Figure 8. OPEC Crude Oil Production 1999-2001



Saudi Arabia announced on July 3 that it wanted to bring the OPEC basket price down to $25 per barrel, and that crude oil supplies would be increased by an additional 500,000 bbl/d above the July 1 quotas if crude oil prices remained high. Although this announcement caused some contention within OPEC, the OPEC 10 (Organization of Petroleum Exporting Countries excluding Iraq) countries agreed that additional oil production was needed to moderate world oil prices, and on September 10, OPEC 10 member countries agreed to increase their production quotas by an additional 800,000 barrels per day effective October 1.

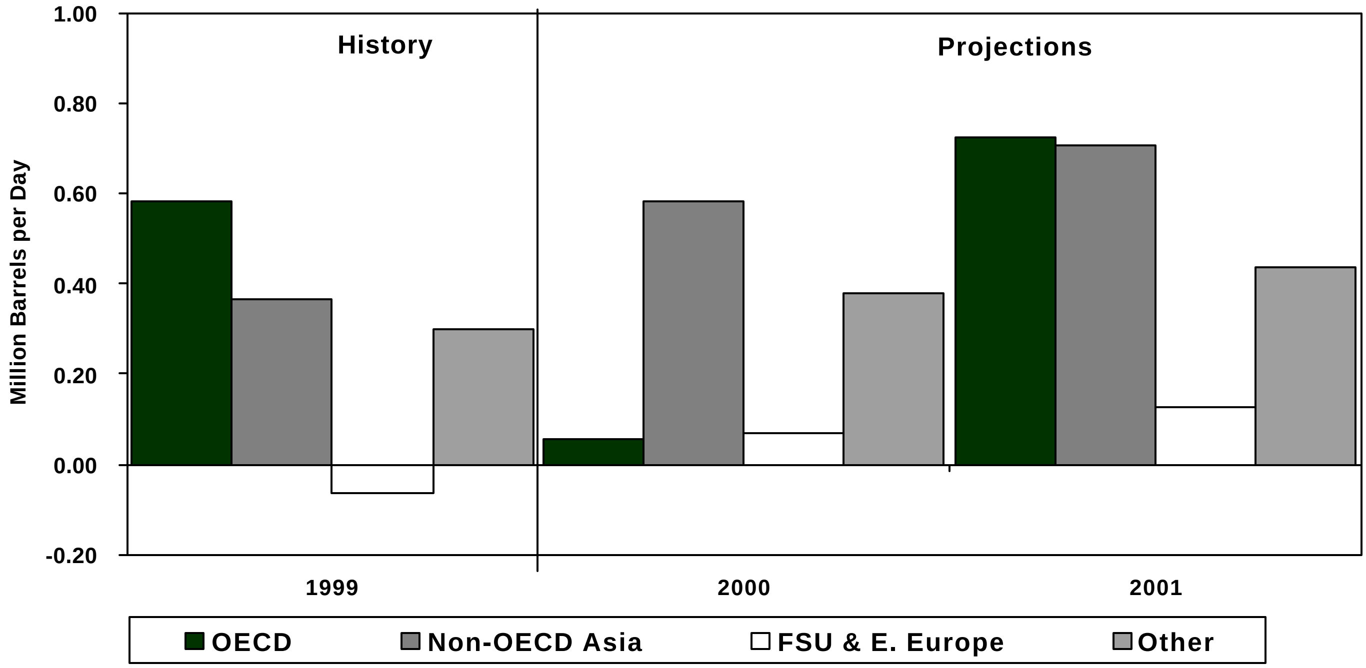
Saudi Arabia apparently did not wait until October to increase its oil production. EIA estimates that the OPEC 10 countries produced about a million barrels per day above their third quarter quotas, with most of the excess coming from Saudi Arabia. After the latest round of quota adjustments, only Saudi Arabia and the United Arab Emirates are believed to have significant capacity to expand production during the fourth quarter. The forecast assumes that OPEC 10 production in the fourth quarter of 2000 will be 0.3 million barrels per day higher than in the previous quarter, with the increase coming primarily from Saudi Arabia. EIA's projection does not assume further increases in OPEC 10 production in 2001, and assumes that Saudi Arabian production will decline from its projected fourth quarter level of 9.3 million barrels per day during the first half of 2001 (Figure 8).

Iraqi crude oil production is estimated to have increased from 2.3 million barrels per day in the first quarter to 2.8 million barrels per day in the third quarter of 2000. Although Iraqi production fell during June-July as a result of logistical and marketing problems, Iraqi oil production is projected to increase to 3.0 million barrels per day through the remainder of the year, and increase to 3.2 million barrels per day by end-2001. These EIA projections of Iraqi crude oil production are assumptions that do not reflect any official U.S. Government view, and are less than Iraq's own estimate that production could reach as high as 3.5 million barrels per day in 2001.

Non-OPEC production is expected to increase by 1.2 million barrels per day in 2000 and by another 0.7 million barrels per day in 2001, particularly from the former Soviet Union, with smaller increases from other regions (Table 3). Oil production from the former Soviet Union has risen as Russian production has recovered, and further increases are expected at end-2001 with the opening of the Caspian Pipeline Consortium (CPC) pipeline to transport oil from Kazakhstan to world oil markets. No further increases are expected in the North Sea in 2001 as declines in maturing fields outstrip begin to outstrip production from new fields coming online, particularly in the U.K. sector of the North Sea.

International Oil Demand

Figure 9. Annual World Oil Demand
(Changes from Previous Year)

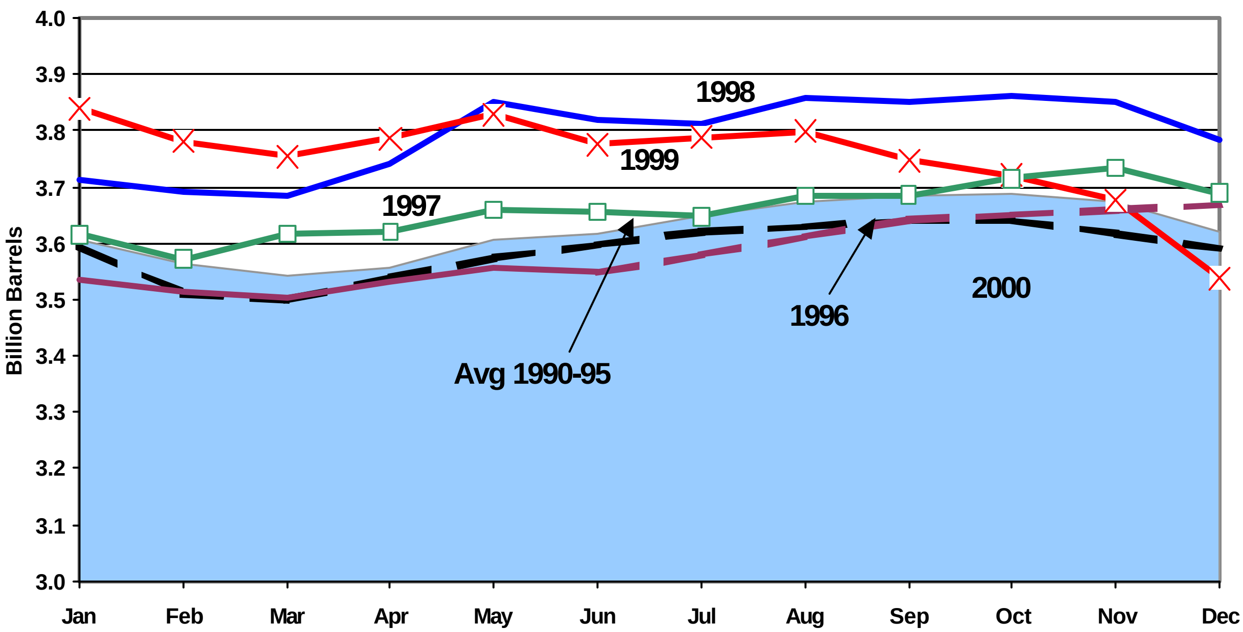


This month's Outlook assumes growth in world oil demand in 2000 of a little more than 1 million barrels per day (about 1.5 percent), to average almost 76 million barrels per day for the year (Figure 9). This is the lowest growth rate since 1993 with the exception of 1998, when Asian economies were suffering from a financial crisis. World oil demand in 2001 is expected to grow about 2 million barrels per day, similar to the growth that was seen in the 1995-1997 period.

Non-OECD Asia is expected once again to be the predominant region for oil demand growth this year, although near-term growth rates there are unlikely to match those seen in the early to mid 1990s. By 2001, not only is non-OECD oil demand expected to grow even more, but OECD oil demand growth is expected to be strong as well, with half of the demand growth coming from the United States.

World Oil Stocks, Capacity and Net Trade

Figure 10. Total OECD Oil Stocks*

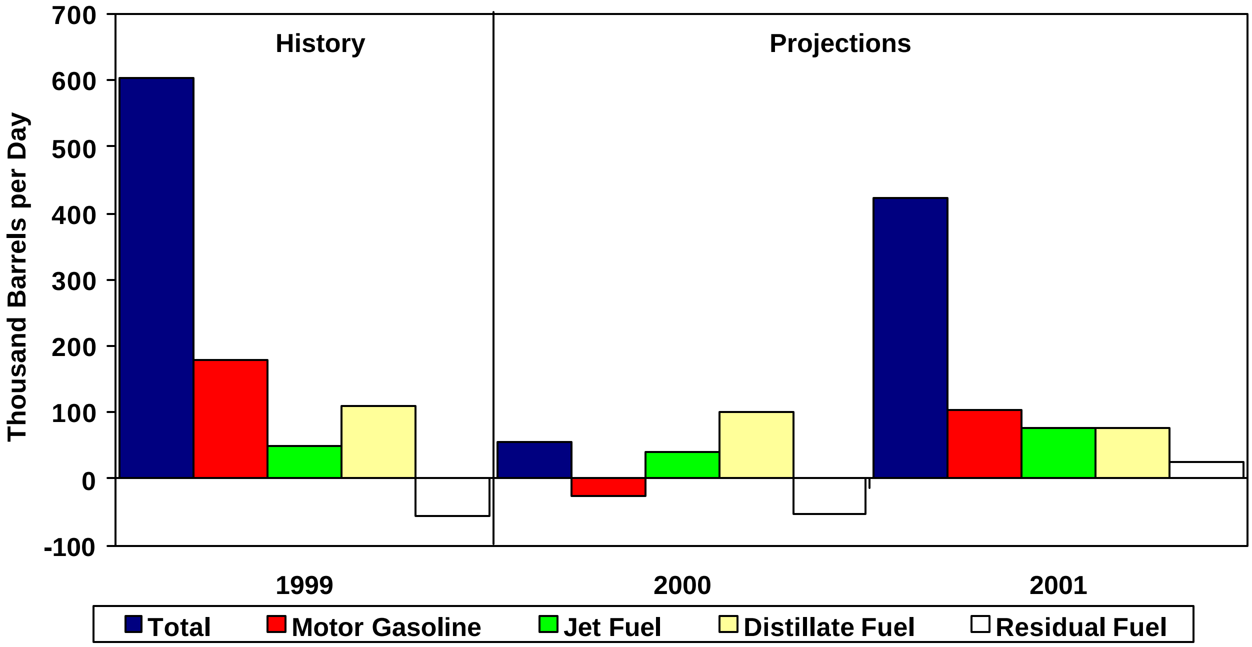


*Total includes commercial and government stocks

While EIA does not attempt to estimate oil inventory levels on a global basis, the direction oil inventories are headed is discerned from EIA's world oil supply and demand estimates. Following a 0.8-million-barrel-per-day draw on world inventories in 1999, stocks reached very low levels when viewed on a forward-cover or days-supply basis. The increased production levels seen from OPEC in the third quarter and further OPEC production increases expected in the fourth quarter imply a projected oil inventory build of about 1 million barrels per day in 2000. OECD stock levels, which EIA does estimate, are projected to rise from their very low levels by end-2000 to be about 2 days' supply higher than year-earlier levels, leaving world oil markets less vulnerable to a disruption in oil supplies or an extreme cold snap during next winter (Figure 10). The increased levels of OPEC production are also expected to result in further stock builds in 2001. However, OECD inventories are projected to increase at a lower rate in 2001 because of rapidly rising world oil demand, and projected to grow by one additional days' supply in 2001.

U.S. Oil Demand

Figure 11. Petroleum Products Demand (Year-to-Year Change)



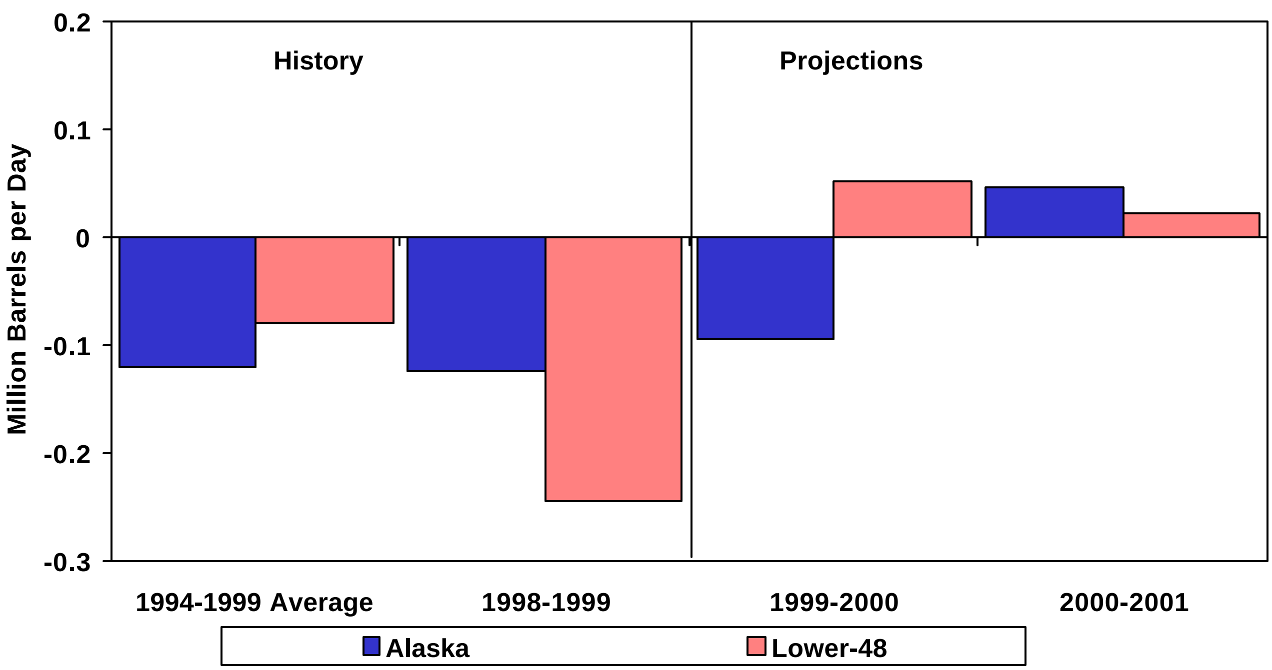
Petroleum demand is expected to increase by an average of 60,000 barrels per day, or 0.3 percent, during the year 2000, and by more than 420,000 barrels per day, or 2.2 percent, in 2001. Despite that recovery, average annual growth for the two-year period is still substantially less than the 430,000 barrels-per day, or 2.3 percent, growth rate of the preceding two years. Contributing to the moderation in oil demand growth (Figure 11) for the forecast interval are: higher energy prices, which, despite gradual declines from their recent peaks, are projected to end the forecast period substantially higher than at the beginning of 2000; milder-than-normal weather during the first quarter of this year; and moderation in economic growth in 2001. Higher oil prices, in fact, are expected to reduce residual fuel oil demand for much of the forecast interval, reversing increases in demand for residual oil in the previous 2 years, during which oil prices had fallen to record lows.

Both higher fuel prices and mild weather have contributed to the relatively weak demand growth in 2000. Despite the absence of growth projected for motor gasoline demand, total transportation-related demand (which includes jet fuel and diesel) is projected to increase almost 2 percent. Aside from a cold snap in late January and the consequent heating oil price run-up in the Northeast, last winter's weather was warmer than normal for the first quarter, constraining space-heating demand growth for petroleum products for the year as a whole to less than 1 percent. Following a 6-percent decline in 1999, residual fuel oil demand is projected to decline a further 6 percent as a result of price-related fuel switching in the electric utility and industrial sectors. Much of that decline, however, is believed to have taken place during the first half of the year; power generators can expect to increase their second-half purchases of fuel oil to increase to levels slightly higher than during the same period in 1999 as a result of declines in residual oil prices and increases in natural gas prices.

In 2001, a presumed return to normal weather and a continued retreat of oil prices from their peaks of the previous year are projected to contribute to the boost in total petroleum demand by 420,000 barrels per day, or 2.2 percent. Transportation demand is projected to rise by 1.5 percent, reflecting a slight increase in motor gasoline demand from its price-restrained growth in 2000 and slower growth in diesel demand. Residual fuel oil shipments are expected to recover from the lows of the previous year, reflecting strength in electric power purchases.

U.S. Oil Supply

Figure 12. U.S. Crude Oil Production (Year-to-Year Change)



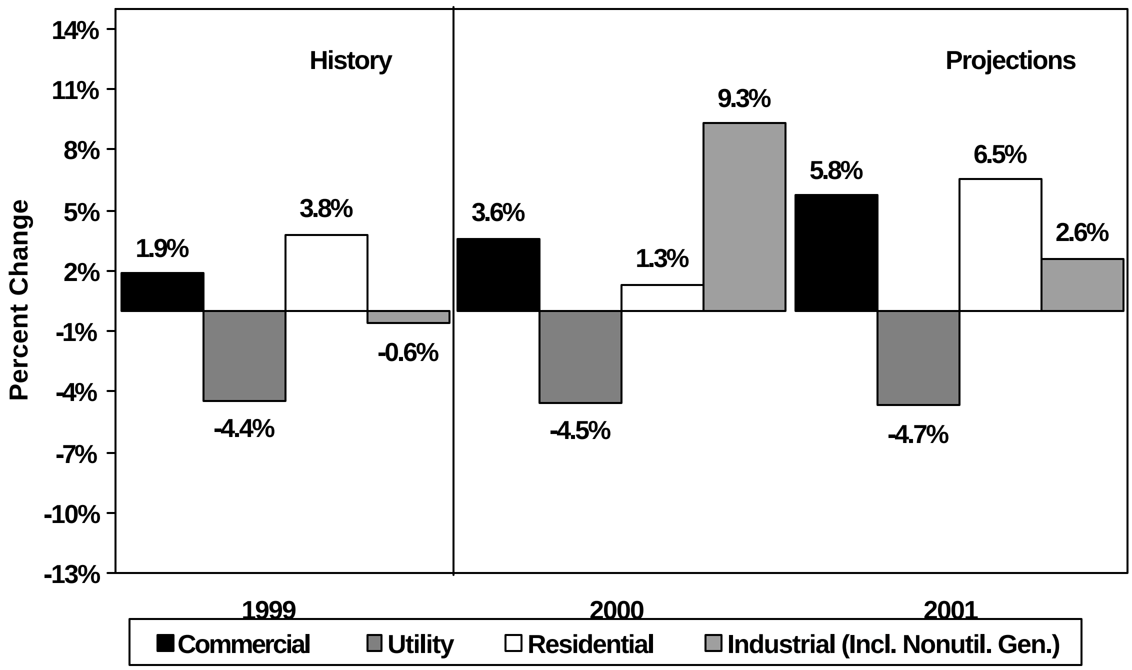
Even though crude oil prices rebounded dramatically in 1999, U.S. crude oil production did not. Domestic crude oil production declined throughout 1999, with the average for the year falling by 370,000 barrels per day, or 5.9 percent, from the 1998 average. However, a much smaller decline of 40,000 barrels per day (0.7 percent) is expected in 2000, followed by a small recovery of about 70,000 barrels per day in 2001 (Figure 12).

Lower-48 States oil production is expected to increase by 52,000 barrels per day in 2000, followed by an increase of about 22,000 barrels per day in 2001. Oil production from the Auger, Mars, Troika, Ursa, and Diana-Hoover Federal Offshore fields is expected to account for about 9.1 percent of the lower-48 oil production by the 4th quarter of 2001. Shell started production in 1999 in their Ursa field, which will peak in the year 2000 at 147,000 barrels per day of condensate. Exxon's Diana and Hoover started production in mid 2000 at a rate of 30,000 barrels per day, expected to increase to 100,000 barrels per day in early 2001.

Alaska is expected to account for 16.9 percent of the total U.S. oil production in 2001. Alaskan oil production is expected to decline by 8.6 percent in 2000 and increase by 4.1 percent in 2001. A substantial portion of the oil production from Alaska comes from the giant Prudhoe Bay Field. Other then the routine maintenance, no major investments are planned for this field during the forecast period. Therefore, the field is expected to follow a steeper decline during this period than has been observed in other time periods. Oil production from recent discoveries such as Sambuca and Midnight Sun are marginal and are not expected to substantially offset the decline in oil production from the Prudhoe Bay and other fields in the North Slope in 2000. Production from the Kuparuk River field plus like production from West Sak, Tabasco and Tarn fields is expected to stay at an average of 236,000 barrels per day in 2000-2001 forecast period. The Alpine field is expected to come on in last quarter of 2000 at an initial rate of 40,000 barrels per day peaking at 80,000 barrels per day in mid 2001.

U.S. Natural Gas Demand

Figure 13. Annual Changes in Natural Gas Demand by Sector

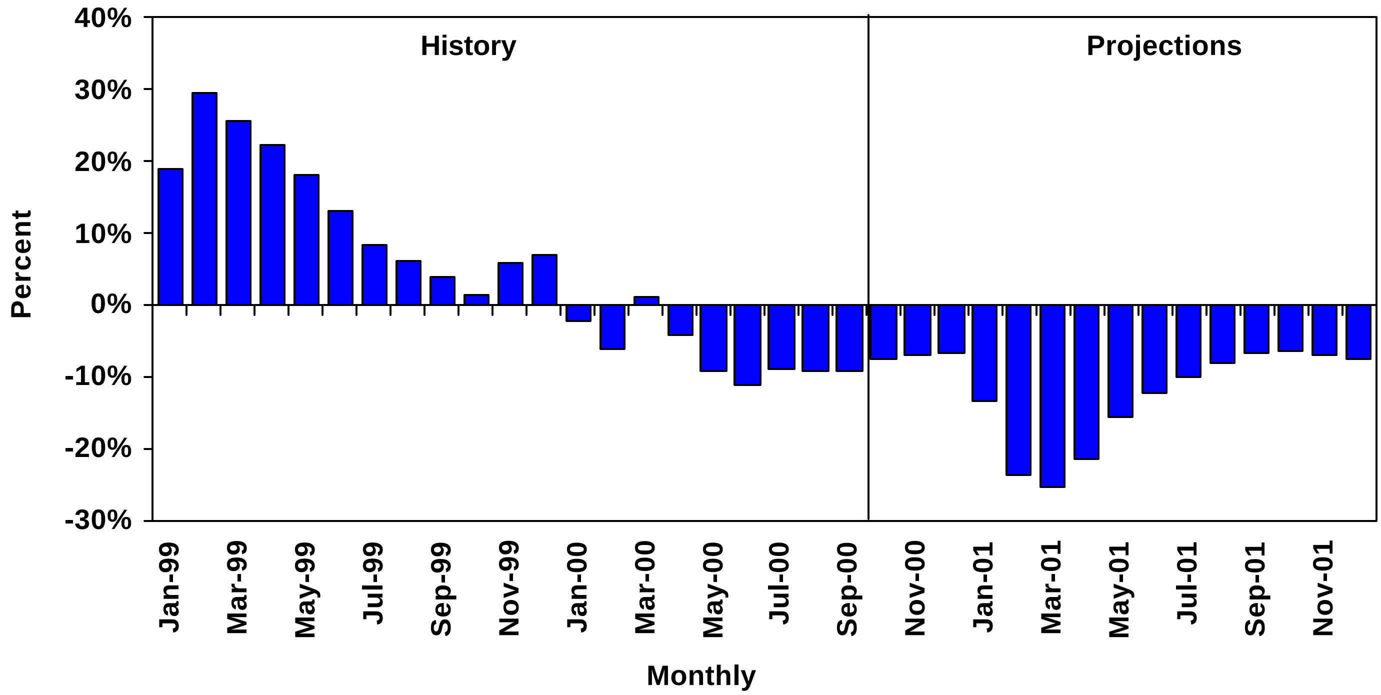


The forecast for overall natural gas demand in 2000 is a 4.0 percent annual growth rate. In 2001, the forecast is for a 2.7 percent growth rate (Figure 13), principally due to higher gas prices. The industrial sector is the leading sector for demand increases in 2000 at 9.3 percent, while electric utility demand is expected to decline by 4.5 percent. This dichotomy is due in large part to sales of electric generating plants by electric utilities to unregulated generating companies, fuel consumption by which is recorded by EIA in the industrial sector.

This winter, (October 2000 through March 2001) natural gas demand is expected to be up by 5.5 percent over last winter's demand under normal weather assumptions. Normal weather implies a 12 percent rise in heating degree-days compared with last winter, which was much warmer than normal.

U.S. Natural Gas Supply

Figure 14. Natural Gas in Storage **(Difference from Previous 5-Year Average)**



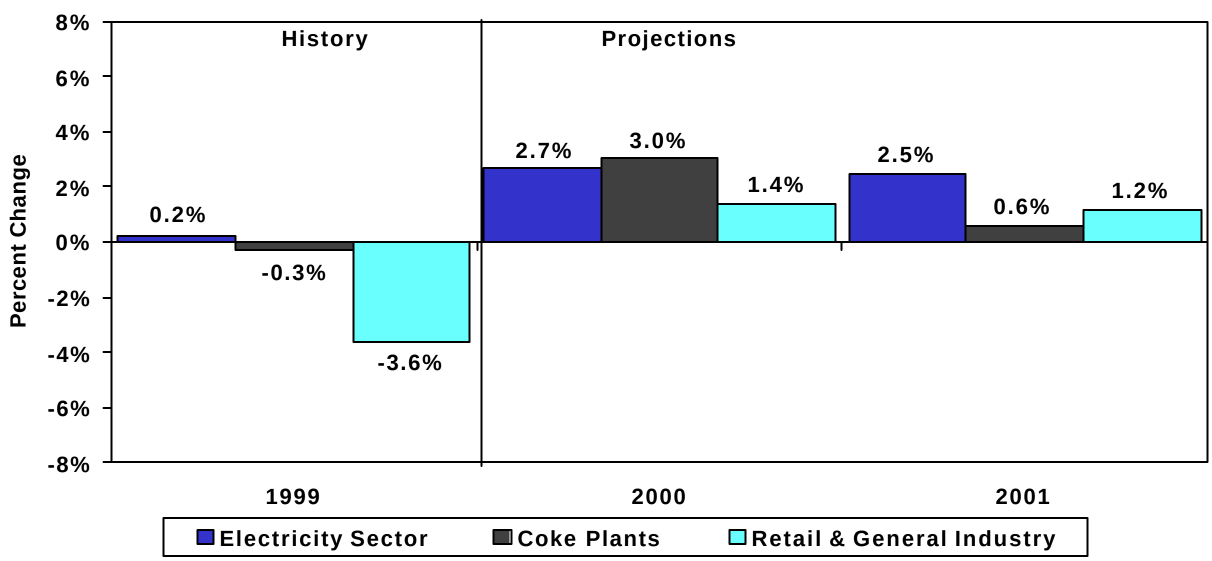
Several factors have come together to push spot gas prices up sharply and they have reversed the general downward trend in real gas prices (evident since the mid-1980's): U.S. gas production has slipped; expected demand is high under normal weather assumptions; gas storage levels are below normal (Figure 14), and alternative fuel (oil) markets are tight. Concerns focus particularly on working gas storage levels, which could be about 12 percent below last year at the start of the heating season. The high price of natural gas reflects the intense competition between current and future uses of gas supplies and has been a disincentive to increasing storage injections.

For now, we are continuing to maintain a conservative view of possible increases in domestic gas production for 2000 and 2001, with assumed increases of 0.2 percent and 1.3 percent, respectively, for this year and next. The effects of increased drilling for gas are not expected to appear in the form of significantly increased production until after the coming heating season. On the other hand, the U.S. natural gas rig count on September 29 was at a high of 806 rigs. Exploration and production budgets for many natural gas producers are expected to increase sharply in 2000 and 2001, spurred by higher prices and greatly improved current and expected revenues from producing assets. Although the gas rig count has been climbing for months, it takes 6 to 18 months for new production to get to the market following a period of heavy drilling. A significant increase in gas wellhead supplies is unlikely before mid-2001.

Net imports of natural gas are projected to rise by about 12 percent in 2001. During the winter months, net imports are about 10 percent higher than flows during the rest of the year and usually increase to full pipeline capacity. That capacity is scheduled to increase at the end of 2000 when the Alliance Pipeline will begin carrying gas from western Canada to the Midwest. Assuming that it will take several months before Alliance reaches its full capacity of 1.3 bcf per day, that pipeline may not fully contribute to advancing new gas supplies until the heating season is nearly over. Even if Alliance is near capacity at mid winter, it is likely that a substantial portion of the volumes contracted for delivery on the system will have been de-contracted from other systems, particularly TransCanada Pipeline System. Thus it is an important question as to just how significant Alliance will be with respect to net new supply from Canada.

U.S. Coal Demand and Supply

Figure 15. Annual Change in U.S. Coal Demand



Total coal demand is expected to increase by about 2.6 percent in 2000 and 2.3 percent in 2001, compared to the slight decline experienced in 1999 (Table 9 and Figure 15). Electric utility coal demand is expected to fall in 2000 by 3.3 percent. The decline in electric utility coal consumption is primarily an effect of the growth of non-utility electricity generation. Coal consumed at independent power producers (IPPs), which include former utility generating facilities sold under electricity deregulation, is expected to more than double in 2000 (increasing by 119 percent) from 45.9 million short tons to 100.5 million short tons. Total coal consumption by the electricity sector (utility and non-utility) is expected to grow by 2.7 percent in 2000 and 2.5 percent in 2001.

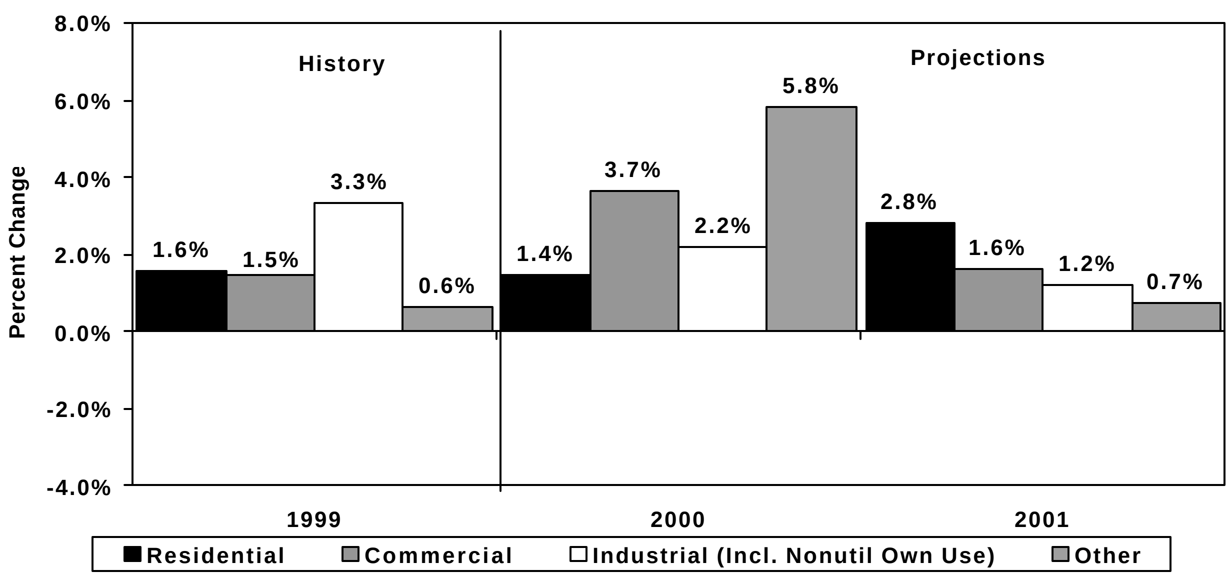
Demand for coal at coke plants is expected to remain near 29 million short tons throughout the forecast period because existing coke plants are already operating at or near capacity and most new steel production relies on non-coke methods (recycling and electric arc furnaces). Demand for coal by the retail and general industry sectors is projected at 71.3 million short tons in 2000, a 1.4 percent increase over 1999 demand. In 2001, demand in these sectors is expected to increase by 1.2 percent from the 2000 level.

U.S. coal exports are expected to remain weak over the forecast period. Exports are expected to decline slightly in 2000 (0.5 percent) though moderate growth is forecasted for 2001 (4.0 percent). Exports are expected to remain nearly 20 million short tons below 1998 levels of 78 million short tons. Projections call for 58.2 million short tons of coal exports in 2000 and 60.5 million short tons in 2001.

Coal production is expected to remain virtually flat at 1,094.6 million short tons in 2000. This follows the decline coal production experienced in 1999 (2.1 percent), which was primarily due to lower electric utility demand. Production is projected to increase by 2.1 percent in 2001 (1,117.8 million short tons).

U.S. Electricity Demand and Supply

Figure 16. Annual Changes in U. S. Electricity Demand



Total annual electricity demand growth is projected to be 2.5 percent in 2000. Demand growth is expected to be 1.9 percent in 2001. This is on track with average electricity growth between 1990 and 1998, which was about 2.0 percent per year.

This winter's heating degree-days (HDD) are assumed to be 11 percent above last winter's HDD, which were well below normal. This winter, total electricity demand is expected to be up by 2.8 percent under normal weather assumptions, driven by increased demand in the residential and commercial sectors, up by 4.6 and 3.9 percent, respectively.

Demand for electricity is seen as growing across all sectors in both 2000 and 2001, (Figure 16 and Table 10). Annual industrial electricity demand growth in both 2000 and 2001 is expected to average about 1 percent .

Non-utility sales of electricity to the utility sector are projected to rise significantly in 2000 and continue to rise in 2001 as generating facilities are sold to the industrial sector as a result of electricity sector deregulation. EIA accounts for these non-utility electricity generators in the industrial sector. Electricity generation by utilities is expected to decrease significantly from 1999 levels in both 2000 and 2001.

Summary of Important Terms

PETROLEUM PRICES

Refiner acquisition cost of crude oil (RAC): The average monthly cost of crude oil to U.S. refiners, including transportation and fees. The composite cost is the weighted average of domestic and imported crude oil costs. Typically, the imported RAC is about $1.50 per barrel below the monthly average spot price of West Texas Intermediate (WTI) crude oil and is within about $0.20 per barrel of the average monthly spot price of Brent crude oil. Unless otherwise stated, the imported RAC is what is referred to in this report as the "world oil price" or "average crude oil price."

Retail motor gasoline prices: The average pump prices for gasoline reported in the *Short-term Energy Outlook* are derived from the Energy Information Administration (EIA) form EIA-878, "Motor Gasoline Price Survey." The two series are: 1) average retail price of regular motor gasoline, self-service; 2) average retail price for all grades of motor gasoline, self-service. Both price series are for cash transactions. The historical values for these prices are reported on Table 16 of EIA's *Weekly Petroleum Status Report*.

Wholesale motor gasoline price: The monthly average price to refiners of motor gasoline (all types) sold to resellers; it is reported monthly on Table 4 of EIA's *Petroleum Marketing Monthly*.

Retail heating oil price: The cost of Number 2 distillate fuel oil to residences (less taxes). The retail heating oil price referred to in this report is from Table 18 of EIA's *Petroleum Marketing Monthly*.

PETROLEUM DEMAND and SUPPLY

Petroleum Demand (consumption/petroleum products supplied): For each product (gasoline, distillate, etc.), the amount supplied is calculated by summing production, imports, and net withdrawals from primary stocks and subtracting exports. Thus, petroleum demand is represented by the "disappearance" of product from the primary supply system. This demand definition coincides exactly with the term "product supplied" as used in EIA's *Petroleum Supply Monthly*.

Petroleum Stocks, primary: Stocks of crude oil or petroleum products held in storage at (or in) leases, refineries, natural gas processing plants, pipelines, tank farms, and bulk terminals. Crude oil that is in transit from Alaska or that is stored on Federal leases or in the Strategic Petroleum Reserve is included. These are the only stocks included in this report when petroleum inventories or inventory changes are discussed. Excluded are stocks of foreign origin that are stored in bonded warehouses.

Charts in this report displaying inventory levels of crude oil or petroleum products that provide the reader with actual inventory data compared to an “average" or "normal" range are constructed as follows: the actual stock levels are the actual reported end-of-month levels; the ranges are based on the most recent 3-year period running from January through December or from July through June. The ranges also reflect seasonal variation for the past 7 years. The seasonal factors, which determine the shape of the upper and lower curves, are estimated with a seasonal adjustment technique developed at the Bureau of Census (Census X–11). The seasonal factors are assumed to be stable (i.e., the same seasonal factor is used for each January during the 7-year period) and additive (i.e., the series is deseasonalized by subtracting the seasonal factor for the appropriate month from the reported inventory levels). The intent of deseasonalization is to remove only annual variation from the data. Thus, deseasonalized series would contain the same trends, cyclical components, and irregularities as the original data. The seasonal factors are updated annually in October, using the 7 most recent years’ final monthly data. The seasonal factors are used to deseasonalize data from the most recent 3-year period (January-December or July-June) in order to determine a deseasonalized average band. The average of the deseasonalized 36-month series is the midpoint of the band, and two standard deviations of the series (adjusting first for extreme points) is its width. When the seasonal factors are added back in (the upper curve is the midpoint plus one standard deviation plus the seasonal factor, and the lower curve is the midpoint minus one standard deviation plus the seasonal factor), the “average range” shown on the graphs reflects the actual data. The ranges are updated every 6 months in April and October.

NATURAL GAS

Wellhead Prices. Composite: The composite (i.e. composed of both contract and spot transactions) wellhead price of natural gas, calculated by dividing the total reported value at the wellhead by the total quantity produced as reported by the appropriate agencies of individual producing States and the U.S. Minerals Management Service, Department of the Interior. The price includes all costs prior to shipment from the lease, including gathering and compression costs, in addition to State production, severance, and similar charges. **Spot**: A transaction price for natural gas concluded "on the spot," that is, on a one-time prompt (immediate) basis, as opposed to a longer-term contract price obligating the seller to deliver the product at an agreed price over an extended period of time.

MACROECONOMIC

Gross Domestic Product (GDP): The total value of goods and services produced by labor and property located in the United States. As long as the labor and property are located in the United States, the supplier may be either U.S. residents or residents of foreign countries. Nominal GDP refers to current dollar value; real GDP refers to GDP corrected for inflation.

GDP Implicit Price Deflator: A byproduct of the price deflation of gross domestic product (GDP). It is derived as the ratio of current- to constant-dollar GDP. It is a weighted average of the detailed price indexes used in the deflation of GDP, but these indexes are combined, using weights that reflect the composition of GDP in each period. Thus, changes in the implicit price deflator reflect not only changes in prices but also changes in the composition of GDP. Corresponding current- and constant-dollar series are published by the U.S. Bureau of Economic Analysis, National Income and Product Accounts. The current base year for the deflator is 1996.

Manufacturing Production Index: A measure of nondurable and durable manufacturing production expressed as a percentage of output in a reference period (currently 1992). Data are published by the Federal Reserve System in the *Federal Reserve Bulletin*.

Employment: Employment data refer to persons on establishment payrolls who received pay for any part of the pay period including the 12th of the month (or the last day of the calendar month for government employees). The data exclude proprietors, the self-employed, unpaid volunteer or family workers, farm workers, and domestic workers. Salaried officers of corporations are included. Employment statistics are published by the U.S. Bureau of Labor Statistics in the Employment and Earnings report.

Consumer Price Index: A measure of the average change in prices paid by urban consumers for a fixed market basket of goods and services. The consumer price index is based on the prices of food, clothing, shelter, fuel, drugs, transportation fares, doctor and dentist's fees, and other goods and services that people buy for day-to-day living. All taxes directly associated with the purchase and use of items are included in the index. The consumer price index is published by the U.S. Bureau of Labor Statistics in the *Monthly Labor Review*.

Degree-days, cooling (CDD): For one day, the number of degrees that the average temperature for that day is above 65 degrees Fahrenheit. The daily average temperature is the mean of the maximum and minimum temperatures for a 24-hour period. As covered in this report, cooling degree-days in a period represent the sum of daily degree-day calculations over the period. Thus, national cooling degree-days for a month represent the weighted average of the daily cooling degree-days for the States, summed across all days in the month. The weights used are population shares unless otherwise noted.

Degree-days, heating (HDD): For one day, the number of degrees that the average temperature is below 65 degrees Fahrenheit. The daily average temperature is the mean of the maximum and minimum temperatures for a 24-hour period. As covered in this report, heating degree-days in a period represent the sum of daily degree-day calculations over the period. Thus, national heating degree-days for a month represent the weighted-average of the daily heating degree-days for the States, summed across all days in the month. The weights used are population shares unless otherwise noted.

British thermal unit (Btu): The quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit. In this report, Btu-equivalent energy values are calculated by multiplying estimated thermal content coefficients per physical unit for various products by the respective quantities. These are then aggregated across products to obtain, for example, total energy demand or supply variables.

TOTAL ENERGY

Total energy demand: The sum of fossil fuel consumed by the five sectors (residential, commercial, industrial, transportation, and electric utility), plus hydroelectric power, nuclear electric power, net imports of coal coke, and electricity generated for distribution from wood, waste, geothermal, wind, photovoltaic, and solar thermal energy. Includes estimates for renewable energy sources used in the residential, commercial, and industrial sectors.

GEOGRAPHICAL

Other Asia includes: Afghanistan, American Samoa, Bangladesh, Bhutan, Brunei, Burma, Cambodia, Cook Islands, Fiji, French Polynesia, Hong Kong (prior to July 1, 1997), India, Indonesia, Kiribati, North Korea, South Korea, Laos, Macau, Malaysia, Maldives, Mongolia, Nauru, Nepal, New Caledonia, Niue, Pakistan, Papua New Guinea, Philippines, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, U.S. Pacific Islands, Vanuatu, Vietnam, Wake Island, Western Samoa.

Latin America is defined as including all of the countries of Central and South America, plus Mexico, but excluding Puerto Rico and the U.S. Virgin Islands.

The Appalachian region States are: Alabama, Georgia, Eastern Kentucky, Maryland, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

The Interior region States are: Arkansas, Illinois, Indiana, Iowa, Kansas, Western Kentucky, Louisiana, Missouri, Oklahoma, and Texas.

The Western region States are: Alaska, Arizona, California, Colorado, Montana, New Mexico, North Dakota, Utah, Washington, and Wyoming.

Table 1. U.S. Macroeconomic and Weather Assumptions

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Macroeconomic [a]															
Real Gross Domestic Product (billion chained 1996 dollars - SAAR).........	**8730**	**8783**	**8906**	**9084**	**9192**	**9309**	*9391*	*9472*	*9563*	*9651*	*9739*	*9833*	**8876**	*9341*	*9696*
Percentage Change from Prior Year	**3.9**	**3.8**	**4.3**	**5.0**	**5.3**	**6.0**	*5.4*	*4.3*	*4.0*	*3.7*	*3.7*	*3.8*	**4.2**	*5.2*	*3.8*
Annualized Percent Change from Prior Quarter......................................	**3.5**	**2.4**	**5.6**	**8.0**	**4.7**	**5.1**	*3.5*	*3.5*	*3.9*	*3.6*	*3.7*	*3.9*			
GDP Implicit Price Deflator (Index, 1996=1.000)	**1.043**	**1.046**	**1.049**	**1.053**	**1.062**	**1.068**	*1.074*	*1.080*	*1.087*	*1.092*	*1.096*	*1.101*	**1.048**	*1.071*	*1.094*
Percentage Change from Prior Year	**1.5**	**1.5**	**1.5**	**1.5**	**1.8**	**2.1**	*2.4*	*2.6*	*2.4*	*2.2*	*2.1*	*2.0*	**1.5**	*2.2*	*2.2*
Real Disposable Personal Income (billion chained 1996 Dollars - SAAR)	**6264**	**6307**	**6342**	**6412**	**6443**	**6497**	*6555*	*6599*	*6709*	*6797*	*6871*	*6943*	**6331**	*6524*	*6830*
Percentage Change from Prior Year	**3.7**	**3.2**	**2.9**	**3.1**	**2.9**	**3.0**	*3.4*	*2.9*	*4.1*	*4.6*	*4.8*	*5.2*	**3.2**	*3.0*	*4.7*
Manufacturing Production (Index, 1996=1.000)	**1.148**	**1.162**	**1.175**	**1.195**	**1.216**	**1.237**	*1.255*	*1.274*	*1.284*	*1.295*	*1.307*	*1.317*	**1.170**	*1.245*	*1.301*
Percentage Change from Prior Year	**3.5**	**4.1**	**4.4**	**4.8**	**6.0**	**6.5**	*6.8*	*6.6*	*5.6*	*4.7*	*4.1*	*3.4*	**4.2**	*6.5*	*4.4*
OECD Economic Growth (percent) [b]													**2.6**	*3.6*	*3.0*
Weather [c]															
Heating Degree-Days															
U.S...	**2153**	**489**	**79**	**1448**	**2023**	**500**	*79*	*1623*	*2236*	*519*	*86*	*1622*	**4169**	*4225*	*4463*
New England	**3040**	**784**	**86**	**2042**	**3007**	**964**	*169*	*2239*	*3177*	*885*	*167*	*2238*	**5952**	*6379*	*6467*
Middle Atlantic..	**2816**	**628**	**68**	**1839**	**2713**	**710**	*93*	*2004*	*2895*	*701*	*105*	*2003*	**5351**	*5520*	*5703*
U.S. Gas-Weighted................................	**2275**	**517**	**85**	**1522**	**2115**	**522**	*83*	*1714*	*2354*	*555*	*90*	*1714*	**4399**	*4435*	*4714*
Cooling Degree-Days (U.S.)	**35**	**353**	**831**	**78**	**45**	**383**	*748*	*75*	*32*	*346*	*781*	*76*	**1297**	*1252*	*1235*

[a]Macroeconomic projections from DRI/McGraw-Hill model forecasts are seasonally adjusted at annual rates and modified as appropriate to the mid world oil price case.

[b]OECD: Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States. The Czech Republic, Hungary, Mexico, Poland, and South Korea are all members of OECD, but are not yet included in our OECD estimates.

[c]Population-weighted degree days. A degree day indicates the temperature variation from 65 degrees Fahrenheit (calculated as the simple average of the daily minimum and maximum temperatures) weighted by 1990 population.

SAAR: Seasonally-adjusted annualized rate.

Note: Historical data are printed in bold; forecasts are in italics.

Sources: Historical data: latest data available from: U.S. Department of Commerce, Bureau of Economic Analysis; U.S. Department of Commerce, National Oceanic and Atmospheric Administration; Federal Reserve System, *Statistical Release G.17(419)*. Projections of OECD growth are based on WEFA Group, "World Economic Outlook," Volume 1. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0900.

Table 2. U.S. Energy Indicators: Mid World Oil Price Case

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Macroeconomic [a]															
Real Fixed Investment (billion chained 1996 dollars-SAAR)	1574	1607	1638	1667	1731	1794	1814	1850	1879	1910	1933	1955	1621	1797	1919
Real Exchange Rate (index)	1.090	1.127	1.168	1.167	1.221	1.279	1.257	1.220	1.223	1.213	1.197	1.173	1.138	1.244	1.202
Business Inventory Change (billion chained 1996 dollars-SAAR)	-1.1	-9.5	3.5	7.6	10.3	7.4	8.8	8.6	6.5	6.9	6.8	5.5	0.1	8.8	6.4
Producer Price Index (index, 1982=1.000)	1.230	1.245	1.268	1.276	1.302	1.319	1.352	1.364	1.364	1.356	1.349	1.350	1.255	1.334	1.355
Consumer Price Index (index, 1982-1984=1.000)	1.648	1.662	1.672	1.684	1.701	1.716	1.730	1.741	1.748	1.753	1.759	1.766	1.667	1.722	1.757
Petroleum Product Price Index (index, 1982=1.000)	0.446	0.591	0.682	0.716	0.833	0.906	0.929	0.911	0.894	0.815	0.776	0.766	0.609	0.895	0.813
Non-Farm Employment (millions)	127.8	128.4	129.1	129.8	130.6	131.5	131.6	132.0	132.4	132.8	133.1	133.4	128.8	131.4	132.9
Commercial Employment (millions)	88.6	89.2	89.8	90.5	91.2	91.7	92.1	92.6	93.1	93.5	93.9	94.4	89.5	91.9	93.7
Total Industrial Production (index, 1996=1.000)	1.127	1.139	1.153	1.168	1.186	1.207	1.224	1.241	1.251	1.261	1.270	1.279	1.147	1.215	1.265
Housing Stock (millions)	115.4	115.8	116.0	116.1	116.3	116.8	116.8	116.5	116.8	117.1	117.4	117.8	115.8	116.6	117.3
Miscellaneous															
Gas Weighted Industrial Production (index, 1996=1.000)	1.062	1.060	1.068	1.091	1.096	1.096	1.099	1.103	1.112	1.121	1.131	1.141	1.070	1.098	1.126
Vehicle Miles Traveled [b] (million miles/day)	6731	7556	7706	7358	6820	7558	7698	7277	6921	7637	7819	7376	7341	7339	7441
Vehicle Fuel Efficiency (index, 1999=1.000)	0.991	0.992	1.007	1.006	0.997	1.007	1.001	1.003	1.002	1.004	1.009	1.001	0.999	1.002	1.004
Real Vehicle Fuel Cost (cents per mile)	2.98	3.35	3.51	3.76	4.16	4.29	4.27	4.26	4.08	3.92	3.83	3.85	3.40	4.24	3.92
Air Travel Capacity (mill. available ton-miles/day)	431.0	453.8	469.4	462.1	452.9	480.8	498.6	487.4	484.4	507.0	524.8	514.3	454.2	480.0	507.7
Aircraft Utilization (mill. revenue ton-miles/day)	242.2	264.2	277.5	266.0	254.9	283.6	297.7	283.8	278.6	297.4	311.5	296.7	262.6	280.0	296.2
Airline Ticket Price Index (index, 1982-1984=1.000)	2.130	2.186	2.180	2.254	2.309	2.419	2.489	2.506	2.517	2.505	2.488	2.496	2.188	2.431	2.502
Raw Steel Production (millions tons)	25.11	25.97	26.26	28.54	29.02	29.33	29.06	29.32	29.32	29.46	28.88	29.23	105.88	116.73	116.88

[a] Macroeconomic projections from DRI/McGraw-Hill model forecasts are seasonally adjusted at annual rates and modified as appropriate to the mid world oil price case.

[b] Includes all highway travel.

SAAR: Seasonally-adjusted annualized rate.

Note: Historical data are printed in bold; forecasts are in italics.

Sources: Historical data: latest data available from: U.S. Department of Commerce, Bureau of Economic Analysis; U.S. Department of Commerce, National Oceanic and Atmospheric Administration; Federal Reserve System, *Statistical Release* G.17(419); U.S. Department of Transportation; American Iron and Steel Institute. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0900.

Table 3. International Petroleum Supply and Demand: Mid World Oil Price Case

(Million Barrels per Day, Except OECD Commercial Stocks)

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Demand [a]															
OECD															
U.S. (50 States)	**19.2**	**19.2**	**19.8**	**19.8**	**19.1**	**19.3**	*20.0*	*20.0*	*19.7*	*19.8*	*20.2*	*20.4*	**19.5**	*19.6*	*20.0*
U.S. Territories	**0.3**	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	**0.3**	*0.4*	*0.4*
Canada	**1.9**	**1.9**	**2.0**	**2.0**	**1.9**	**1.9**	*2.0*	*2.0*	*2.0*	*1.9*	*2.1*	*2.0*	**1.9**	*1.9*	*2.0*
Europe	**15.2**	**13.8**	**14.1**	**15.0**	**14.5**	**13.7**	*14.5*	*15.1*	*14.9*	*14.0*	*14.5*	*15.2*	**14.5**	*14.5*	*14.6*
Japan	**6.2**	**5.0**	**5.2**	**5.9**	**6.0**	**5.1**	*5.3*	*5.7*	*6.2*	*5.1*	*5.3*	*5.7*	**5.6**	*5.5*	*5.6*
Australia and New Zealand	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	*1.0*	*1.1*	*1.0*	*1.0*	*1.0*	*1.1*	**1.0**	*1.0*	*1.0*
Total OECD	**43.8**	**41.2**	**42.4**	**44.0**	**42.8**	**41.3**	*43.1*	*44.3*	*44.2*	*42.1*	*43.4*	*44.8*	**42.8**	*42.9*	*43.6*
Non-OECD															
Former Soviet Union	**3.8**	**3.5**	**3.6**	**3.7**	**3.8**	**3.6**	*3.6*	*3.6*	*3.8*	*3.7*	*3.7*	*3.7*	**3.6**	*3.7*	*3.7*
Europe	**1.6**	**1.6**	**1.5**	**1.6**	**1.6**	**1.6**	*1.6*	*1.6*	*1.7*	*1.7*	*1.7*	*1.7*	**1.6**	*1.6*	*1.7*
China	**4.4**	**4.3**	**4.3**	**4.3**	**4.6**	**4.5**	*4.5*	*4.5*	*4.8*	*4.8*	*4.7*	*4.8*	**4.3**	*4.5*	*4.8*
Other Asia	**8.8**	**8.8**	**8.7**	**9.0**	**9.2**	**9.2**	*9.0*	*9.4*	*9.7*	*9.7*	*9.4*	*9.9*	**8.8**	*9.2*	*9.7*
Other Non-OECD	**13.4**	**13.6**	**13.7**	**13.7**	**13.7**	**14.0**	*14.1*	*14.0*	*14.2*	*14.4*	*14.5*	*14.5*	**13.6**	*14.0*	*14.4*
Total Non-OECD	**31.9**	**31.8**	**31.7**	**32.3**	**32.9**	**33.0**	*32.8*	*33.2*	*34.2*	*34.3*	*34.0*	*34.5*	**31.9**	*33.0*	*34.2*
Total World Demand	**75.7**	**73.1**	**74.1**	**76.3**	**75.7**	**74.3**	*76.0*	*77.5*	*78.4*	*76.4*	*77.4*	*79.2*	**74.8**	*75.9*	*77.9*
Supply [b]															
OECD															
U.S. (50 States)	**8.8**	**8.9**	**9.0**	**9.3**	**9.1**	**9.1**	*9.0*	*9.2*	*9.2*	*9.2*	*9.1*	*9.2*	**9.0**	*9.1*	*9.2*
Canada	**2.6**	**2.6**	**2.6**	**2.7**	**2.7**	**2.7**	*2.6*	*2.7*	*2.7*	*2.7*	*2.8*	*2.8*	**2.6**	*2.7*	*2.7*
North Sea [c]	**6.3**	**6.0**	**6.2**	**6.7**	**6.6**	**6.2**	*6.4*	*6.8*	*6.5*	*6.3*	*6.3*	*6.5*	**6.3**	*6.5*	*6.4*
Other OECD	**1.5**	**1.5**	**1.5**	**1.6**	**1.7**	**1.7**	*1.8*	*1.8*	*1.8*	*1.7*	*1.7*	*1.8*	**1.5**	*1.7*	*1.8*
Total OECD	**19.2**	**19.0**	**19.3**	**20.2**	**20.2**	**19.7**	*19.8*	*20.4*	*20.2*	*19.9*	*19.8*	*20.3*	**19.4**	*20.0*	*20.1*
Non-OECD															
OPEC	**30.4**	**28.9**	**29.2**	**28.7**	**29.3**	**30.7**	*31.9*	*32.4*	*32.2*	*32.0*	*32.0*	*32.1*	**29.3**	*31.1*	*32.1*
Former Soviet Union	**7.3**	**7.3**	**7.5**	**7.5**	**7.6**	**7.7**	*7.8*	*7.9*	*8.0*	*8.0*	*8.1*	*8.2*	**7.4**	*7.8*	*8.1*
China	**3.2**	**3.2**	**3.2**	**3.2**	**3.3**	**3.3**	*3.3*	*3.3*	*3.3*	*3.3*	*3.3*	*3.3*	**3.2**	*3.3*	*3.3*
Mexico	**3.6**	**3.4**	**3.3**	**3.3**	**3.5**	**3.5**	*3.5*	*3.5*	*3.6*	*3.6*	*3.6*	*3.6*	**3.4**	*3.5*	*3.6*
Other Non-OECD	**11.3**	**11.2**	**11.2**	**11.2**	**11.2**	**11.2**	*11.3*	*11.4*	*11.4*	*11.5*	*11.5*	*11.6*	**11.2**	*11.3*	*11.5*
Total Non-OECD	**55.7**	**54.0**	**54.5**	**54.0**	**54.8**	**56.4**	*57.7*	*58.5*	*58.4*	*58.3*	*58.5*	*58.8*	**54.5**	*56.9*	*58.5*
Total World Supply	**74.9**	**72.9**	**73.8**	**74.2**	**75.0**	**76.1**	*77.5*	*78.9*	*78.6*	*78.2*	*78.3*	*79.1*	**73.9**	*76.9*	*78.5*
Stock Changes															
Net Stock Withdrawals or Additions (-)															
U.S. (50 States including SPR)	**0.3**	**-0.2**	**0.3**	**1.3**	**0.1**	**-0.6**	*-0.1*	*0.5*	*0.2*	*-0.6*	*-0.4*	*0.2*	**0.4**	*0.0*	*-0.1*
Other	**0.5**	**0.4**	**0.0**	**0.8**	**0.5**	**-1.1**	*-1.5*	*-1.9*	*-0.4*	*-1.2*	*-0.5*	*-0.1*	**0.4**	*-1.0*	*-0.5*
Total Stock Withdrawals	**0.8**	**0.1**	**0.3**	**2.1**	**0.7**	**-1.7**	*-1.6*	*-1.4*	*-0.2*	*-1.8*	*-0.9*	*0.1*	**0.8**	*-1.0*	*-0.7*
OECD Comm. Stocks, End (bill. bbls.)	**2.8**	**2.8**	**2.8**	**2.6**	**2.6**	**2.6**	*2.7*	*2.7*	*2.7*	*2.8*	*2.9*	*2.8*	**2.6**	*2.8*	*2.8*
Non-OPEC Supply	**44.6**	**44.0**	**44.5**	**45.4**	**45.7**	**45.4**	*45.6*	*46.5*	*46.4*	*46.2*	*46.3*	*47.0*	**44.6**	*45.8*	*46.5*
Net Exports from Former Soviet Union	**3.5**	**3.8**	**3.9**	**3.8**	**3.9**	**4.1**	*4.2*	*4.3*	*4.1*	*4.3*	*4.4*	*4.5*	**3.8**	*4.1*	*4.4*

[a]Demand for petroleum by the OECD countries is synonymous with "petroleum product supplied," which is defined in the glossary of the EIA *Petroleum Supply Monthly,* DOE/EIA-0109. Demand for petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel and loss, and bunkering.

[b]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources.

[c]Includes offshore supply from Denmark, Germany, the Netherlands, Norway, and the United Kingdom.

OECD: Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States. The Czech Republic, Hungary, Mexico, Poland, and South Korea are all members of OECD, but are not yet included in our OECD estimates.

OPEC: Organization of Petroleum Exporting Countries: Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

SPR: Strategic Petroleum Reserve

Former Soviet Union: Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Notes: Minor discrepancies with other published EIA historical data are due to rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Energy Information Administration: latest data available from EIA databases supporting the following reports: *International Petroleum Statistics Report*, DOE/EIA-0520; Organization for Economic Cooperation and Development, Annual and Monthly Oil Statistics Database.

Table 4. U. S. Energy Prices

(Nominal Dollars)

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Imported Crude Oil Prices															
Imported Average[a]	10.91	15.44	19.63	23.01	26.84	26.57	29.65	28.26	26.50	24.34	24.02	23.61	17.21	27.86	24.58
WTI[b] Spot Average	13.07	17.65	21.73	24.56	28.82	28.78	31.61	30.35	28.51	26.33	26.00	25.59	19.25	29.89	26.61
Natural Gas Wellhead															
(dollars per thousand cubic feet)	1.74	2.04	2.27	2.26	2.26	2.97	3.66	4.57	4.39	3.59	3.31	3.72	2.08	3.37	3.75
Petroleum Products															
Gasoline Retail [c] (dollars per gallon)															
All Grades	0.99	1.17	1.25	1.30	1.44	1.57	1.56	1.51	1.45	1.45	1.44	1.39	1.18	1.52	1.43
Regular Unleaded	0.95	1.13	1.21	1.26	1.40	1.53	1.52	1.47	1.41	1.42	1.40	1.35	1.14	1.48	1.40
No. 2 Diesel Oil, Retail															
(dollars per gallon)	0.97	1.08	1.18	1.26	1.42	1.41	1.51	1.57	1.50	1.39	1.35	1.35	1.12	1.48	1.39
No. 2 Heating Oil, Wholesale															
(dollars per gallon)	0.36	0.44	0.56	0.65	0.85	0.78	0.91	0.91	0.84	0.74	0.71	0.72	0.51	0.87	0.76
No. 2 Heating Oil, Retail															
(dollars per gallon)	0.80	0.82	0.86	1.01	1.31	1.17	1.25	1.38	1.36	1.18	1.06	1.12	0.88	1.31	1.23
No. 6 Residual Fuel Oil, Retail [d]															
(dollars per barrel)	11.28	14.03	17.94	21.06	23.64	24.43	27.03	26.93	25.44	22.38	21.82	22.67	15.92	25.60	23.13
Electric Utility Fuels															
Coal															
(dollars per million Btu)	1.24	1.23	1.21	1.20	1.21	1.20	1.19	1.19	1.20	1.22	1.20	1.19	1.22	1.20	1.20
Heavy Fuel Oil [e]															
(dollars per million Btu)	1.73	2.26	2.82	3.17	3.74	4.08	4.47	4.33	3.93	3.62	3.65	3.65	2.39	4.22	3.72
Natural Gas															
(dollars per million Btu)	2.19	2.42	2.74	2.82	2.85	3.71	4.28	5.14	5.09	4.19	3.90	4.34	2.57	4.00	4.25
Other Residential															
Natural Gas															
(dollars per thousand cubic feet)	6.07	6.86	8.64	6.85	6.48	7.73	9.77	8.61	8.54	8.94	9.93	8.24	6.63	7.57	8.63
Electricity															
(cents per kilowatthour)	7.76	8.25	8.40	8.10	7.76	8.34	8.64	8.22	7.83	8.41	8.66	8.22	8.14	8.25	8.29

[a] Refiner acquisition cost (RAC) of imported crude oil.
[b] West Texas Intermediate.
[c] Average self-service cash prices.
[d] Average for all sulfur contents.
[e] Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Data are estimated for the first quarter of 2000. Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Marketing Monthly*, DOE/EIA-0380; *Natural Gas Monthly*, DOE/EIA-0130; *Monthly Energy Review*, DOE/EIA-0035; *Electric Power Monthly*, DOE/EIA-0226.

Table 5. U.S. Petroleum Supply and Demand: Mid World Oil Price Case

(Million Barrels per Day, Except Closing Stocks)

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Supply															
Crude Oil Supply															
Domestic Production [a]	5.94	5.84	5.79	5.96	5.86	5.84	5.79	5.87	5.95	5.92	5.85	5.91	5.88	5.84	5.91
Alaska	1.13	1.04	0.98	1.05	1.02	0.97	0.89	0.95	1.02	1.01	0.97	1.00	1.05	0.96	1.00
Lower 48	4.80	4.80	4.82	4.91	4.84	4.87	4.90	4.92	4.92	4.90	4.89	4.91	4.83	4.88	4.91
Net Imports (including SPR) [b]	8.43	8.90	8.85	8.27	8.12	9.14	9.32	8.90	8.78	9.48	9.70	9.31	8.61	8.87	9.32
Other SPR Supply	0.01	0.03	0.01	0.00	0.02	0.17	0.07	0.07	0.00	0.00	0.16	0.16	0.01	0.08	0.08
SPR Stock Withdrawn or Added (-)	-0.01	-0.03	-0.01	0.09	-0.02	0.01	-0.03	0.29	0.00	0.00	-0.16	-0.16	0.01	0.06	-0.08
Other Stock Withdrawn or Added (-)	-0.24	0.15	0.31	0.21	-0.14	0.03	0.11	-0.08	-0.20	-0.05	0.16	0.02	0.11	-0.02	-0.02
Product Supplied and Losses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unaccounted-for Crude Oil	0.30	0.15	0.27	0.05	0.32	0.40	0.51	0.21	0.21	0.22	0.22	0.21	0.19	0.36	0.21
Total Crude Oil Supply	14.42	15.01	15.22	14.57	14.16	15.42	15.70	15.19	14.74	15.57	15.77	15.29	14.80	15.12	15.34
Other Supply															
NGL Production	1.72	1.82	1.90	1.95	1.97	1.94	1.92	1.96	1.98	1.97	1.96	2.01	1.85	1.95	1.98
Other Hydrocarbon and Alcohol Inputs	0.37	0.37	0.38	0.38	0.37	0.40	0.38	0.40	0.38	0.37	0.36	0.39	0.38	0.39	0.37
Crude Oil Product Supplied	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing Gain	0.82	0.86	0.90	0.97	0.94	0.95	0.92	0.92	0.87	0.92	0.93	0.90	0.89	0.93	0.91
Net Product Imports [c]	1.34	1.52	1.41	0.92	1.35	1.18	1.19	1.27	1.32	1.47	1.51	1.42	1.30	1.25	1.43
Product Stock Withdrawn or Added (-)	0.54	-0.36	0.00	1.03	0.31	-0.62	-0.17	0.25	0.42	-0.54	-0.38	0.37	0.30	-0.06	-0.03
Total Supply	19.21	19.23	19.80	19.83	19.09	19.27	19.94	20.00	19.70	19.75	20.15	20.38	19.52	19.58	20.00
Demand															
Motor Gasoline	7.95	8.60	8.61	8.55	8.01	8.47	8.65	8.48	8.09	8.59	8.73	8.61	8.43	8.40	8.51
Jet Fuel	1.69	1.63	1.68	1.69	1.64	1.67	1.76	1.79	1.78	1.75	1.80	1.83	1.67	1.71	1.79
Distillate Fuel Oil	3.71	3.38	3.45	3.75	3.75	3.55	3.61	3.78	3.97	3.63	3.57	3.82	3.57	3.67	3.75
Residual Fuel Oil	0.93	0.78	0.84	0.78	0.73	0.74	0.89	0.75	0.87	0.79	0.79	0.76	0.83	0.78	0.80
Other Oils [d]	4.93	4.84	5.23	5.05	4.96	4.84	5.04	5.19	4.99	4.99	5.26	5.36	5.01	5.01	5.15
Total Demand	19.21	19.23	19.80	19.83	19.09	19.27	19.95	19.98	19.70	19.75	20.15	20.38	19.52	19.58	20.00
Total Petroleum Net Imports	9.77	10.43	10.27	9.19	9.47	10.33	10.51	10.17	10.11	10.95	11.21	10.72	9.91	10.12	10.75
Closing Stocks (million barrels)															
Crude Oil (excluding SPR)	345	332	304	284	297	294	285	292	310	315	300	298	284	292	298
Total Motor Gasoline	217	217	207	193	205	211	192	199	204	203	198	204	193	199	204
Finished Motor Gasoline	169	173	162	154	158	165	150	158	158	162	157	163	154	158	163
Blending Components	48	44	45	39	47	45	42	42	46	41	41	41	39	42	41
Jet Fuel	42	46	49	41	41	44	44	41	39	42	43	41	41	41	41
Distillate Fuel Oil	125	133	145	125	96	106	118	127	95	108	129	132	125	127	132
Residual Fuel Oil	40	42	41	36	36	37	37	41	36	36	38	39	36	41	39
Other Oils [e]	280	298	294	246	235	271	294	253	250	286	301	258	246	253	258
Total Stocks (excluding SPR)	1048	1068	1039	926	910	964	969	953	934	988	1008	972	926	953	972
Crude Oil in SPR	572	575	575	567	569	569	572	545	545	545	560	575	567	545	575
Heating Oil Reserve	0	0	0	0	0	0	0	2	2	2	2	2	0	2	2
Total Stocks (including SPR)	1620	1642	1615	1493	1479	1533	1541	1499	1480	1533	1569	1547	1493	1499	1547

[a]Includes lease condensate.

[b]Net imports equals gross imports plus SPR imports minus exports.

[c]Includes finished petroleum products, unfinished oils, gasoline blending components, and natural gas plant liquids for processing.

[d]Includes crude oil product supplied, natural gas liquids, liquefied refinery gas, other liquids, and all finished petroleum products except motor gasoline, jet fuel, distillate, and residual fuel oil.

[e]Includes stocks of all other oils, such as aviation gasoline, kerosene, natural gas liquids (including ethane), aviation gasoline blending components, naphtha and other oils for petrochemical feedstock use, special naphthas, lube oils, wax, coke, asphalt, road oil, and miscellaneous oils.

SPR: Strategic Petroleum Reserve

NGL: Natural Gas Liquids

Notes: Minor discrepancies with other EIA published historical data are due to rounding, with the following exception: recent petroleum demand and supply data displayed here reflect the incorporation of resubmissions of the data as reported in EIA's *Petroleum Supply Monthly*, Table C1. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109, and *Weekly Petroleum Status Report*, DOE/EIA-0208.

Table 6. Approximate Energy Demand Sensitivities[a] for the STIFS[b] Model

(Percent Deviation Base Case)

Demand Sector	+1% GDP	+ 10% Prices		+ 10% Weather [e]	
		Crude Oil [c]	N.Gas Wellhead [d]	Fall/Winter [f]	Spring/Summer [f]
Petroleum					
Total..	0.6%	-0.3%	0.1%	1.1%	0.1%
Motor Gasoline	0.1%	-0.3%	0.0%	0.0%	0.0%
Distillate Fuel...........................	0.8%	-0.2%	0.0%	2.7%	0.1%
Residual Fuel...........................	1.6%	-3.4%	2.6%	2.0%	2.7%
Natural Gas					
Total..	1.1%	0.3%	-0.4%	4.4%	1.0%
Residential..............................	0.1%	0.0%	0.0%	8.2%	0.0%
Commercial.............................	0.9%	0.0%	0.0%	7.3%	0.0%
Industrial.................................	1.7%	0.2%	-0.5%	1.3%	0.0%
Electric Utility	1.8%	1.6%	-1.5%	1.0%	4.0%
Coal					
Total..	0.7%	0.0%	0.0%	1.7%	1.7%
Electric Utility	0.6%	0.0%	0.0%	1.9%	1.9%
Electricity					
Total..	0.6%	0.0%	0.0%	1.5%	1.7%
Residential..............................	0.1%	0.0%	0.0%	3.2%	3.6%
Commercial.............................	0.9%	0.0%	0.0%	1.0%	1.4%
Industrial.................................	0.8%	0.0%	0.0%	0.3%	0.2%

[a]Percent change in demand quantity resulting from specified percent changes in model inputs.

[b]Short-Term Integrated Forecasting System.

[c]Refiner acquisitions cost of imported crude oil.

[d]Average unit value of marketed natural gas production reported by States.

[e]Refers to percent changes in degree-days.

[f]Response during fall/winter period(first and fourth calendar quarters) refers to change in heating degree-days. Response during the spring/summer period (second and third calendar quarters) refers to change in cooling degree-days.

Table 7. Forecast Components for U.S. Crude Oil Production

(Million Barrels per Day)

	High Price Case	Low Price Case	Difference		
			Total	Uncertainty	Price Impact
United States	*6.18*	*5.55*	*0.63*	*0.08*	*0.55*
Lower 48 States...	*5.17*	*4.47*	*0.60*	*0.07*	*0.53*
Alaska...	*1.01*	*0.98*	*0.04*	*0.02*	*0.02*

Note: Components provided are for the fourth quarter 2001. Totals may not add to sum of components due to independent rounding.
Source: Energy Information Administration, Office of Oil and Gas, Reserves and Natural Gas Division.

Table 8. U.S. Natural Gas Supply and Demand: Mid world Oil Price Case

(Trillion Cubic Feet)

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Supply															
Total Dry Gas Production	4.69	4.66	4.64	4.67	4.60	4.66	4.72	4.72	4.72	4.73	4.75	4.75	18.66	18.70	18.94
Net Imports	0.83	0.79	0.87	0.88	0.87	0.80	0.87	0.92	0.95	0.93	1.00	1.00	3.38	3.46	3.88
Supplemental Gaseous Fuels	0.03	0.02	0.02	0.03	0.03	0.02	0.03	0.03	0.04	0.03	0.03	0.03	0.10	0.11	0.12
Total New Supply	5.55	5.48	5.54	5.58	5.50	5.48	5.62	5.67	5.70	5.69	5.78	5.78	22.14	22.27	22.95
Working Gas in Storage															
Opening	2.73	1.43	2.16	2.88	2.51	1.15	1.71	2.53	2.20	0.86	1.68	2.60	2.73	2.51	2.20
Closing	1.43	2.16	2.88	2.51	1.15	1.71	2.53	2.20	0.86	1.68	2.60	2.18	2.51	2.20	2.18
Net Withdrawals	1.30	-0.73	-0.73	0.38	1.36	-0.56	-0.82	0.33	1.34	-0.83	-0.92	0.42	0.22	0.31	0.02
Total Supply	6.85	4.75	4.81	5.95	6.86	4.93	4.79	6.00	7.04	4.87	4.86	6.20	22.36	22.58	22.97
Balancing Item [a]	-0.08	-0.04	-0.32	-0.56	0.02	0.02	-0.12	-0.27	0.18	0.09	-0.09	-0.33	-1.00	-0.36	-0.15
Total Primary Supply	6.77	4.70	4.49	5.40	6.87	4.94	4.67	5.74	7.22	4.96	4.77	5.87	21.36	22.22	22.82
Demand															
Lease and Plant Fuel	0.31	0.31	0.31	0.31	0.30	0.31	0.31	0.31	0.31	0.31	0.31	0.31	1.23	1.23	1.23
Pipeline Use	0.20	0.14	0.13	0.16	0.21	0.15	0.14	0.17	0.21	0.14	0.13	0.17	0.64	0.66	0.65
Residential	2.24	0.80	0.38	1.27	2.20	0.77	0.37	1.41	2.42	0.85	0.38	1.42	4.69	4.75	5.06
Commercial	1.25	0.58	0.42	0.80	1.24	0.61	0.43	0.89	1.39	0.62	0.43	0.90	3.06	3.17	3.35
Industrial (Incl. Nonutility Use)	2.24	2.03	2.10	2.27	2.36	2.28	2.36	2.43	2.45	2.27	2.45	2.52	8.63	9.44	9.69
Electric Utilities	0.53	0.85	1.15	0.59	0.56	0.83	1.06	0.52	0.45	0.77	1.07	0.55	3.11	2.97	2.83
Total Demand	6.77	4.70	4.49	5.40	6.87	4.94	4.67	5.74	7.22	4.96	4.77	5.87	21.36	22.22	22.82

[a] The balancing item represents the difference between the sum of the components of natural gas supply and the sum of components of natural gas demand.

Notes: Minor discrepancies with other EIA published historical data are due to rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Oil and Gas, Reserves and Natural Gas Division.

Table 9. U.S. Coal Supply and Demand: Mid World Oil Price Case

(Million Short Tons)

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Supply															
Production	283.5	264.0	273.9	272.6	274.1	260.2	276.3	284.1	272.7	282.9	277.2	285.0	1094.0	1094.6	1117.8
Appalachia	114.8	103.4	103.0	102.1	109.5	105.2	106.1	104.1	106.9	106.3	99.5	102.2	423.3	424.9	414.8
Interior	40.4	40.8	42.4	38.9	36.1	35.2	41.3	38.7	35.7	40.5	39.5	37.0	162.5	151.2	152.7
Western	128.3	119.8	128.5	131.6	128.5	119.8	128.9	141.3	130.2	136.1	138.2	145.7	508.2	518.5	550.2
Primary Stock Levels [a]															
Opening	36.5	42.4	41.5	35.1	36.4	41.3	41.9	35.5	36.4	41.3	41.9	35.5	36.5	36.4	36.4
Closing	42.4	41.5	35.1	36.4	41.3	41.9	35.5	36.4	41.3	41.9	35.5	34.6	36.4	36.4	34.6
Net Withdrawals	-5.8	0.8	6.5	-1.3	-4.9	-0.6	6.4	-0.9	-4.9	-0.6	6.4	0.9	0.2	(S)	1.7
Imports	2.2	2.1	2.4	2.4	2.8	2.7	2.9	2.6	2.9	2.9	2.9	2.9	9.1	11.0	11.6
Exports	13.0	14.4	16.1	15.0	13.6	14.4	15.0	15.2	14.9	15.1	15.3	15.2	58.5	58.2	60.5
Total Net Domestic Supply	267.0	252.5	266.6	258.7	258.4	248.0	270.5	270.6	255.9	270.1	271.1	273.5	1044.8	1047.5	1070.6
Secondary Stock Levels [b]															
Opening	129.4	143.3	151.9	139.7	143.5	139.8	133.2	121.8	129.1	118.0	130.4	115.8	129.4	143.5	129.1
Closing	143.3	151.9	139.7	143.5	139.8	133.2	121.8	129.1	118.0	130.4	115.8	121.8	143.5	129.1	121.8
Net Withdrawals	-13.9	-8.6	12.2	-3.8	3.7	6.6	11.4	-7.3	11.0	-12.4	14.6	-6.0	-14.1	14.4	7.3
Waste Coal Supplied to IPPs [c]	2.1	2.2	2.6	2.8	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	9.7	12.2	12.2
Total Supply	255.2	246.1	281.4	257.6	265.2	257.6	285.0	266.4	270.0	260.8	288.8	270.6	1040.4	1074.2	1090.1
Demand															
Coke Plants	6.8	7.1	7.0	7.2	7.3	7.2	7.1	7.3	7.3	7.3	7.2	7.3	28.1	29.0	29.1
Electricity Production															
Electric Utilities	216.4	213.8	247.3	216.7	214.1	202.1	234.4	214.1	219.0	212.3	237.1	217.5	894.1	864.6	885.9
Nonutilities (Excl. Cogen.) [d]	8.4	10.3	12.3	15.0	24.6	23.6	26.8	25.5	25.2	24.2	27.5	26.1	45.9	100.5	102.9
Retail and General Industry	18.6	17.1	16.9	17.6	18.1	16.7	17.0	19.5	18.5	17.0	17.0	19.7	70.3	71.3	72.2
Total Demand [e]	250.2	248.3	283.6	256.5	264.1	249.6	285.4	266.4	270.0	260.8	288.8	270.6	1038.5	1065.4	1090.1
Discrepancy [f]	5.0	-2.1	-2.1	1.2	1.1	8.0	-0.4	0.0	0.0	0.0	0.0	0.0	1.9	8.7	0.0

[a] Primary stocks are held at the mines, preparation plants, and distribution points.

[b] Secondary stocks are held by users. It includes an estimate of stocks held at utility plants sold to nonutility generators.

[c] Estimated independent power producers' (IPPs) consumption of waste coal. This item includes waste coal and coal slurry reprocessed into briquettes.

[d] Estimates of coal consumption by IPPs, supplied by the Office of Coal, Nuclear, Electric, and Alternate Fuels, Energy Information Administration (EIA). Quarterly coal consumption estimates for 1999 and projections for 2000 and 2001 are based on (1) estimated consumption by utility power plants sold to nonutility generators during 1998 and 1999, and (2) annual coal-fired generation at nonutilities from Form EIA-867 (Annual Nonutility Power Producer Report).

[e] Total Demand includes estimated IPP consumption.

[f] The discrepancy reflects an unaccounted-for shipper and receiver reporting difference, assumed to be zero in the forecast period.

Notes: Rows and columns may not add due to independent rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Quarterly Coal Report*, DOE/EIA-0121, and *Electric Power Monthly*, DOE/EIA-0226. Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Coal, Nuclear, Electric and Alternate Fuels.

Table 10. U.S. Electricity Supply and Demand: Mid World Oil Price Case

(Billion Kilowatt-hours)

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Supply															
Net Utility Generation															
Coal	**430.0**	**423.8**	**487.6**	**426.2**	**425.7**	**401.2**	*463.3*	*423.7*	*436.5*	*423.8*	*473.2*	*431.4*	**1767.7**	*1713.9*	*1765.0*
Petroleum	**25.7**	**22.1**	**27.4**	**11.7**	**11.0**	**16.4**	*21.9*	*15.9*	*22.2*	*20.9*	*24.4*	*17.6*	**86.9**	*65.1*	*85.2*
Natural Gas	**51.5**	**80.7**	**107.5**	**56.7**	**54.4**	**79.1**	*100.4*	*49.5*	*42.6*	*73.2*	*101.3*	*51.8*	**296.4**	*283.5*	*269.0*
Nuclear	**181.2**	**166.1**	**195.0**	**182.6**	**185.0**	**177.4**	*197.3*	*179.7*	*186.9*	*170.9*	*195.7*	*175.8*	**725.0**	*739.3*	*729.2*
Hydroelectric	**83.4**	**79.8**	**69.9**	**60.9**	**66.9**	**73.0**	*62.7*	*61.3*	*70.5*	*74.6*	*62.1*	*61.1*	**293.9**	*263.9*	*268.3*
Geothermal and Other [a]	**1.6**	**1.0**	**0.6**	**0.5**	**0.5**	**0.6**	*0.6*	*0.6*	*0.5*	*0.5*	*0.6*	*0.6*	**3.7**	*2.3*	*2.2*
Subtotal	**773.4**	**773.6**	**888.0**	**738.7**	**743.4**	**747.6**	*846.2*	*730.7*	*759.3*	*763.9*	*857.4*	*738.2*	**3173.7**	*3067.9*	*3118.8*
Nonutility Generation [b]															
Coal	**19.4**	**22.9**	**32.4**	**39.2**	**55.2**	**58.5**	*60.2*	*57.6*	*56.2*	*53.1*	*61.7*	*59.0*	**113.9**	*231.4*	*230.0*
Petroleum	**7.8**	**8.7**	**8.7**	**6.9**	**11.1**	**8.8**	*8.1*	*9.1*	*7.7*	*7.5*	*8.1*	*9.1*	**32.1**	*37.0*	*32.5*
Natural Gas	**53.2**	**58.6**	**77.7**	**69.9**	**66.9**	**76.0**	*88.6*	*79.7*	*75.4*	*76.0*	*101.0*	*90.8*	**259.5**	*311.3*	*343.3*
Other Gaseous Fuels [c]	**2.0**	**2.2**	**2.9**	**2.6**	**2.5**	**2.8**	*2.0*	*2.3*	*2.0*	*1.9*	*2.1*	*2.3*	**9.5**	*9.6*	*8.2*
Nuclear	**0.0**	**0.0**	**1.1**	**2.1**	**5.2**	**5.0**	*5.2*	*5.2*	*5.2*	*5.1*	*5.1*	*5.2*	**3.2**	*20.5*	*20.5*
Hydroelectric	**3.7**	**3.8**	**2.9**	**3.1**	**3.9**	**5.0**	*2.7*	*3.2*	*2.8*	*2.8*	*2.8*	*3.2*	**13.5**	*14.8*	*11.7*
Geothermal and Other [d]	**19.6**	**21.4**	**23.5**	**21.2**	**21.8**	**22.2**	*22.9*	*25.5*	*21.8*	*21.1*	*23.2*	*24.0*	**85.7**	*92.4*	*90.1*
Subtotal	**105.6**	**117.6**	**149.2**	**145.0**	**166.6**	**178.3**	*189.7*	*182.5*	*171.2*	*167.5*	*204.0*	*193.7*	**517.4**	*717.0*	*736.3*
Total Generation	**879.0**	**891.2**	**1037.2**	**883.6**	**910.0**	**925.9**	*1035.9*	*913.2*	*930.5*	*931.4*	*1061.4*	*931.9*	**3691.1**	*3785.0*	*3855.2*
Net Imports [e]	**2.5**	**7.3**	**12.4**	**8.4**	**9.1**	**8.1**	*9.0*	*7.2*	*6.5*	*8.0*	*10.8*	*7.3*	**30.6**	*33.4*	*32.6*
Total Supply	**881.5**	**898.6**	**1049.6**	**892.0**	**919.1**	**934.0**	*1044.9*	*920.4*	*936.9*	*939.4*	*1072.2*	*939.2*	**3721.7**	*3818.4*	*3887.7*
Losses and Unaccounted for [f]	**53.8**	**76.7**	**63.1**	**59.2**	**60.2**	**72.8**	*66.6*	*64.0*	*54.5*	*80.5*	*66.7*	*65.2*	**252.8**	*263.5*	*267.0*
Demand															
Electric Utility Sales															
Residential	**287.7**	**251.0**	**350.9**	**256.1**	**292.5**	**264.2**	*337.8*	*267.8*	*305.9*	*266.4*	*349.5*	*273.3*	**1145.7**	*1162.3*	*1195.0*
Commercial	**227.8**	**238.6**	**279.6**	**236.8**	**236.2**	**254.3**	*282.5*	*245.9*	*245.4*	*250.1*	*289.8*	*250.3*	**982.9**	*1018.8*	*1035.6*
Industrial	**252.1**	**267.7**	**277.6**	**265.7**	**260.0**	**268.5**	*278.5*	*267.9*	*260.0*	*271.9*	*283.1*	*272.9*	**1063.3**	*1074.9*	*1087.9*
Other	**24.7**	**25.3**	**28.4**	**25.7**	**26.4**	**27.4**	*29.6*	*26.8*	*26.6*	*27.0*	*30.2*	*27.3*	**104.2**	*110.3*	*111.1*
Subtotal	**792.4**	**782.6**	**936.6**	**784.4**	**815.1**	**814.3**	*928.4*	*808.4*	*838.0*	*815.4*	*952.5*	*823.7*	**3296.0**	*3366.2*	*3429.6*
Nonutility Use/Sales [b]	**35.3**	**39.3**	**49.8**	**48.4**	**43.8**	**46.9**	*49.9*	*48.0*	*44.4*	*43.5*	*53.0*	*50.3*	**172.8**	*188.7*	*191.2*
Total Demand	**827.7**	**821.9**	**986.5**	**832.8**	**858.9**	**861.2**	*978.3*	*856.4*	*882.4*	*858.9*	*1005.4*	*874.0*	**3468.9**	*3554.9*	*3620.7*
Memo:															
Nonutility Sales to Electric Utilities [b]	**70.4**	**78.3**	**99.4**	**96.5**	**122.8**	**131.4**	*139.8*	*134.5*	*126.7*	*124.0*	*151.0*	*143.4*	**344.5**	*528.4*	*545.2*

[a] "Other" includes generation from wind, wood, waste, and solar sources.

[b] Electricity(net Generation) from nonutility sources, including cogenerators and small power producers.

[c] Includes refinery still gas and other process or waste gases and liquefied petroleum gases.

[d] Includes geothermal, solar, wind, wood, waste, hydrogen, sulfur, batteries, chemicals and spent sulfite liquor.

[e] Data for 1999 are estimates.

[f] Balancing item, mainly transmission and distribution losses.

[g] Defined as the difference between total nonutility electricity generation and sales to electric utilities by nonutility generators, reported on Form EIA-867, "Annual Nonutility Power Producer Report." Data for 1999 are estimates.

Notes: Minor discrepancies with other EIA published historical data are due to rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following report: *Electric Power Monthly*, DOE/EIA-0226. Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Coal, Nuclear, Electric and Alternate Fuels.

Table 11. U.S. Renewable Energy Use by Sector: Mid World Oil Price Case
(Quadrillion Btu)

	Year				Annual Percentage Change		
	1998	1999	2000	2001	1998-1999	1999-2000	2000-2001
Electric Utilities							
Hydroelectric Power [a]	**3.189**	**3.079**	*2.765*	*2.811*	**-3.4**	*-10.2*	*1.7*
Geothermal, Solar and Wind Energy [b]	**0.109**	**0.036**	*0.004*	*0.004*	**-67.0**	*-88.9*	*0.0*
Biofuels [c]	**0.021**	**0.021**	*0.021*	*0.021*	**0.0**	*0.0*	*0.0*
Total	**3.319**	**3.136**	*2.790*	*2.835*	**-5.5**	*-11.0*	*1.6*
Nonutility Power Generators							
Hydroelectric Power [a]	**0.149**	**0.140**	*0.154*	*0.121*	**-6.0**	*10.0*	*-21.4*
Geothermal, Solar and Wind Energy [b]	**0.240**	**0.313**	*0.401*	*0.438*	**30.4**	*28.1*	*9.2*
Biofuels [c]	**0.523**	**0.705**	*0.726*	*0.703*	**34.8**	*3.0*	*-3.2*
Total	**0.912**	**1.157**	*1.280*	*1.261*	**26.9**	*10.6*	*-1.5*
Total Power Generation	**4.231**	**4.293**	*4.070*	*4.096*	**1.5**	*-5.2*	*0.6*
Other Sectors [d]							
Residential and Commercial [e]	**0.568**	**0.574**	*0.583*	*0.583*	**1.1**	*1.6*	*0.0*
Industrial [f]	**1.515**	**1.542**	*1.569*	*1.569*	**1.8**	*1.8*	*0.0*
Transportation [g]	**0.095**	**0.100**	*0.105*	*0.106*	**5.3**	*5.0*	*1.0*
Total	**2.178**	**2.216**	*2.258*	*2.258*	**1.7**	*1.9*	*0.0*
Net Imported Electricity [h]	**0.214**	**0.249**	*0.272*	*0.265*	**16.4**	*9.2*	*-2.6*
Total Renewable Energy Demand	**6.623**	**6.757**	*6.600*	*6.619*	**2.0**	*-2.3*	*0.3*

[a] Conventional hydroelectric power only. Hydroelectricity generated by pumped storage is not included in renewable energy.

[b] Also includes photovoltaic and solar thermal energy. Sharp declines since 1998 in the electric utility sector and corresponding increases in the nonutility sector for this category mostly reflect sale of geothermal facilities to the nonutility sector.

[c] Biofuels are fuelwood, wood byproducts, waste wood, municipal solid waste, manufacturing process waste, and alcohol fuels.

[d] Renewable energy includes minor components of non-marketed renewable energy, which is renewable energy that is neither bought nor sold, either directly or indirectly as inputs to marketed energy. The Energy Information Administration does not estimate or project total consumption of non-marketed renewable energy.

[e] Includes biofuels and solar energy consumed in the residential and commercial sectors.

[f] onsists primarily of biofuels for use other than in electricity cogeneration.

[g] Ethanol blended into gasoline.

[h] Represents 78.6 percent of total electricity net imports, which is the proportion of total 1994 net imported electricity (0.459 quadrillion Btu) attributable to renewable sources (0.361 quadrillion Btu).

Notes: Minor discrepancies with other published EIA historical data are due to independent rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Table A1. Annual U.S. Energy Supply and Demand

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Real Gross Domestic Product (GDP)															
(billion chained 1996 dollars)	**6113**	**6368**	**6592**	**6708**	**6676**	**6880**	**7063**	**7348**	**7544**	**7813**	**8159**	**8516**	**8876**	*9341*	*9696*
Imported Crude Oil Price [a]															
(nominal dollars per barrel)	**18.13**	**14.57**	**18.08**	**21.75**	**18.70**	**18.20**	**16.14**	**15.52**	**17.14**	**20.61**	**18.50**	**12.08**	**17.21**	*27.86*	*24.58*
Petroleum Supply															
Crude Oil Production [b]															
(million barrels per day)	**8.35**	**8.14**	**7.61**	**7.36**	**7.42**	**7.17**	**6.85**	**6.66**	**6.56**	**6.46**	**6.45**	**6.25**	**5.88**	*5.84*	*5.91*
Total Petroleum Net Imports (including SPR)															
(million barrels per day)	**5.91**	**6.59**	**7.20**	**7.16**	**6.63**	**6.94**	**7.62**	**8.05**	**7.89**	**8.50**	**9.16**	**9.76**	**9.91**	*10.12*	*10.75*
Energy Demand															
World Petroleum															
(million barrels per day)	**63.1**	**64.9**	**65.9**	**66.0**	**66.6**	**66.8**	**67.0**	**68.3**	**69.9**	**71.4**	**73.1**	**73.6**	**74.8**	*75.9*	*77.9*
U.S. Petroleum															
(million barrels per day)	**16.72**	**17.34**	**17.37**	**17.04**	**16.77**	**17.10**	**17.24**	**17.72**	**17.72**	**18.31**	**18.62**	**18.92**	**19.52**	*19.58*	*20.00*
Natural Gas															
(trillion cubic feet)	**17.21**	**18.03**	**18.80**	**18.72**	**19.03**	**19.54**	**20.28**	**20.71**	**21.58**	**21.96**	**21.95**	**21.26**	**21.36**	*22.22*	*22.82*
Coal															
(million short tons)	**830**	**877**	**891**	**897**	**898**	**907**	**943**	**950**	**962**	**1006**	**1029**	**1039**	**1039**	*1065*	*1090*
Electricity (billion kilowatthours)															
Utility Sales [c]	**2457**	**2578**	**2647**	**2713**	**2762**	**2763**	**2861**	**2935**	**3013**	**3098**	**3140**	**3240**	**3296**	*3366*	*3430*
Nonutility Own Use [d]	**NA**	**NA**	**91**	**113**	**119**	**122**	**127**	**138**	**145**	**145**	**148**	**156**	**173**	*189*	*191*
Total	**NA**	**NA**	**2738**	**2826**	**2881**	**2885**	**2988**	**3073**	**3159**	**3243**	**3288**	**3396**	**3469**	*3555*	*3621*
Total Energy Demand [e]															
(quadrillion Btu)	**NA**	**NA**	**84.2**	**84.2**	**84.5**	**85.6**	**87.4**	**89.2**	**90.9**	**93.9**	**94.2**	**94.4**	**96.3**	*97.8*	*99.6*
Total Energy Demand per Dollar of GDP															
(thousand Btu per 1996 Dollar)	**NA**	**NA**	**12.77**	**12.55**	**12.66**	**12.44**	**12.37**	**12.14**	**12.07**	**12.02**	**11.54**	**11.09**	**10.85**	*10.47*	*10.27*

[a] Refers to the imported cost of crude oil to U.S. refiners.

[b] Includes lease condensate.

[c] Total annual electric utility sales for historical periods are derived from the sum of monthly sales figures based on submissions by electric utilities of Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions." These historical values differ from annual sales totals based on *Form EIA-861*, reported in several EIA publications, but match alternate annual totals reported in EIA's *Electric Power Monthly*, DOE/EIA-0226.

[d] Defined as the difference between total nonutility electricity generation and sales to electric utilities by nonutility generators, reported on Form EIA-867, "Annual Nonutility Power Producer Report." Data for 1999 are estimates.

[e] "Total Energy Demand" refers to the aggregate energy concept presented in Energy Information Administration, *Annual Energy Review*, 1997, DOE/EIA-0384(97) (AER), Table 1.1. Prior to 1990, some components of renewable energy consumption, particularly relating to consumption at nonutility electric generating facilities, were not available. For those years, a less compehensive measure of total energy demand can be found in EIA's *AER*. The conversion from physical units to Btu is calculated using a subset of conversion factors used in the calculations performed for gross energy consumption in Energy Information Administration, *Monthly Energy Review (MER*). Consequently, the historical data may not precisely match those published in the *MER* or the *AER*.

Notes: SPR: Strategic Petroleum Reserve. Minor discrepancies with other published EIA historical data are due to independent rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Latest data available from Bureau of Economic Analysis; Energy Information Administration; latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109; *Petroleum Supply Annual*, DOE/EIA-0340/2; *Natural Gas Monthly*, DOE/EIA-0130*; Electric Power Monthly*, DOE/EIA-0226; *Quarterly Coal Report*, DOE/EIA-0121; *International Petroleum Statistics Report* DOE/EIA-520, and Weekly Petroleum *Status Report* DOE/EIA-0208. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0900.

Table A2. Annual U.S. Macroeconomic and Weather Indicators

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Macroeconomic															
Real Gross Domestic Product (billion chained 1996 dollars)	6113	6368	6592	6708	6676	6880	7063	7348	7544	7813	8159	8516	8876	*9341*	*9696*
GDP Implicit Price Deflator (Index, 1996=1.000)	0.776	0.802	0.833	0.865	0.897	0.919	0.941	0.960	0.981	1.000	1.020	1.032	1.048	*1.071*	*1.094*
Real Disposable Personal Income (billion chained 1996 Dollars)	4582	4784	4907	5014	5033	5189	5261	5397	5539	5678	5854	6134	6331	*6524*	*6830*
Manufacturing Production (Index, 1996=1.000)	0.765	0.801	0.816	0.812	0.793	0.825	0.855	0.907	0.955	1.000	1.070	1.123	1.170	*1.245*	*1.301*
Real Fixed Investment (billion chained 1996 dollars)	856	887	911	895	833	886	958	1046	1109	1213	1329	1485	1621	*1797*	*1919*
Real Exchange Rate (Index, 1996=1.000)	NA	NA	NA	0.963	0.966	0.960	1.001	0.981	0.927	1.000	1.102	1.137	1.138	*1.244*	*1.202*
Business Inventory Change (billion chained 1996 dollars)	8.5	17.0	14.2	8.9	-6.8	-4.7	3.6	12.1	14.1	10.1	15.2	25.6	0.1	*8.8*	*6.4*
Producer Price Index (index, 1982=1.000)	1.028	1.069	1.122	1.163	1.165	1.172	1.189	1.205	1.247	1.277	1.275	1.244	1.255	*1.334*	*1.355*
Consumer Price Index (index, 1982-1984=1.000)	1.137	1.184	1.240	1.308	1.363	1.404	1.446	1.483	1.525	1.570	1.606	1.631	1.667	*1.722*	*1.757*
Petroleum Product Price Index (index, 1982=1.000)	0.568	0.539	0.612	0.748	0.671	0.647	0.620	0.591	0.608	0.701	0.680	0.513	0.609	*0.895*	*0.813*
Non-Farm Employment (millions)	102.0	105.2	107.9	109.4	108.3	108.6	110.7	114.1	117.2	119.6	122.7	125.8	128.8	*131.4*	*132.9*
Commercial Employment (millions)	65.2	67.8	70.0	71.3	70.8	71.2	73.2	76.1	78.8	81.1	83.9	86.6	89.5	*91.9*	*93.7*
Total Industrial Production (index, 1996=1.000)	0.780	0.815	0.830	0.828	0.812	0.837	0.866	0.914	0.958	1.000	1.063	1.108	1.147	*1.215*	*1.265*
Housing Stock (millions)	99.8	101.6	102.9	103.5	104.5	105.5	106.8	108.2	109.6	111.0	112.5	114.3	115.8	*116.6*	*117.3*
Weather [a]															
Heating Degree-Days															
U.S.	4334	4653	4726	4016	4200	4441	4700	4483	4531	4713	4542	3951	4169	*4225*	*4463*
New England	6546	6715	6887	5848	5960	6844	6728	6672	6559	6679	6662	5680	5952	*6379*	*6467*
Middle Atlantic	5699	6088	6134	4998	5177	5964	5948	5934	5831	5986	5809	4812	5351	*5520*	*5703*
U.S. Gas-Weighted	4391	4804	4856	4139	4337	4458	4754	4659	4707	4980	4802	4183	4399	*4435*	*4714*
Cooling Degree-Days (U.S.)	1269	1283	1156	1260	1331	1040	1218	1220	1293	1180	1156	1410	1297	*1252*	*1235*

[a] Population-weighted degree-days. A degree-day indicates the temperature variation from 65 degrees Fahrenheit (calculated as the simple average of the daily minimum and maximum temperatures) weighted by 1990 population.

Notes: Historical data are printed in bold; forecasts are in italics.

Sources: Historical data: latest data available from: U.S. Department of Commerce, Bureau of Economic Analysis; U.S. Department of Commerce, National Oceanic and Atmospheric Administration; Federal Reserve System, *Statistical Release* G.17(419); U.S. Department of Transportation; American Iron and Steel Institute. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0900.

Table A3. Annual International Petroleum Supply and Demand Balance

(Millions Barrels per Day, Except OECD Commercial Stocks)

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Demand [a]															
OECD															
U.S. (50 States)	16.7	17.3	17.4	17.0	16.8	17.1	17.2	17.7	17.7	18.3	18.6	18.9	19.5	19.6	20.0
Europe [b]	12.3	12.4	12.5	12.6	13.4	13.6	13.5	13.6	14.1	14.3	14.4	14.7	14.5	14.5	14.6
Japan	4.5	4.8	5.0	5.1	5.3	5.4	5.4	5.7	5.7	5.9	5.7	5.5	5.6	5.5	5.6
Other OECD	2.5	2.6	2.7	2.7	2.7	2.7	2.8	2.9	3.0	3.0	3.1	3.1	3.2	3.3	3.4
Total OECD	36.0	37.1	37.6	37.5	38.1	38.8	39.0	39.9	40.6	41.4	41.8	42.3	42.8	42.9	43.6
Non-OECD															
Former Soviet Union	9.0	8.9	8.7	8.4	8.3	6.8	5.6	4.8	4.6	4.0	3.9	3.8	3.6	3.7	3.7
Europe	2.2	2.2	2.1	1.9	1.4	1.3	1.3	1.3	1.3	1.4	1.5	1.5	1.6	1.6	1.7
China	2.1	2.3	2.4	2.3	2.5	2.7	3.0	3.2	3.4	3.6	3.9	4.1	4.3	4.5	4.8
Other Asia	4.1	4.4	4.9	5.3	5.7	6.2	6.8	7.3	7.9	8.5	9.0	8.7	8.8	9.2	9.7
Other Non-OECD	9.7	10.0	10.3	10.5	10.6	11.0	11.4	11.8	12.1	12.4	13.0	13.3	13.6	14.0	14.4
Total Non-OECD	27.1	27.7	28.3	28.5	28.5	28.0	28.0	28.4	29.3	30.0	31.3	31.3	31.9	33.0	34.2
Total World Demand	63.1	64.9	66.0	66.0	66.6	66.8	67.0	68.3	69.9	71.4	73.1	73.6	74.8	75.9	77.9
Supply [c]															
OECD															
U.S. (50 States)	10.7	10.5	9.9	9.7	9.9	9.8	9.6	9.4	9.4	9.4	9.5	9.3	9.0	9.1	9.2
Canada	2.0	2.0	2.0	2.0	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.7	2.6	2.7	2.7
North Sea [d]	3.8	3.8	3.7	3.9	4.1	4.5	4.8	5.5	5.9	6.3	6.2	6.2	6.3	6.5	6.4
Other OECD	1.4	1.5	1.4	1.5	1.5	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.5	1.7	1.8
Total OECD	17.9	17.8	17.1	17.1	17.5	17.9	18.0	18.7	19.2	19.7	19.9	19.7	19.4	20.0	20.1
Non-OECD															
OPEC	19.6	21.5	23.3	24.5	24.6	25.8	26.6	27.0	27.6	28.3	29.9	30.4	29.3	31.1	32.1
Former Soviet Union	12.5	12.5	12.1	11.4	10.4	8.9	8.0	7.3	7.1	7.1	7.1	7.2	7.4	7.8	8.1
China	2.7	2.7	2.8	2.8	2.8	2.8	2.9	2.9	3.0	3.1	3.2	3.2	3.2	3.3	3.3
Mexico	2.9	2.9	2.9	3.0	3.2	3.2	3.2	3.2	3.1	3.3	3.4	3.5	3.4	3.5	3.6
Other Non-OECD	6.9	11.7	7.7	8.0	8.1	8.4	8.7	9.2	9.9	10.2	10.5	10.8	11.2	11.3	11.5
Total Non-OECD	44.6	47.0	48.9	49.7	49.1	49.1	49.4	49.6	50.7	52.0	54.2	55.2	54.5	56.9	58.5
Total World Supply	62.5	64.8	65.9	66.8	66.7	67.0	67.4	68.3	69.9	71.8	74.1	74.9	73.9	76.9	78.5
Total Stock Withdrawals	0.6	0.1	0.0	-0.8	-0.1	-0.2	-0.4	0.0	0.0	-0.4	-1.0	-1.3	0.8	-1.0	-0.7
OECD Comm. Stocks, End (bill. bbls.)	2.7	2.6	2.6	2.7	2.7	2.7	2.8	2.8	2.7	2.7	2.7	2.8	2.6	2.8	2.8
Net Exports from Former Soviet Union	3.5	3.6	3.4	3.0	2.1	2.1	2.3	2.4	2.6	3.0	3.3	3.5	3.8	4.1	4.4

[a] Demand for petroleum by the OECD countries is synonymous with "petroleum product supplied," which is defined in the glossary of the EIA *Petroleum Supply Monthly*, DOE/EIA-0109. Demand for petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel and loss, and bunkering.

[b] OECD Europe includes the former East Germany.

[c] Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources.

[d] Includes offshore supply from Denmark, Germany, the Netherlands, Norway, and the United Kingdom.

OECD: Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States. The Czech Republic, Hungary, Mexico, Poland, and South Korea are all members of OECD, but are not yet included in our OECD estimates.

OPEC: Organization of Petroleum Exporting Countries: Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

SPR: Strategic Petroleum Reserve

Former Soviet Union: Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Notes: Minor discrepancies with other published EIA historical data are due to rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Energy Information Administration: latest data available from EIA databases supporting the following reports: *International Petroleum Statistics Report*, DOE/EIA-0520, and Organization for Economic Cooperation and Development, Annual and Monthly Oil Statistics Database.

Table A4. Annual Average U. S. Energy Prices
(Nominal Dollars)

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Imported Crude Oil Prices															
Imported Average[a]	18.13	14.57	18.08	21.75	18.70	18.20	16.14	15.52	17.14	20.61	18.50	12.08	17.21	*27.86*	*24.58*
WTI[b] Spot Average	19.20	15.98	19.78	24.48	21.60	20.54	18.49	17.16	18.41	22.11	20.61	14.45	19.25	*29.89*	*26.61*
Natural Gas Wellhead															
(dollars per thousand cubic feet)	1.66	1.69	1.69	1.71	1.64	1.74	2.04	1.85	1.55	2.17	2.32	1.95	2.08	*3.37*	*3.75*
Petroleum Products															
Gasoline Retail [b] (dollars per gallon)															
All Grades	0.91	0.92	1.02	1.17	1.15	1.14	1.13	1.13	1.16	1.25	1.24	1.07	1.18	*1.52*	*1.43*
Regular Unleaded	0.91	0.91	0.99	1.13	1.10	1.09	1.07	1.08	1.11	1.20	1.20	1.03	1.14	*1.48*	*1.40*
No. 2 Diesel Oil, Retail															
(dollars per gallon)	0.93	0.91	0.99	1.16	1.12	1.10	1.11	1.11	1.10	1.22	1.19	1.04	1.12	*1.48*	*1.39*
No. 2 Heating Oil, Wholesale															
(dollars per gallon)	0.53	0.47	0.56	0.70	0.62	0.58	0.54	0.51	0.51	0.64	0.59	0.42	0.51	*0.87*	*0.76*
No. 2 Heating Oil, Retail															
(dollars per gallon)	0.80	0.81	0.90	1.06	1.02	0.93	0.91	0.88	0.87	0.99	0.99	0.85	0.88	*1.31*	*1.23*
No. 6 Residual Fuel Oil, Retail [c]															
(dollars per barrel)	17.76	14.04	16.20	18.66	14.32	14.21	14.00	14.79	16.49	19.01	17.82	12.83	15.92	*25.60*	*23.13*
Electric Utility Fuels															
Coal															
(dollars per million Btu)	1.51	1.47	1.44	1.45	1.45	1.41	1.38	1.36	1.32	1.29	1.27	1.25	1.22	*1.20*	*1.20*
Heavy Fuel Oil [d]															
(dollars per million Btu)	2.98	2.41	2.85	3.22	2.49	2.46	2.36	2.40	2.60	3.01	2.79	2.07	2.39	*4.22*	*3.72*
Natural Gas															
(dollars per million Btu)	2.24	2.26	2.36	2.32	2.15	2.33	2.56	2.23	1.98	2.64	2.76	2.38	2.57	*4.00*	*4.25*
Other Residential															
Natural Gas															
(dollars per thousand cubic feet)	5.55	5.47	5.64	5.80	5.82	5.89	6.17	6.41	6.06	6.35	6.95	6.83	6.63	*7.57*	*8.63*
Electricity															
(cents per kilowatthour)	7.4	7.5	7.6	7.8	8.1	8.2	8.3	8.4	8.4	8.4	8.4	8.3	8.1	*8.3*	*8.3*

[a]Refiner acquisition cost (RAC) of imported crude oil.
[b]West Texas Intermediate.
[c]Average self-service cash prices.
[d]Average for all sulfur contents.
[e]Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Marketing Monthly*, DOE/EIA-0380; *Natural Gas Monthly*, DOE/EIA-0130; *Monthly Energy Review*, DOE/EIA-0035; *Electric Power Monthly*, DOE/EIA-0226.

Table A5. Annual U.S. Petroleum Supply and Demand

(Million Barrels per Day, Except Closing Stocks)

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Supply															
Crude Oil Supply															
Domestic Production [a]	8.35	8.14	7.61	7.36	7.42	7.17	6.85	6.66	6.56	6.46	6.45	6.25	5.88	5.84	5.91
Alaska	1.96	2.02	1.87	1.77	1.80	1.71	1.58	1.56	1.48	1.39	1.30	1.17	1.05	0.96	1.00
Lower 48	6.39	6.12	5.74	5.58	5.62	5.46	5.26	5.10	5.08	5.07	5.16	5.08	4.83	4.88	4.91
Net Imports (including SPR) [b]	4.52	4.95	5.70	5.79	5.67	5.99	6.69	6.96	7.14	7.40	8.12	8.60	8.61	8.87	9.32
Other SPR Supply	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.00	0.00	0.00	0.00	0.02	0.01	0.08	0.08
Stock Draw (Including SPR)	-0.13	0.00	-0.09	0.02	-0.01	0.00	-0.08	-0.02	0.09	0.05	-0.06	-0.07	0.09	-0.03	-0.02
Product Supplied and Losses	-0.03	-0.04	-0.03	-0.02	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	0.00	0.00	0.00	0.00	0.00
Unaccounted-for Crude Oil	0.14	0.20	0.20	0.26	0.20	0.26	0.17	0.27	0.19	0.22	0.14	0.11	0.19	0.36	0.21
Total Crude Oil Supply	12.85	13.25	13.40	13.41	13.30	13.41	13.61	13.87	13.97	14.19	14.66	14.89	14.80	15.12	15.34
Other Supply															
NGL Production	1.59	1.62	1.55	1.56	1.66	1.70	1.74	1.73	1.76	1.83	1.82	1.76	1.85	1.95	1.98
Other Hydrocarbon and Alcohol Inputs	0.12	0.11	0.11	0.13	0.15	0.20	0.25	0.26	0.30	0.31	0.34	0.38	0.38	0.39	0.37
Crude Oil Product Supplied	0.03	0.04	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00
Processing Gain	0.64	0.66	0.66	0.68	0.71	0.77	0.77	0.77	0.77	0.84	0.85	0.89	0.89	0.93	0.91
Net Product Imports [c]	1.39	1.63	1.50	1.38	0.96	0.94	0.93	1.09	0.75	1.10	1.04	1.17	1.30	1.25	1.43
Product Stock Withdrawn	0.09	0.03	0.13	-0.14	-0.04	0.06	-0.05	0.00	0.15	0.03	-0.09	-0.17	0.30	-0.06	-0.03
Total Supply	16.72	17.33	17.37	17.04	16.76	17.10	17.26	17.72	17.72	18.31	18.62	18.92	19.52	19.58	20.00
Demand															
Motor Gasoline [d]	7.19	7.36	7.40	7.31	7.23	7.38	7.48	7.60	7.79	7.89	8.02	8.25	8.43	8.40	8.51
Jet Fuel	1.38	1.45	1.49	1.52	1.47	1.45	1.47	1.53	1.51	1.58	1.60	1.62	1.67	1.71	1.79
Distillate Fuel Oil	2.98	3.12	3.16	3.02	2.92	2.98	3.04	3.16	3.21	3.37	3.44	3.46	3.57	3.67	3.75
Residual Fuel Oil	1.26	1.38	1.37	1.23	1.16	1.09	1.08	1.02	0.85	0.85	0.80	0.89	0.83	0.78	0.80
Other Oils [e]	3.90	4.03	3.95	3.95	3.99	4.20	4.17	4.41	4.36	4.63	4.77	4.69	5.01	5.01	5.15
Total Demand	16.72	17.34	17.37	17.04	16.77	17.10	17.24	17.72	17.72	18.31	18.62	18.92	19.52	19.58	20.00
Total Petroleum Net Imports	5.91	6.59	7.20	7.16	6.63	6.94	7.62	8.05	7.89	8.50	9.16	9.76	9.91	10.12	10.75
Closing Stocks (million barrels)															
Crude Oil (excluding SPR)	349	330	341	323	325	318	335	337	303	284	305	324	284	292	298
Total Motor Gasoline	226	228	213	220	219	216	226	215	202	195	210	216	193	199	204
Jet Fuel	50	44	41	52	49	43	40	47	40	40	44	45	41	41	41
Distillate Fuel Oil	134	124	106	132	144	141	141	145	130	127	138	156	125	127	132
Residual Fuel Oil	47	45	44	49	50	43	44	42	37	46	40	45	36	41	39
Other Oils [f]	260	267	257	261	267	263	273	275	258	250	259	291	246	253	258

[a] Includes lease condensate.
[b] Net imports equals gross imports plus SPR imports minus exports.
[c] Includes finished petroleum products, unfinished oils, gasoline blending components, and natural gas plant liquids for processing.
[d] For years prior to 1993, motor gasoline includes an estimate of fuel ethanol blended into gasoline and certain product reclassifications, not reported elsewhere in EIA. See Appendix B in Energy Information Administration, *Short-Term Energy Outlook*, EIA/DOE-0202(93/3Q), for details on this adjustment.
[e] Includes crude oil product supplied, natural gas liquids, liquefied refinery gas, other liquids, and all finished petroleum products except motor gasoline, jet fuel, distillate, and residual fuel oil.
[f] Includes stocks of all other oils, such as aviation gasoline, kerosene, natural gas liquids (including ethane), aviation gasoline blending components, naphtha and other oils for petrochemical feedstock use, special naphthas, lube oils, wax, coke, asphalt, road oil, and miscellaneous oils.

SPR: Strategic Petroleum Reserve. NGL: Natural Gas Liquids

Notes: Minor discrepancies with other EIA published historical data are due to rounding, with the following exception: recent petroleum demand and supply data displayed here reflect the incorporation of resubmissions of the data as reported in EIA's *Petroleum Supply Monthly*, TableC1. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109, and *Weekly Petroleum Status Report*, DOE/EIA-0208.

Table A6. Annual U.S. Natural Gas Supply and Demand

(Trillion Cubic Feet)

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Supply															
Total Dry Gas Production	**16.62**	**17.10**	**17.31**	**17.81**	**17.70**	**17.84**	**18.10**	**18.82**	**18.60**	**18.85**	**18.90**	**18.71**	**18.66**	*18.70*	*18.94*
Net Imports	**0.94**	**1.22**	**1.27**	**1.45**	**1.64**	**1.92**	**2.21**	**2.46**	**2.69**	**2.78**	**2.84**	**2.99**	**3.38**	*3.46*	*3.88*
Supplemental Gaseous Fuels	**0.10**	**0.10**	**0.11**	**0.12**	**0.11**	**0.12**	**0.12**	**0.11**	**0.11**	**0.11**	**0.10**	**0.10**	**0.10**	*0.11*	*0.12*
Total New Supply	**17.66**	**18.42**	**18.69**	**19.38**	**19.45**	**19.88**	**20.42**	**21.39**	**21.40**	**21.75**	**21.84**	**21.80**	**22.14**	*22.27*	*22.95*
Working Gas in Storage															
Opening	**2.75**	**2.76**	**2.85**	**2.51**	**3.07**	**2.82**	**2.60**	**2.32**	**2.61**	**2.15**	**2.17**	**2.17**	**2.73**	*2.51*	*2.20*
Closing	**2.76**	**2.85**	**2.51**	**3.07**	**2.82**	**2.60**	**2.32**	**2.61**	**2.15**	**2.17**	**2.17**	**2.73**	**2.51**	*2.20*	*2.18*
Net Withdrawals	**-0.01**	**-0.09**	**0.34**	**-0.56**	**0.24**	**0.23**	**0.28**	**-0.28**	**0.45**	**-0.02**	**0.00**	**-0.56**	**0.22**	*0.31*	*0.02*
Total Supply	**17.65**	**18.33**	**19.03**	**18.82**	**19.70**	**20.11**	**20.70**	**21.11**	**21.85**	**21.73**	**21.84**	**21.25**	**22.36**	*22.58*	*22.97*
Balancing Item [a]	**-0.44**	**-0.30**	**-0.23**	**-0.11**	**-0.66**	**-0.56**	**-0.42**	**-0.40**	**-0.27**	**0.24**	**0.11**	**0.01**	**-1.00**	*-0.36*	*-0.15*
Total Primary Supply	**17.21**	**18.03**	**18.80**	**18.72**	**19.03**	**19.54**	**20.28**	**20.71**	**21.58**	**21.96**	**21.95**	**21.26**	**21.36**	*22.22*	*22.82*
Demand															
Lease and Plant Fuel	**1.15**	**1.10**	**1.07**	**1.24**	**1.13**	**1.17**	**1.17**	**1.12**	**1.22**	**1.25**	**1.20**	**1.16**	**1.23**	*1.23*	*1.23*
Pipeline Use	**0.52**	**0.61**	**0.63**	**0.66**	**0.60**	**0.59**	**0.62**	**0.69**	**0.70**	**0.71**	**0.75**	**0.64**	**0.64**	*0.66*	*0.65*
Residential	**4.31**	**4.63**	**4.78**	**4.39**	**4.56**	**4.69**	**4.96**	**4.85**	**4.85**	**5.24**	**4.98**	**4.52**	**4.69**	*4.75*	*5.06*
Commercial	**2.43**	**2.67**	**2.72**	**2.62**	**2.73**	**2.80**	**2.86**	**2.90**	**3.03**	**3.16**	**3.21**	**3.00**	**3.06**	*3.17*	*3.35*
Industrial (Incl. Nonutilities)	**5.95**	**6.38**	**6.82**	**7.02**	**7.23**	**7.53**	**7.98**	**8.17**	**8.58**	**8.87**	**8.83**	**8.69**	**8.63**	*9.44*	*9.69*
Electric Utilities	**2.84**	**2.64**	**2.79**	**2.79**	**2.79**	**2.77**	**2.68**	**2.99**	**3.20**	**2.73**	**2.97**	**3.26**	**3.11**	*2.97*	*2.83*
Total Demand	**17.21**	**18.03**	**18.80**	**18.72**	**19.03**	**19.54**	**20.28**	**20.71**	**21.58**	**21.96**	**21.95**	**21.26**	**21.36**	*22.22*	*22.82*

[a] The balancing item represents the difference between the sum of the components of natural gas supply and the sum of components of natural gas demand.

Notes: Minor discrepancies with other EIA published historical data are due to rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Oil and Gas, Reserves and Natural Gas Division.

Table A7. Annual U.S. Coal Supply and Demand

(Million Short Tons)

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Supply															
Production	918.8	950.3	980.7	1029.	996.0	997.5	945.4	1033.5	1033.0	1063.9	1089.9	1117.5	1094.0	*1094.6*	*1117.8*
Appalachia	NA	NA	464.8	489.0	457.8	456.6	409.7	445.4	434.9	451.9	467.8	460.4	423.3	*424.9*	*414.8*
Interior	NA	NA	198.1	205.8	195.4	195.7	167.2	179.9	168.5	172.8	170.9	168.4	162.5	*151.2*	*152.7*
Western	NA	NA	317.9	334.3	342.8	345.3	368.5	408.3	429.6	439.1	451.3	488.8	508.2	*518.5*	*550.2*
Primary Stock Levels [a]															
Opening	32.1	28.3	30.4	29.0	33.4	33.0	34.0	25.3	33.2	34.4	28.6	34.0	36.5	*36.4*	*36.4*
Closing	28.3	30.4	29.0	33.4	33.0	34.0	25.3	33.2	34.4	28.6	34.0	36.5	36.4	*36.4*	*34.6*
Net Withdrawals	3.8	-2.1	1.4	-4.4	0.4	-1.0	8.7	-7.9	-1.2	5.8	-5.3	-2.6	0.2	*S*	*1.7*
Imports	1.7	2.1	2.9	2.7	3.4	3.8	7.3	7.6	7.2	7.1	7.5	8.7	9.1	*11.0*	*11.6*
Exports	79.6	95.0	100.8	105.8	109.0	102.5	74.5	71.4	88.5	90.5	83.5	78.0	58.5	*58.2*	*60.5*
Total Net Domestic Supply	844.7	855.3	884.2	921.6	890.9	897.8	886.9	961.8	950.4	986.3	1008.5	1045.7	1044.8	*1047.5*	*1070.6*
Secondary Stock Levels [b]															
Opening	175.2	185.5	158.4	146.1	168.2	167.7	163.7	120.5	136.1	134.6	123.0	106.4	129.4	*143.5*	*129.1*
Closing	185.5	158.4	146.1	168.2	167.7	163.7	120.5	136.1	134.6	123.0	106.4	129.4	143.5	*129.1*	*121.8*
Net Withdrawals	-10.2	27.0	12.3	-22.1	0.5	4.0	43.2	-15.7	1.5	11.7	16.6	-23.0	-14.1	*14.4*	*7.3*
Waste Coal Supplied to IPPs [c]	0.0	0.0	0.0	0.0	0.0	6.0	6.4	7.9	8.5	8.8	8.1	8.6	9.7	*12.2*	*12.2*
Total Supply	834.4	882.3	896.5	899.4	891.4	907.8	936.5	954.0	960.4	1006.7	1033.2	1031.3	1040.4	*1074.2*	*1090.1*
Demand															
Coke Plants	37.0	41.9	40.5	38.9	33.9	32.4	31.3	31.7	33.0	31.7	30.2	28.2	28.1	*29.0*	*29.1*
Electricity Production															
Electric Utilities	717.9	758.4	766.9	773.5	772.3	779.9	813.5	817.3	829.0	874.7	900.4	910.9	894.1	*864.6*	*885.9*
Nonutilities (Excl. Cogen.) [d]	NA	NA	0.9	1.6	10.2	14.6	17.1	19.5	20.8	22.2	21.6	26.9	45.9	*100.5*	*102.9*
Retail and General Industry	75.2	76.3	82.3	83.1	81.5	80.2	81.1	81.2	78.9	76.9	77.1	73.0	70.3	*71.3*	*72.2*
Total Demand [e]	830.0	876.5	890.6	897.1	897.8	907.0	943.1	949.7	961.7	1005.6	1029.2	1039.0	1038.5	*1065.4*	*1090.1*
Discrepancy [f]	4.4	5.8	5.9	2.4	-6.4	0.8	-6.6	4.3	-1.3	1.2	4.0	-7.7	*1.9*	*8.7*	*0.0*

[a]Primary stocks are held at the mines, preparation plants, and distribution points.

[b]Secondary stocks are held by users. It includes an estimate of stocks held at utility plants sold to nonutility generators.

[c]Estimated independent power producers (IPPs) consumption of waste coal. This item includes waste coal and coal slurry reprocessed into briquettes.

[d]Estimates of coal consumption by IPPs, supplied by the Office of Coal, Nuclear, Electric, and Alternate Fuels, Energy Information Administration (EIA). Quarterly coal consumption estimates for 1999 and projections for 2000 and 2001 are based on (1) estimated consumption by utility power plants sold to nonutility generators during 1999, and (2) annual coal-fired generation at nonutilities from Form EIA-867 (Annual Nonutility Power Producer Report).

[e]Total Demand includes estimated IPP consumption.

[f]The discrepancy reflects an unaccounted-for shipper and receiver reporting difference, assumed to be zero in the forecast period. Prior to 1994, discrepancy may include some waste coal supplied to IPPs that has not been specifically identified.

Notes: Rows and columns may not add due to independent rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Quarterly Coal Report*, DOE/EIA-0121, and *Electric Power Monthly*, DOE/EIA-0226. Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Coal, Nuclear, Electric and Alternate Fuels.

Table A8. Annual U.S. Electricity Supply and Demand

(Billion Kilowatt-hours)

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Supply															
Net Utility Generation															
Coal	1463.8	1540.7	1553.7	1559.6	1551.2	1575.9	1639.2	1635.5	1652.9	1737.5	1787.8	1807.5	1767.7	1713.9	1765.0
Petroleum	118.5	148.9	158.3	117.0	111.5	88.9	99.5	91.0	60.8	67.3	77.8	110.2	86.9	65.1	85.2
Natural Gas	272.6	252.8	266.6	264.1	264.2	263.9	258.9	291.1	307.3	262.7	283.6	309.2	296.4	283.5	269.0
Nuclear	455.3	527.0	529.4	576.9	612.6	618.8	610.3	640.4	673.4	674.7	628.6	673.7	725.0	739.3	729.2
Hydroelectric	249.7	222.9	265.1	279.9	275.5	239.6	265.1	243.7	293.7	328.0	337.2	304.4	293.9	263.9	268.3
Geothermal and Other [a]	12.3	12.0	11.3	10.7	10.1	10.2	9.6	8.9	6.4	7.2	7.5	7.2	3.7	2.3	2.2
Subtotal	2572.1	2704.3	2784.3	2808.2	2825.0	2797.2	2882.5	2910.7	2994.5	3077.4	3122.5	3212.2	3173.7	3067.9	3118.8
Nonutility Generation [b]	0.0	0.0	187.6	216.7	246.3	286.1	314.4	343.1	363.3	369.6	371.7	405.7	517.4	717.0	736.3
Total Generation	2572.1	2704.3	2971.9	3024.9	3071.3	3083.4	3196.9	3253.8	3357.8	3447.0	3494.2	3617.9	3691.1	3785.0	3855.2
Net Imports [c]	46.3	31.8	11.0	2.3	19.6	25.4	27.8	44.8	39.2	38.0	36.6	27.6	30.6	33.4	32.6
Total Supply	2618.5	2736.0	2982.8	3027.2	3091.0	3108.8	3224.7	3298.6	3397.1	3485.0	3530.8	3645.5	3721.7	3818.4	3887.7
Losses and Unaccounted for [d]	NA	NA	243.1	207.3	215.0	223.6	236.3	225.7	238.4	242.3	242.9	249.4	252.8	263.5	267.0
Demand															
Electric Utility Sales															
Residential	850.4	892.9	905.5	924.0	955.4	935.9	994.8	1008.5	1042.5	1082.5	1075.8	1127.7	1145.7	1162.3	1195.0
Commercial	660.4	699.1	725.9	751.0	765.7	761.3	794.6	820.3	862.7	887.4	928.4	968.5	982.9	1018.8	1035.6
Industrial	858.2	896.5	925.7	945.5	946.6	972.7	977.2	1008.0	1012.7	1030.4	1032.7	1040.0	1063.3	1074.9	1087.9
Other	88.2	89.6	89.8	92.0	94.3	93.4	94.9	97.8	95.4	97.5	102.9	103.5	104.2	110.3	111.1
Subtotal	2457.3	2578.1	2646.8	2712.6	2762.0	2763.4	2861.5	2934.6	3013.3	3097.8	3139.8	3239.8	3296.0	3366.2	3429.6
Nonutility Own Use [e]	NA	NA	94.7	101.5	108.0	121.8	126.9	138.4	145.4	144.9	148.2	156.2	172.8	188.7	191.2
Total Demand	NA	NA	2739.7	2819.9	2875.9	2885.1	2988.4	3073.0	3158.7	3242.7	3287.9	3396.0	3468.9	3554.9	3620.7
Memo:															
Nonutility Sales to Electric Utilities	NA	NA	92.9	115.2	138.3	164.4	187.5	204.7	217.9	224.6	223.5	249.5	344.5	528.4	545.2

[a]Other includes generation from wind, wood, waste, and solar sources.

[b]Net generation.

[c]Data for 1999 are estimates.

[d]Balancing item, mainly transmission and distribution losses.

[e]Defined as the difference between total nonutility electricity generation and sales to electric utilities by nonutility generators, reported on Form EIA-867, "Annual Nonutility Power Producer Report." Data for 1999 are estimates.

Notes: Minor discrepancies with other EIA published historical data are due to rounding. Historical data are printed in bold; forecasts are in italics.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following report: *Electric Power Monthly*, DOE/EIA-0226 and Electric Power Annual,DOE/EIA-0348.

Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Coal, Nuclear, Electric and Alternate Fuels.