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Short-Term Energy Outlook

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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 to subscribers in April and October.

The forecast period for this issue of the *Outlook* extends from October 1999 through December 2000. Data values for the third quarter 1999, 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 1999 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.

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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Sharply Higher Fuel Bills Expected This Winter

Consumers can expect to pay much more this winter to heat their homes compared to last year. Much higher oil and gas prices, as well as the likelihood that this winter will be colder than last winter, could boost household heating expenditures by 19 to 44 percent, depending on the type of fuel used. The magnitude of the expected increases largely reflects the extraordinarily low costs enjoyed by consumers last winter.

Crude Oil Prices On The Rise

Crude oil prices have risen from a low monthly average of $9.39 per barrel in December 1998 to $23 per barrel in October 1999. Crude costs are projected to continue to rise through December, peaking at $24.50 per barrel, then ease slightly (by about $2 dollars per barrel) throughout the next year. On average, the crude oil price for the year 2000 is projected be $5.00 per barrel higher than this year's price, leading to higher prices for all petroleum products through the next year.

World Oil Inventories Falling

OPEC's continued strong compliance with earlier production cuts is expected to have a large impact on world oil inventories. Estimates of the amount of excess global oil stocks range between 200 and 400 million barrels. The forecast expects about 350 million barrels to be drawn down by the end of this year, which implies that the global oil stock situation will either be at or below normal levels at that time.

Natural Gas Storage About Equal to Last Year

Assuming normal weather, this winter natural gas wellhead prices are projected to average about 40 percent more than last winter's. Natural gas spot and futures wellhead prices have been quite volatile since August, indicating that some observers are uncertain about the winter supply and storage situation. Our analysis indicates that storage levels in September were about equal to the relatively high levels of one year ago. This, in addition to continued high levels of gas imports, leads to the expectation that wellhead gas prices, while still trending well above last year's levels, may remain below $3 per thousand cubic feet this winter unless very cold weather intervenes.

Electricity Demand Growth Modest in 1999

The outlook for electricity demand in 1999 is modest growth of 1.2 percent. In 2000, electricity demand is expected to grow by 1.8 percent. Heating degree-days this winter are expected to be 8.0 percent higher than those of last winter, which was quite mild. Thus, 3.4 percent higher electricity demand is indicated for this winter compared to demand during last winter.

Table HL1. U. S. Energy Supply and Demand

	Year				Annual Percentage Change		
	1997	1998	1999	2000	1997-1998	1998-1999	1999-2000
Real Gross Domestic Product (GDP)							
(billion chained 1992 dollars)	**7270**	**7552**	*7837*	*8012*	**3.9**	*3.8*	*2.2*
Imported Crude Oil Price [a]							
(nominal dollars per barrel).........................	**18.50**	**12.12**	*17.47*	*22.58*	**-34.5**	*44.1*	*29.3*
Petroleum Supply (million barrels per day)							
Crude Oil Production [b]	**6.45**	**6.25**	*5.99*	*5.97*	**-3.1**	*-4.2*	*-0.3*
Total Petroleum Net Imports							
(including SPR)	**9.16**	**9.76**	*9.83*	*10.15*	**6.6**	*0.7*	*3.3*
Energy Demand							
World Petroleum							
(million barrels per day).............................	**73.0**	**73.8**	*74.9*	*76.2*	**1.1**	*1.5*	*1.7*
Petroleum							
(million barrels per day).............................	**18.62**	**18.92**	*19.29*	*19.32*	**1.6**	*2.0*	*0.2*
Natural Gas							
(trillion cubic feet)	**21.97**	**21.34**	*21.86*	*22.37*	**-2.9**	*2.4*	*2.3*
Coal [c]							
(million short tons)	**1029**	**1044**	*1054*	*1083*	**1.5**	*1.0*	*2.8*
Electricity (billion kilowatthours)							
Utility Sales [d]	**3140**	**3220**	*3259*	*3318*	**2.5**	*1.2*	*1.8*
Nonutility Own Use [e]	**161**	**164**	*166*	*168*	**1.9**	*1.2*	*1.2*
Total	**3301**	**3384**	*3425*	*3487*	**2.5**	*1.2*	*1.8*
Total Energy Demand [f]							
(quadrillion Btu)..	**94.2**	**94.7**	*96.5*	*97.5*	**0.5**	*1.8*	*1.0*
Total Energy Demand per Dollar of GDP							
(thousand Btu per 1992 Dollar)	**12.96**	**12.54**	*12.31*	*12.16*	**-3.2**	*-1.8*	*-1.2*
Renewable Energy as Percent of Total [g] ...	**7.5**	**7.1**	*7.0*	*6.8*			

[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 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, ":Annual Electric Utility Report," reported in several EIA publications, but match alternate annual totals reported in EIA's *Electric Power Monthly*, DOE/EIA-0226.

[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 1998 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 CONTROL0999.

1999-2000 Winter Fuels Outlook

Introduction

This winter--defined as the period from October 1999 to March 2000--is expected to witness both higher space heating fuel demand and prices than those during the previous winter season, during which an economic slide in several emerging markets and a warmer-than-normal winter helped to depress both consumption and prices. Several factors have contributed to the marked oil price increases since the lows of last winter. These are: economic resurgence in areas which had suffered declines, higher-than-expected compliance by OPEC members with new production quotas, and the prospect of a more "normal" winter season bringing colder temperatures than last winter. As a result, consumers are likely to incur higher fuel bills this winter compared to their bills in the previous heating season. Nonetheless, supplies of space-heating fuels are expected to be more than adequate to meet winter demand. The incremental requirements of a severe winter should be met without serious difficulty; but, in that event, consumer prices could be much higher than those of a normal winter season.

Winter Heating Bills

Mainly because of the high likelihood of much higher oil and gas prices this winter, we expect that consumers will face markedly higher expenditures for heating (or other energy uses) over the next two quarters compared to their expenditures during the same period last year. Table WF01 below summarizes our base (normal weather), cold weather and warm weather scenario cases as they apply to typical household winter energy expenditures for key selected heating fuels.

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

	1996-1997	1997-1998	1998-1999	1999-2000 Projections		
	Actual	Actual	Actual	Base	Warm Weather	Cold Weather
Heating Oil (New England)						
Consumption (gals)	676.4	651.0	650.9	688.9	630.9	746.8
Expenditures ($)	710	599	521	748	617	892
Avg. Price ($/gal)	1.05	0.92	0.80	1.09	0.98	1.20
Propane (Midwest)						
Consumption (gals)	898.9	814.4	824.4	887.4	814.8	959.9
Expenditures ($)	998	767	704	957	829	1096
Avg. Price ($/gal)	1.11	0.94	0.85	1.08	1.02	1.14
Natural Gas (Midwest)						
Consumption (mcf)	91.4	82.4	83.5	90.2	82.5	97.9
Expenditures ($)	606	546	524	625	568	687
Avg. Price ($/mcf)	6.63	6.62	6.28	6.93	6.89	7.02

* National average prices.

** Based on typical per-household consumption by region.

Our calculations focus on particular regions of the country with respect to per-household consumption and projected weather factors (i.e., changes in heating degree-days) but utilize the 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.

Expenditures for this winter are likely to be relatively large, especially in comparison to costs seen in the last two winters (1997-1998 and 1998-1999). In our base case projections, we anticipate 44 percent, 36 percent and 19 percent approximate increases in heating fuel bills this winter for households that use primarily heating oil, propane and natural gas, respectively. On the other hand, for all of the fuel types shown, the base case for this winter would not be very different from the experience of the 1996-1997 winter, in terms of fuel demand levels and cost. During that period, winter temperatures were close to normal.

Obviously, the actual outcome this winter will depend very much on the weather. We have considered two cases in addition to the base case (normal weather): 10% colder and 10% warmer-than-normal scenarios (Figure WF1). Cases like these are not particularly likely (the probability of winter weather deviating from normal by at least 10 percent is estimated to be about 5 percent). However, these ranges for weather variation yield realistic upper and lower bounds for energy market behavior over the upcoming heating season.

Upward momentum in world oil prices has been evident in recent months. This is indicative of the pressures engendered by sharply reduced world output and the perception of current and future upward movement in world oil demand, especially as previously hard-hit Asian economies start to recover. Significant demand shifts relative to current expectations could generate particularly sharp reactions in crude oil prices in either direction. Thus, weather variations, to the extent that they are not localized, such as significantly higher-than-normal (or lower-than-normal) heating degree-days across the Northern Hemisphere, would likely result in much higher (lower) world oil prices this winter. We have calculated a plausible range of oil price responses for our weather cases, illustrated in Figure WF1. The implications of these impacts for heating oil are shown in Figure WF2.

For heating oil, aside from net impacts of higher crude costs, refining margins would also increase (decrease) with colder (milder) weather, as marginal distillate supply costs rise (fall) with shifting demand. These estimated effects are included in Figure WF2. High and low ranges for propane have also been calculated.

Figure WF1. Crude Oil Costs to U.S. Refiners: Weather Scenarios

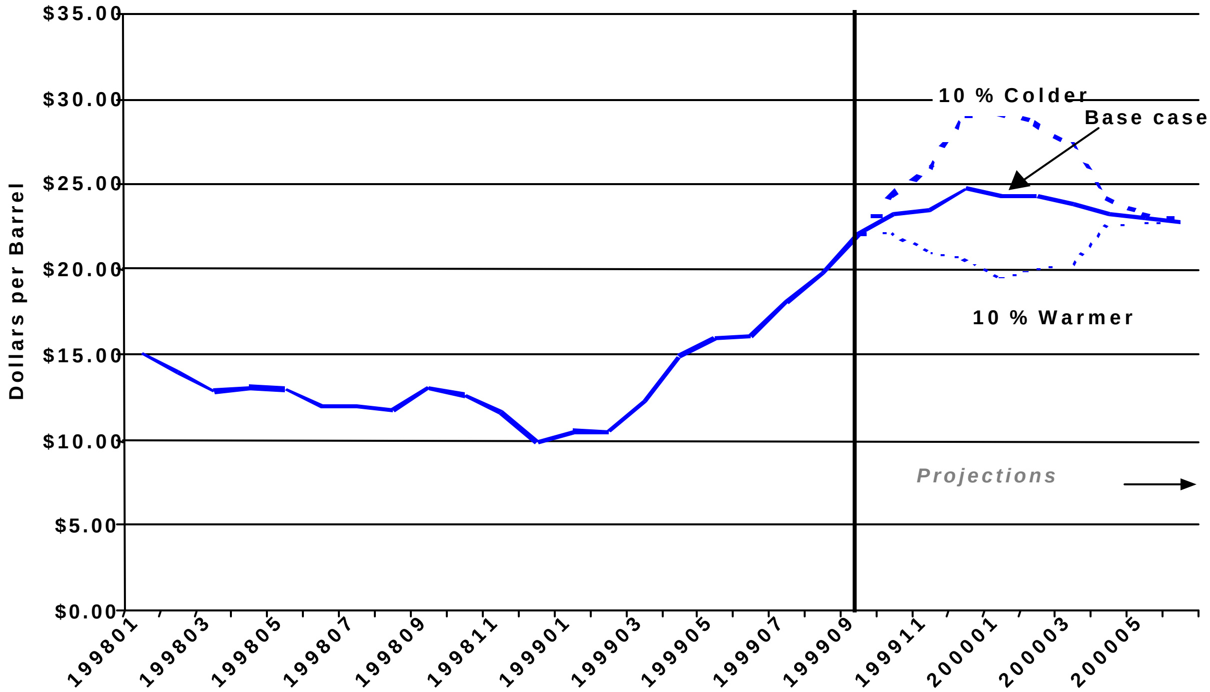
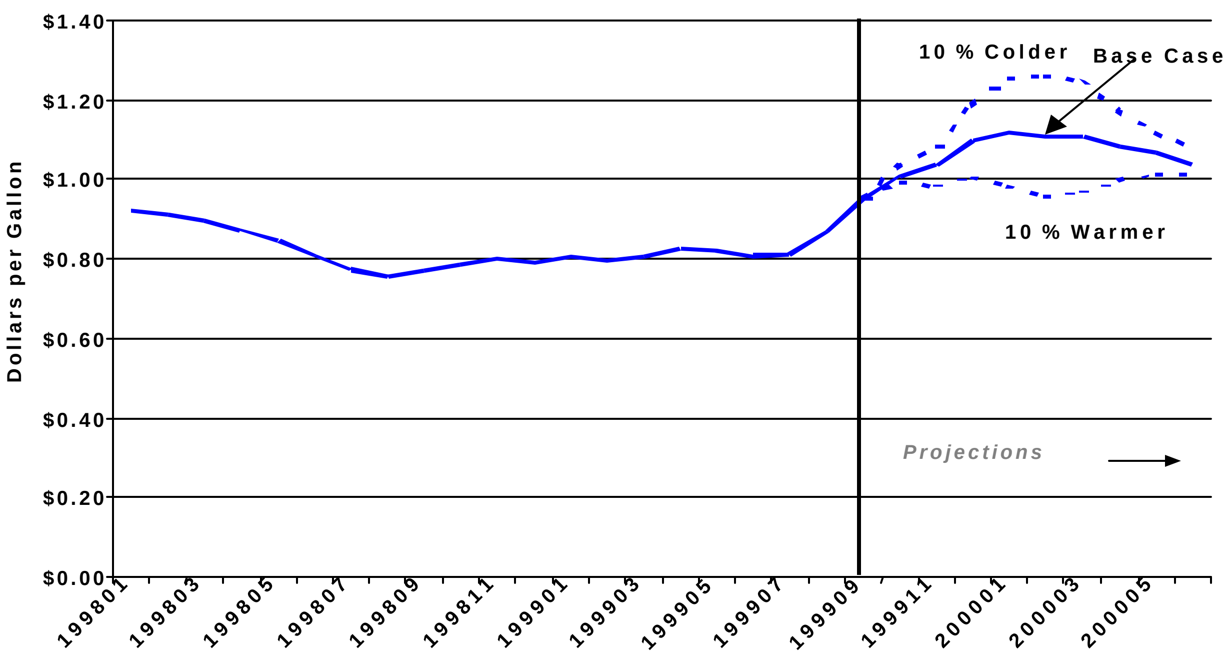
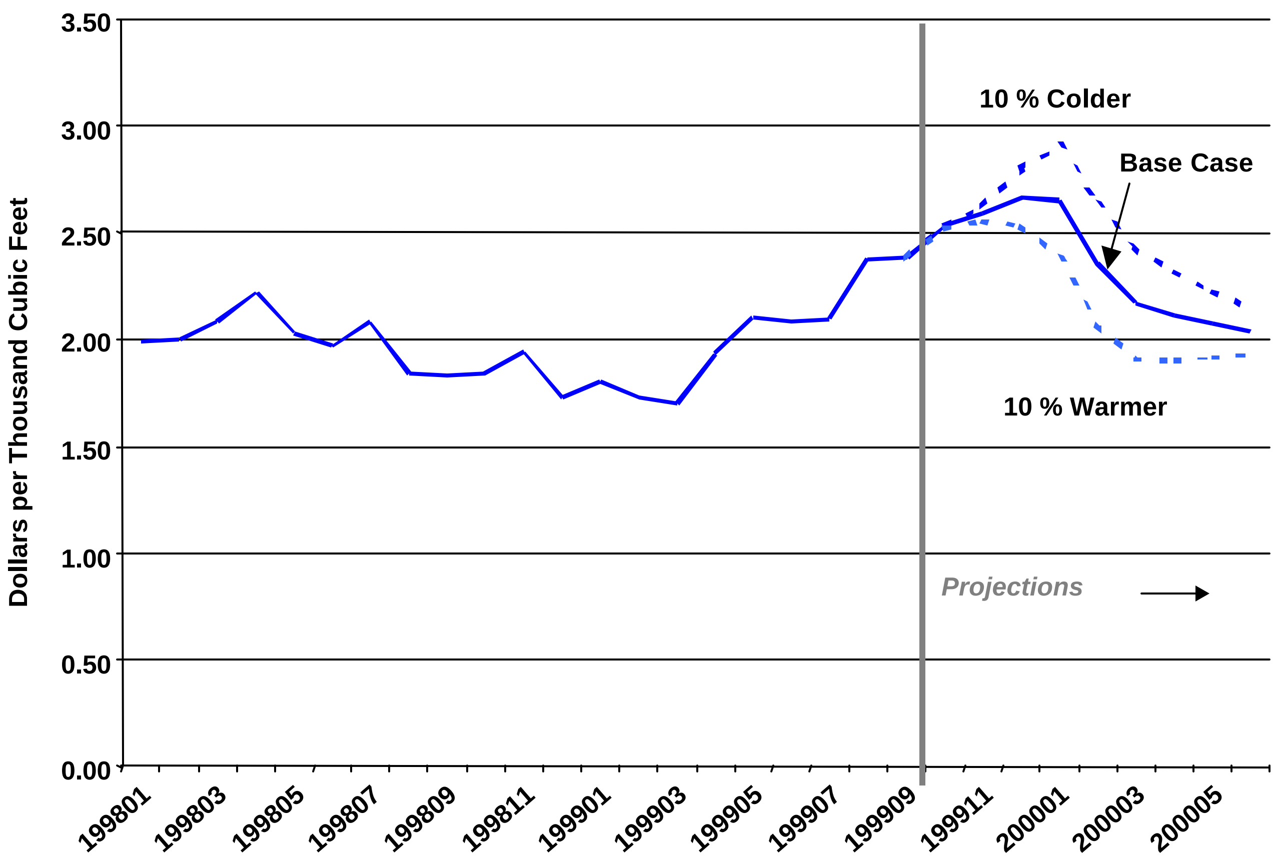


Figure WF2. Residential Heating Oil Prices: Weather Scenarios



Natural gas prices, while they would be expected to rise, are sensitive mostly to shifts in working gas in storage, which are critical for meeting winter demand. Figure WF3 illustrates the expected range for wellhead gas prices this winter under our assumed weather cases. For residential gas customers, increases in wellhead costs are passed on with a lag because of monthly billing cycles and regulatory oversight. The result is a more moderate increase in the typical residential gas bill compared to those of other fuels (Table WF01).

Figure WF3. Natural Gas Wellhead Prices: Weather Scenarios



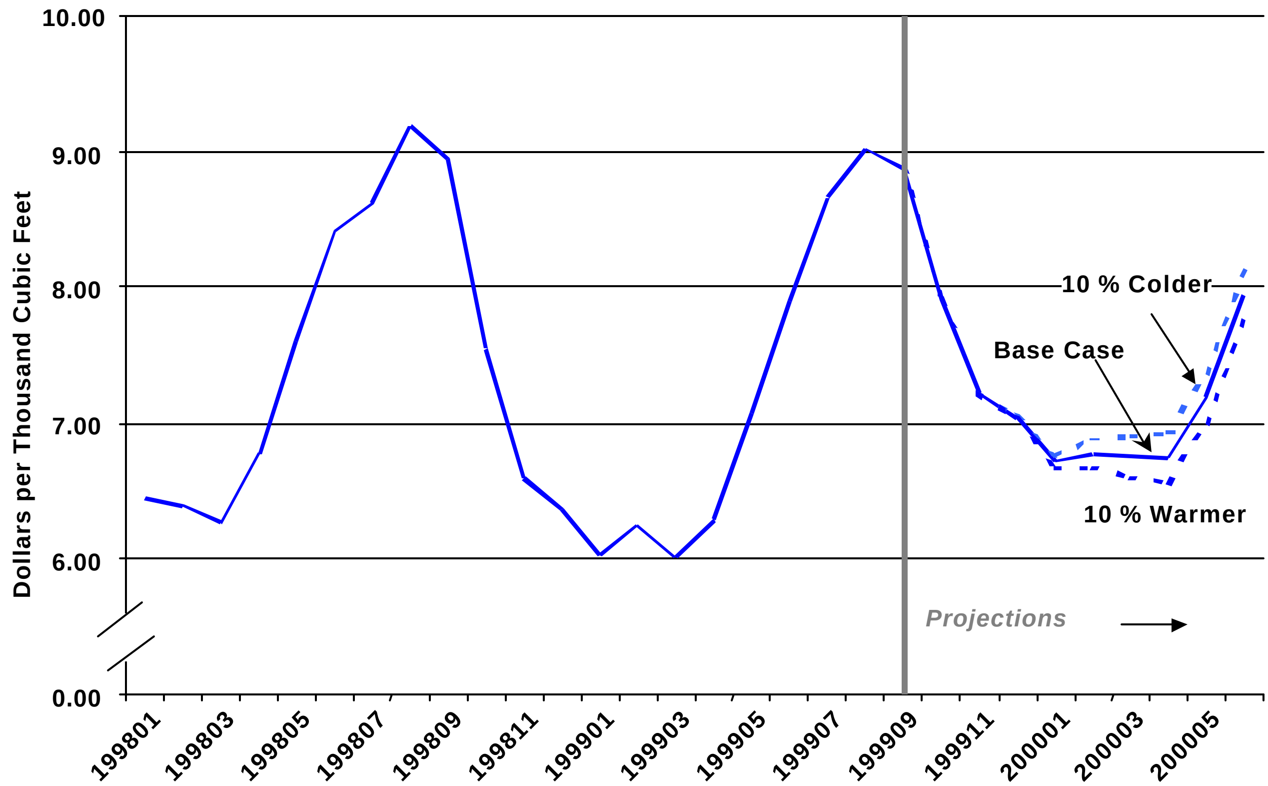
Natural Gas

Demand

A return to normal weather will see demand increase

Total natural gas demand is expected to move higher this winter, averaging 70.4 billion cubic feet (bcf) per day, an increase of 5.9 percent compared to last year's daily average of 66.5 bcf per day. Contributing to the growth in winter demand is the increase in gas space-heating customers (about 1 percent). Most of the increase is related to assumptions of a return to more normal weather patterns. Milder weather last winter resulted in gas-weighted heating degree-days that were 3.5 percent below normal, but several Midwestern areas experienced weather as much as 6.5 percent warmer than normal. As a result, winter consumption in residential and commercial markets is expected to average 20.7 and 12.6 bcf per day, respectively, up about 9 percent and 10 percent from the previous winter's consumption (Figure WF5).

Figure WF4. Residential Natural Gas Prices: Weather Scenarios



Supply

Stock levels are about the same as last year's 5-year high

Domestic gas production is expected to average 51.8 bcf per day during the heating season, up slightly from the 51.2 bcf per day during the previous winter (Figure WF6). Drilling activity for both oil and gas had dropped sharply in the first quarter of 1999 in reaction to the precipitous decline in the price of oil. The total rig count reached a low of 496 in April--44 percent below last April's rig count of 886. Since then, rig counts have recovered with rise in the price of crude oil. By mid-September, the rig count had reached 690, with 561, or 80 percent, of the rigs dedicated to gas exploration. The sharp drop in drilling early in the year and the lead time needed to bring properties to production has been a concern of many in the industry this past spring and summer. However, EIA believes that sufficient production capacity remains to meet the moderate increase in production requirements projected here for the base case and for the severe weather scenario.

Working gas storage at the beginning of the season (October 1) is estimated to have reached 2,955 bcf, about the same as last season's 5-year high of 2,949 bcf but significantly above the October 1, 1998 level of 2,672 bcf (Figure WF7). Storage plays a critical role in meeting increased seasonal demand. In many areas of the country, it is the most important source for local distributing companies to meet peak demand requirements. During this heating season, withdrawals are expected to be significantly higher than last year's to meet the additional demand, averaging 10.7 bcf per day compared to last year's average of 8.4 bcf per day. Due to larger projected withdrawals this winter, end-of-season stocks of working gas are projected to be 1000 bcf. This level is comparable to the 990 bcf seen at the end of the 1996/97 heating season with relatively normal weather, but is much below the 1,430 bcf at the end of the last heating season, March 1999, which was warmer than normal.

Figure WF5. U.S. Winter Natural Gas Demand
(Year-to-Year Percent Change)

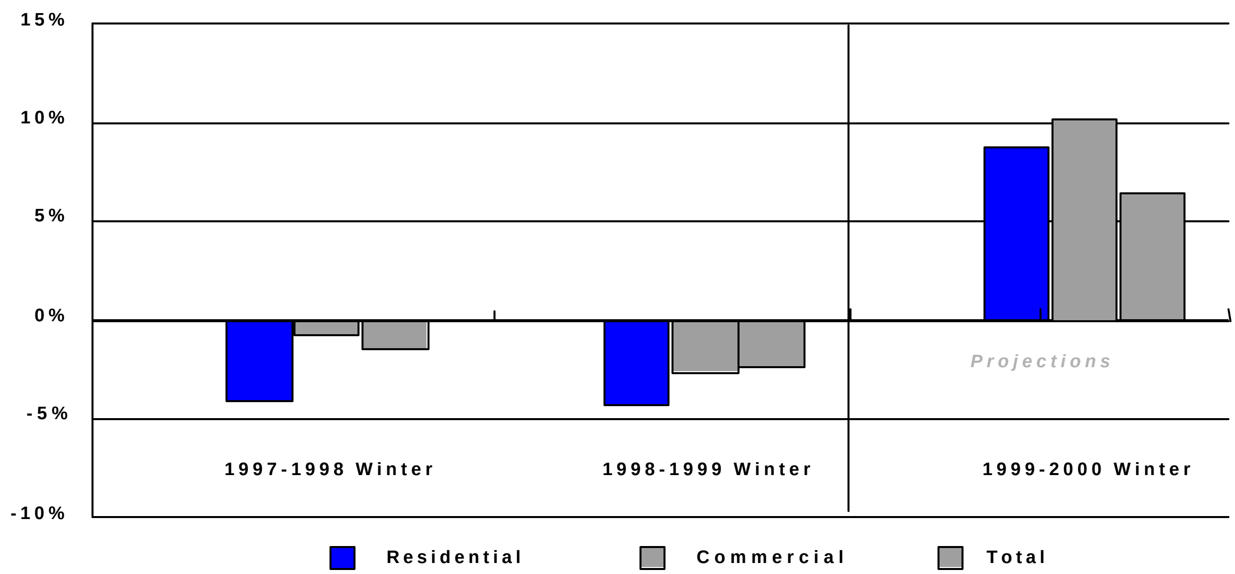


Figure WF6. Components of Natural Gas Supply

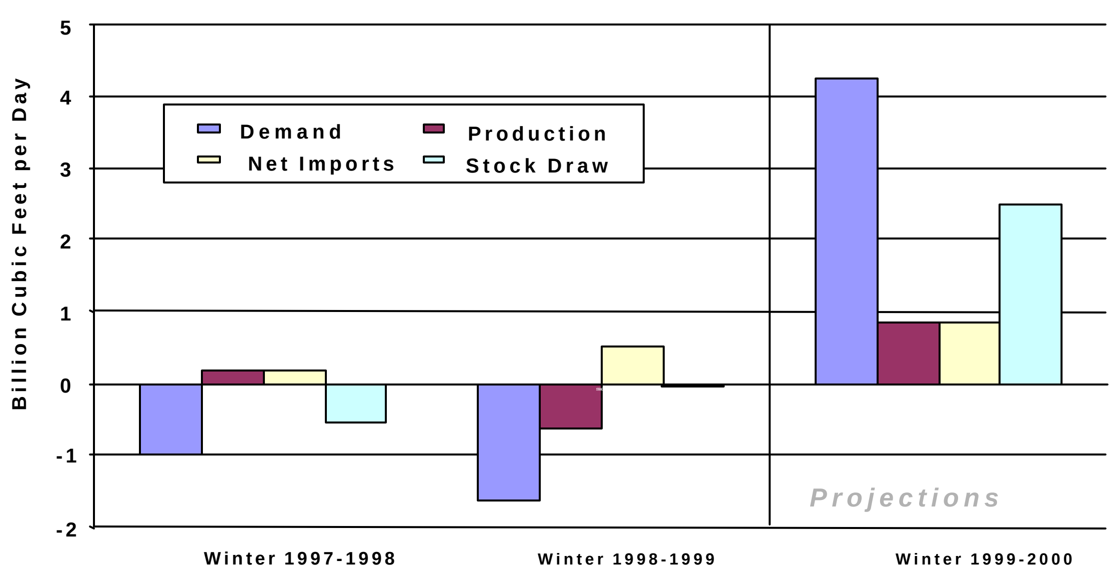
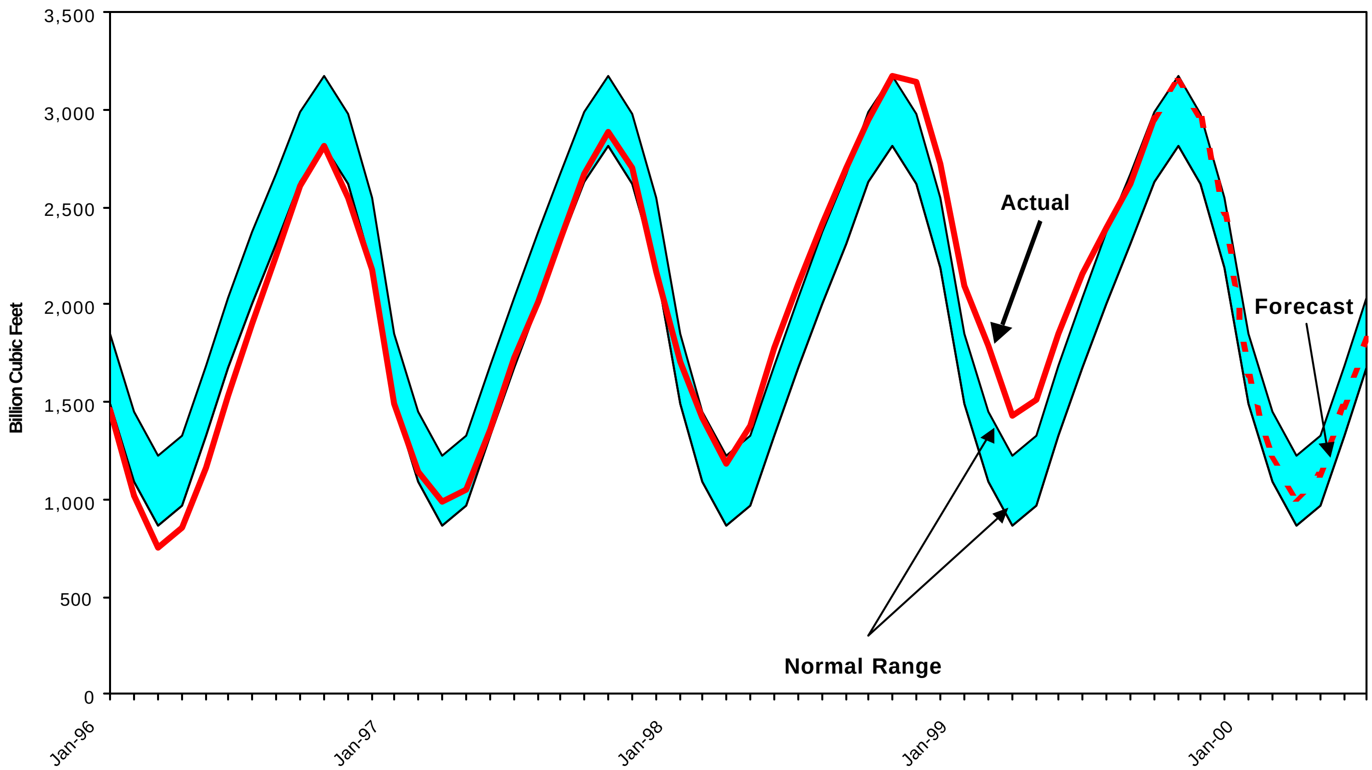


Figure WF7. Working Gas in Storage



Natural gas imports are expected to average 9.6 bcf per day, or 14 percent of demand, compared to last year's 8.7 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, which had remained unchanged for the previous few years, increased late last year as three construction projects were completed, expanding deliverability of Canadian gas by almost 1 bcf per day. The largest of these projects, the expansion of the Northern Border pipeline system, increased import capacity into the Midwest by 700 million cubic feet (mcf) per day.

Price and Expenditures

Higher wellhead prices and normal weather will see residential expenditures rise

Natural gas wellhead prices are projected to average about $2.50 per mcf this winter compared to the $1.79 per mcf average price seen a year ago. Last winter, the average wellhead price was low going into the winter at $1.83, rose slightly to $1.94 by November before sliding to $1.70 by the end of the season. Contributing to the low price of natural gas last season were the mild winter weather in several major gas-consuming markets (such as the Midwest), elevated stock levels, and collapsing oil prices. This year's higher oil prices and expected higher demand have already brought much higher gas prices than last year's (Figure WF4). In late September of this year, prices on the NYMEX futures market for the early months of the upcoming winter season were up 16 to 20 percent from those of last year.

Prices paid by residential consumers are also expected to move up, averaging $6.93 per mcf, up 10 percent from last winter's average of $6.28. At the beginning of this season (September), we estimate that residential prices are about equal to year-ago levels. Consumers could see slightly higher or lower prices during the winter, depending on whether abnormally cold or warm conditions develop.

Other Weather Scenarios

Under a severe weather pattern, in which heating-degree days are 10 percent colder than normal, gas consumption could increase by an additional 3.6 bcf per day--or 5.1 percent--from the base case, rising to 74.0 bcf per day. Production would increase by at most 1.0 bcf per day to 52.8 bcf per day, and imports would increase by 0.5 bcf to 10.1 bcf per day. Increased withdrawals from storage would rise 2.6 bcf per day to 13.3 bcf per day. End-of-season working gas stocks would be 525 bcf, or half the stocks of a normal winter. (It should be noted that increased production and imports would theoretically not be necessary to meet the requirements of a cold winter, because working gas alone could supply the entire incremental requirements with 343 bcf to spare). Realistically, though, the price reaction to such a severe draw on stocks would be hard to predict and is likely to be quite large. At a minimum, with the increased demand, wellhead prices would move up by at least $0.20 per mcf to average $2.70 or more, and residential prices would increase by $0.13 to average $7.06 per mcf. Residential demand would increase by 1.8 bcf per day, or 9 percent. The combined impact of higher demand and prices resulting from a severe winter would raise the average space-heating bill by 10 percent above the bill for the base case for the typical gas-heated household (Table WF01).

A winter that is 10 percent warmer than normal would lower total natural gas consumption from that of the base case by 4.6 bcf per day, or 6.5 percent, to 65.8 bcf per day, lower than last year's consumption. Residential demand would decline by 1.7 bcf, or 9 percent, to 18.9 bcf per day. Withdrawals from storage would average 7.8 bcf per day, 2.9 Bcf per day less than under normal weather, leaving end-of-season working gas inventories of 1,536 bcf. Wellhead prices under this scenario are projected to average $2.37 per mcf, $0.13 lower than under normal weather conditions. Last winter, when temperatures were more than 20 percent warmer than normal some days, the average price of gas at the wellhead dropped to $1.73 per mcf in February. In a warmer-than-normal winter, the price to residential consumers would average $6.89 per mcf, $0.04 less than under the assumptions of a normal winter.

Heating Oil

Cold or Not, Expect Higher Fuel Bills

In the wake of a doubling of oil prices since the beginning of this year, sharp increases in heating oil expenditures can be expected this winter, even if temperatures turn out to be as warm as those during the previous winter. As much as anything else, this fact reflects the extraordinarily depressed level of crude oil and petroleum products prices last winter, brought about by economic weakness in several emerging markets. The base case forecast, which assumes normal weather, yields average heating oil prices and demand levels similar to those seen in the winter of 1996-1997.

Demand

Winter demand for distillate fuel is projected to be 3.70 million barrels per day, 130,000 barrels per day, or 3.4 percent, above the 1998-1999 level in the base case. The expectation of normal winter weather in the Northeast, the principal region for heating oil, would bring about a 6.9 percent increase in heating degree-days per day in that region and a corresponding increase in heating oil demand. As it turns out, much of the year-to-year increase in heating-degree days is expected to occur in the fourth quarter of 1999. For the peak winter quarter, heating-degree days are expected to be only 3.4 percent higher than in the first quarter of 1999. Meanwhile, adding to the overall expected increases in distillate demand, growth in transportation-related demand is expected to be about 100,000 barrels per day, or 4.5 percent.

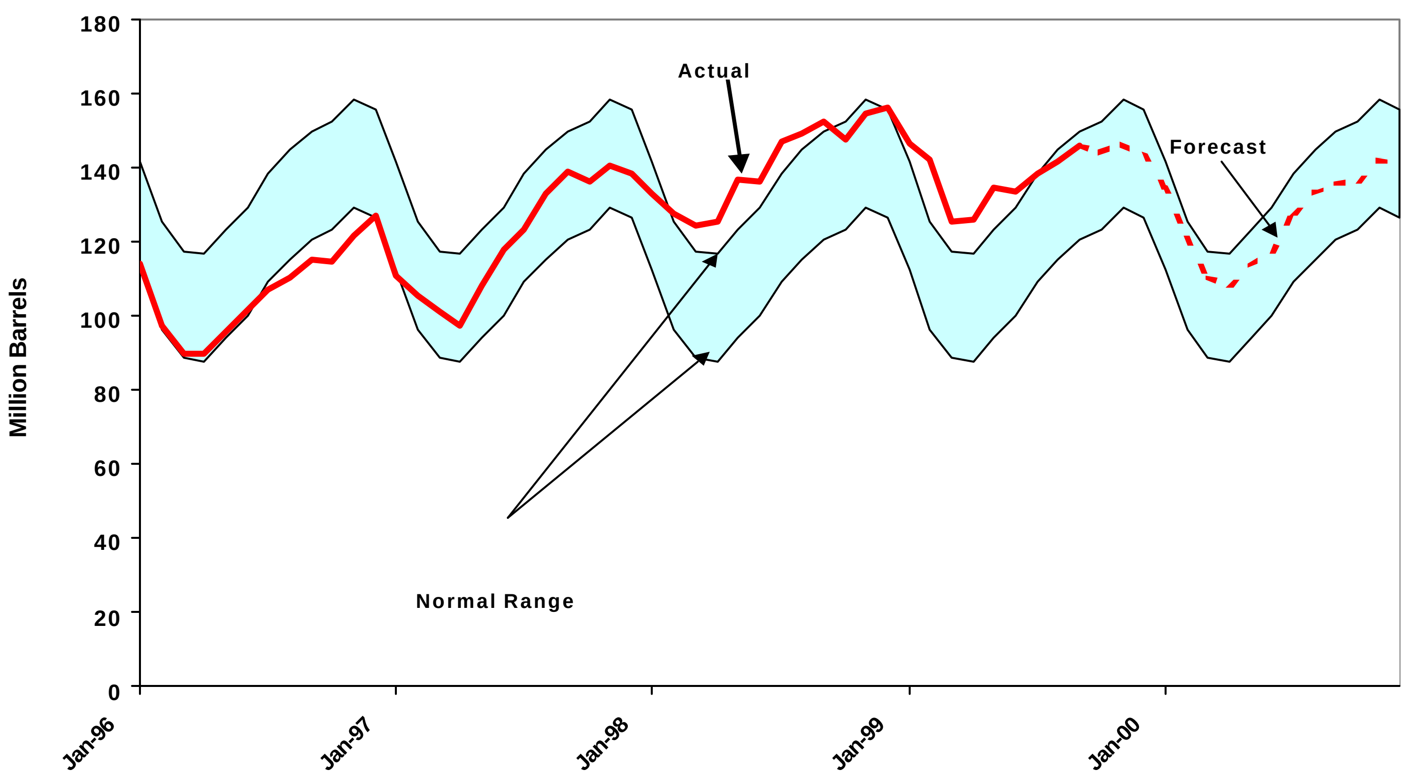
Supply

The three sources of supply--domestic refinery production, net imports and primary stock withdrawals--should be adequate to meet the needs of both a normal and a severe winter. This winter season, refinery production of distillate is projected to average 3.40 million barrels per day, up 110,000 barrels per day from the previous winter's production. Despite steady increases in refinery capacity, average utilization during the winter season is projected to be only 91.5 percent, down from 92.1 percent last winter season and 94.8 percent during the 1997-98 winter season. Net imports are expected to average 100,000 barrels per day, or 2.7 percent of total winter requirements, compared to imports of 140,000 barrels per day, or 3.9 percent of total winter requirements, during the previous heating season.

The heating season is expected to begin with 146 million barrels in primary storage (Figure WF8). Although 7 million barrels less than last winter's beginning-of-season stocks, they are 4 million barrels higher than in stocks were in 1997 and 10 million barrels above the average of the previous 5 years. Nonetheless, the combination of projected higher demand and lower stocks portend a tighter supply/demand balance than during the last winter season. The average stock withdrawal is projected to be 200,000 barrels per day, up slightly from the 150,000 barrels per day last winter. As a result, end-of-season stocks are projected to be 110 million barrels compared to 125 million barrels last winter.

Although severe weather can be expected to result in increased refinery production and imports, it should be noted that a sufficient drawdown in stocks alone could accommodate the increased requirements of a severe winter. At the end of such a winter, stocks would be 99 million barrels, still above the low of 90 million barrels recorded at the end of the 1995-1996 heating season.

Figure WF8. U.S. Distillate Fuel Stocks



Prices

Whether or not strong heating oil demand conditions appear this winter, the rise in crude oil prices virtually assure much higher heating oil prices this winter. Residential heating oil prices are projected to average $1.09 per gallon this winter in our base case, up 29 cents from last winter's average price. This is a very significant increase, but it should be kept in mind that last winter's average of 80 cents per gallon was extraordinary and clearly reflected the sharp decline in crude oil prices. Essentially all of the increase--29 cents per gallon--stems from the rise in crude oil prices brought about by OPEC's ability to reverse last year's oil price slide at a time when emerging markets were able to stage at least the beginnings of an economic recovery, bringing about an increase in oil demand.

Crude oil costs to U.S. refineries are projected to average 55.5 cents per gallon ($23.57 per barrel), more than double the depressed levels seen in the previous winter. This projection assumes that OPEC producers maintain a high level of compliance with the previously announced cuts, as reiterated at their Ministerial Meeting on September 22. The projected oil prices also assume that any increases in aggregate non-OPEC production in response to the higher prices will be insufficient to offset the bullish sentiment engendered by OPEC's restraint during the heating season. Nevertheless, there remains much uncertainty about oil prices this winter, even with normal weather.

Because the current bullish sentiment rests on the assumption that world-wide oil inventories are being drawn down at a rapid rate, a much colder-than-normal winter would stoke an additional increase in demand and accelerated withdrawals, raising crude oil and products prices during the first quarter of 2000. Warm weather, on the other hand, would deflate expectations that the currently high prices can be maintained during the winter. Figure WF1 depicts this source of crude oil volatility brought about by alternative weather scenarios.

Assuming a normal winter, residential heating-oil costs would be expected to rise from those of the previous winter (Table WF01). The bulk of that increase, however, reflects the sharp increase in crude oil prices from those of last winter. A severe winter, however, could increase the average residential fuel bill by an additional 28 percent.

Propane

Assumption of Normal Weather Expected to Boost Demand

The primary factors that affect propane demand in the United States are propane prices, crude oil and natural gas prices, macroeconomic growth and weather. Because of the influence of the highly weather-dependent residential sector, total propane demand generally mirrors the same seasonal patterns as the residential sector, rising during winter months and falling during the spring and summer months.

Last winter's mild temperatures contributed to propane demand being nearly flat compared with the 1997-1998 heating season's demand. However, assuming winter temperatures return to normal, weather-related demand for propane is expected to increase over the 1998-1999 heating season level.

U.S. demand for propane averaged about 1.36 million barrels per day during the 1998-1999 winter heating season, less than 1 percent below the previous year's heating season, as was expected due to the modest decline in heating degree-days. However, the assumption of higher demand this winter is bolstered by the robust growth in propane demand experienced so far during 1999. Through July 1999, U.S. demand for propane averaged 1.2 million barrels per day, up more than 9 percent from demand during the same period last year. Despite the mild beginning of winter last year, the first quarter of 1999 was much colder, a factor which boosted residential heating demand. Combined with continued strong petrochemical feedstock demand for propane through the first half of 1999, propane demand soared to its highest year-to-date level ever.

Propane demand for the remainder of 1999 is not expected to face any significant changes in the market environment from that experienced earlier in the year. Although a return to normal weather patterns following last winter's milder temperatures is expected to increase residential heating demand, other sector demand requirements, such as for crop drying and petrochemical feedstock use, are not expected to add any upward pressure on the level of demand for the remainder of 1999.

Supply Remains Adequate

Demand for propane is met by domestic production at gas processing plants and at refineries, inventory withdrawals, and net imports. During the heating season, domestic production typically supplies about 80 percent of supply, while inventories and imports supply the remaining 20 percent share of supply. Moreover, the level of production at both gas processing plants and at refineries is relatively inelastic to short-term changes in price and demand. This is due to its by-product status at these facilities.

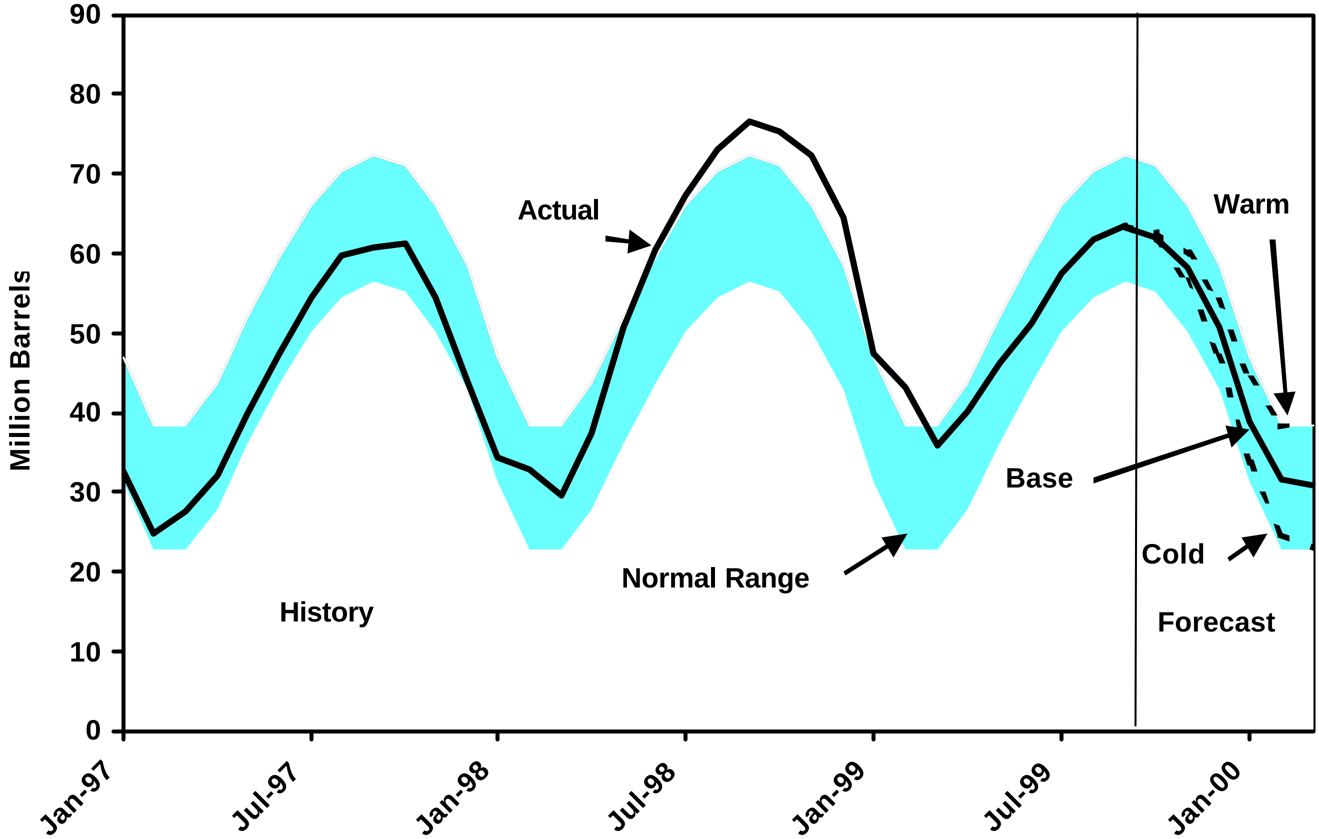
Total propane production through July 1999 averaged nearly 1.1 million barrels per day, relatively unchanged from production in the comparable period last year. Production at gas processing plants fell slightly from year-over-year levels through July, while production at refineries moved slightly above comparable year-ago levels. Poor extraction economies at gas processing plants continued to plague the industry during the early months of 1999, causing processors to leave a larger portion of the propane in the natural gas stream. However, processing levels may improve over the remainder of the year if natural gas liquid prices keep pace with escalating natural gas prices. Refineries have accounted for most of the annual growth in propane production over the past several years due to high refinery runs from strong gasoline production. Refinery supplied propane is expected to remain strong through the end of the year, an outcome which, in turn, is contingent on an expanding U.S. economy.

Primary inventory withdrawals provide the second largest source of propane during the winter heating season. The level of inventories also represents the imbalance of supply and demand, which explains why inventories are built up during the spring and summer months, when demand is typically at its lowest level. These factors may help explain why the buildup of U.S. inventories through September last year was the largest ever, measuring nearly 47 million barrels. This compares with a 5-year average stock build of 34 million barrels. A mild winter, which lowered demand and left U.S. inventories at their highest March level in 6 years, along with record imports, combined to push up U.S. inventories to their highest pre-heating season level since 1986.

The U.S. stock build for the 1999-2000 heating season measured approximately 28 million barrels, significantly lower than last year's record stock build but still large enough to raise inventories to adequate levels by the start of the heating season. As of September 30, 1999, U.S. inventories of propane stood at an estimated 63 million barrels, the second highest level for this month since 1986.

Regionally, inventories remain within their respective normal ranges in the Midwest and the Gulf coast regions, while, in the East Coast, inventories remain slightly above the normal range for this time of year (Figure WF10).

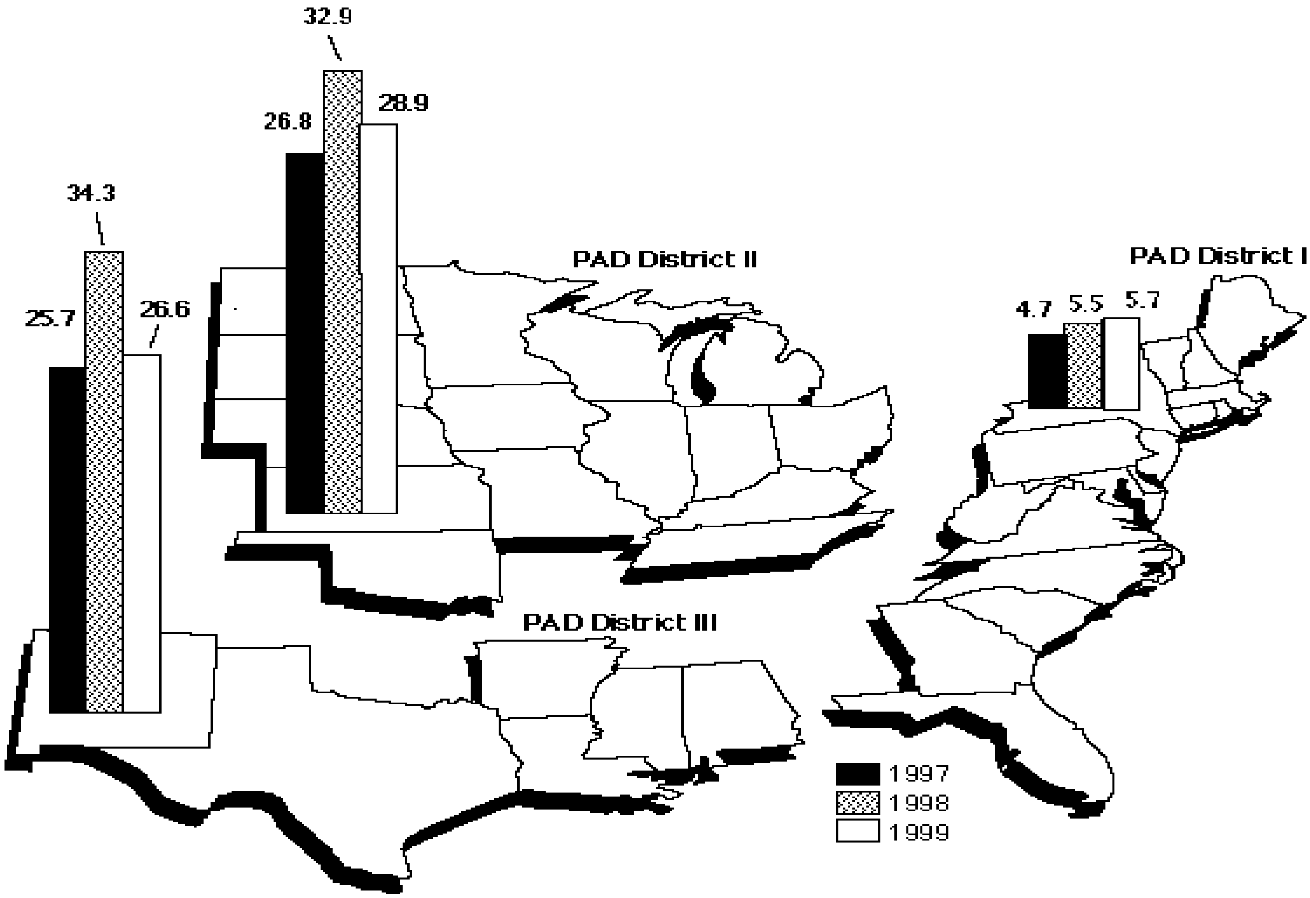
Figure WF9. U.S. Propane Stocks



On the basis of current inventory levels and projected supply and demand, the expectation for the 1999-2000 winter heating season is for adequate supplies but higher prices, given normal weather and the absence of any major supply problems. Under a base case scenario, stocks are projected to gradually decline over the course of the season, reaching a level of about 31 million barrels by the end of March 2000 (Figure WF9).

While small in volume, imports provide a crucial source of supply during periods when consumption rates exceed the rates of available supplies from production and inventories. Propane imports are significantly down this year compared with last year's record volume. Through July, propane imports averaged 115,000 barrels per day, 40,000 barrels per day lower than they were during the same 7-month period last year. However, imports during 1998 were abnormally high, as surplus world supply, due to weak demand in both Europe and Asia, caused imports to flood into the United States. Moreover, year-to-date imports through July 1999 were only 2,000 barrels per day below the comparable 5-year average of 117,000 barrels per day.

Figure WF10. U.S. Propane Inventories by PAD District (as of September 30)
(million barrels)



Prices Rebound

Propane prices at all levels of the distribution chain are subject to a number of influences. The primary determinant of spot propane prices, as with most commodities, is the balance of demand and available supply, often on a regional basis. Additionally, propane prices are influenced by crude oil and natural gas prices, competition with other commodities used as fuel or feedstock, and intangible factors, such as uncertainty about future supply or demand.

Residential propane prices are expected to be much higher this year compared with prices last year. Last year's high stocks and relatively mild weather caused both wholesale and residential propane prices to remain unseasonably low for most of the 1998-1999 heating season. However, since April 1999, spot propane prices have increased significantly in response to rising crude oil prices. Under the base case scenario, average residential prices would be expected to increase seasonally from about 96 cents per gallon in September to a winter peak of $1.12 per gallon in February. Prices would then drift lower and end the season at $1.09 per gallon (Figure WF11).

Severe Weather Scenario

This scenario assumes that weather, in terms of heating degree-days, will be 10 percent colder than normal (base case) for the entire heating season (October 1999 through March 2000). Such a heating season would be substantially colder than last winter's relatively mild weather.

In this scenario, propane inventories would be projected to end the heating season at about 23 million barrels, nearly 8 million barrels lower than in the base case scenario. The impact of this scenario on residential prices would be significant. With cold weather concentrated in the second half of the season, a shorter period would exist for incremental supplies of propane from production and imports to respond to the higher demand during the peak winter months. The projected result would be to reach a maximum price in February of about $1.21 per gallon, and decline to about $1.17 per gallon by March 1999, roughly 7 cents over the base case.

Mild Weather Scenario

This scenario assumes that weather, in terms of heating-degree days, will be 10 percent warmer than normal throughout the coming heating season. Under this scenario, U.S. propane stocks would be projected to end the heating season at about 39 million barrels. This level would be nearly 8 million barrels above the level of the base case scenario and 16 million barrels above the level of the severe case scenario. The impact on residential price would be much less pronounced, which would rise to a season high of $1.04 cents per gallon by February, then decline to $1.02 per gallon by March 2000.

Figure WF11. Residential Propane Price: Weather Cases

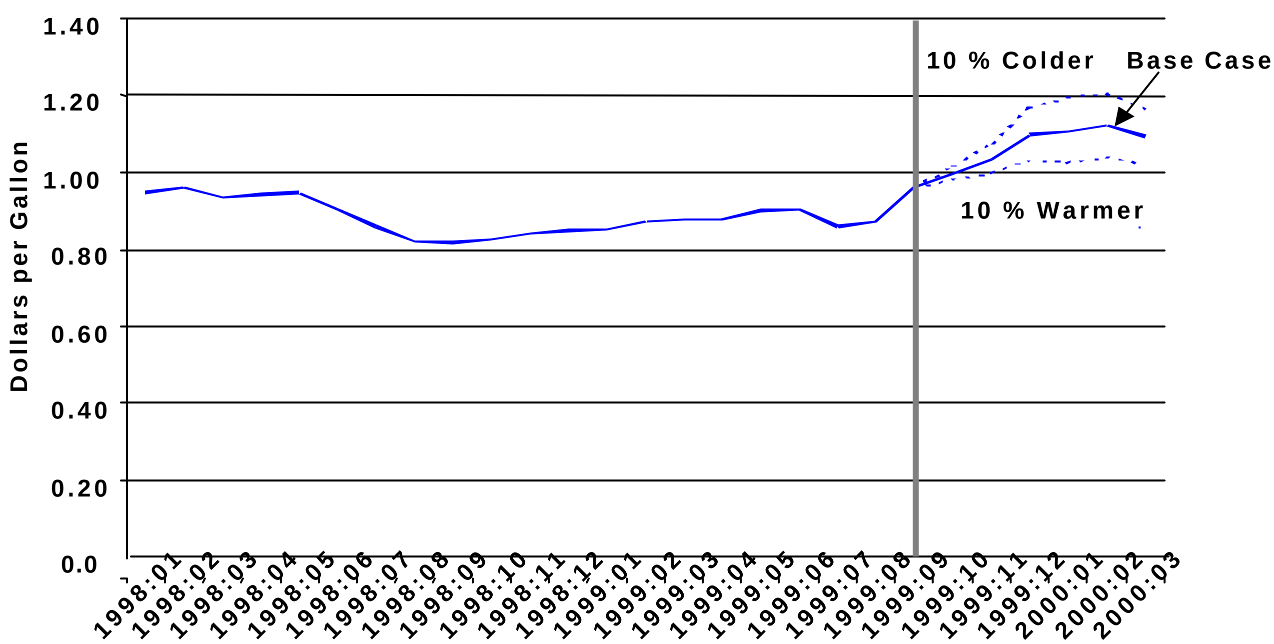


Table WF02. U.S. Winter Fuels Outlook: Base Case and Weather Cases

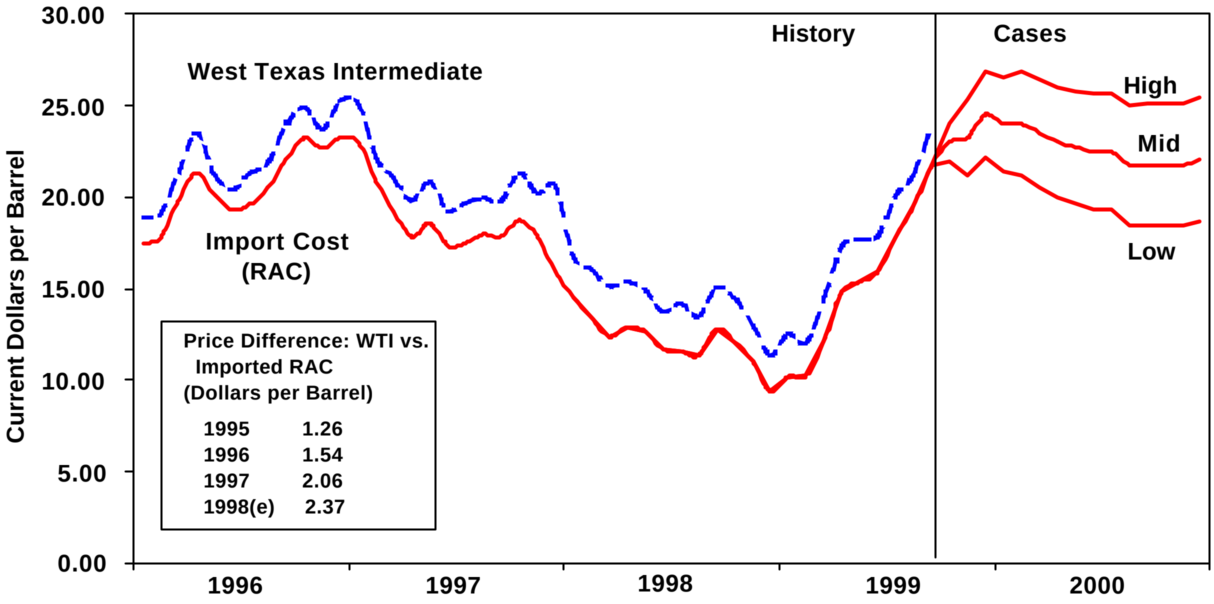
	History			Base Case							
	1998-1999			1999-2000			Percent Change[d]			Severe	Mild
	Q4	Q1	Winter	Q4	Q1	Winter	Q4	Q1	Winter	Winter	Winter
Demand/Supply											
Distillate Fuel (mill. barrels per day)											
Total Demand	**3.45**	**3.70**	**3.58**	**3.63**	**3.76**	*3.70*	*5.2%*	*1.7%*	*3.4%*	*3.80*	*3.61*
Refinery Output	**3.36**	**3.21**	**3.29**	**3.54**	**3.27**	*3.40*	*5.3%*	*1.7%*	*3.5%*	*3.46*	*3.38*
Net Stock Withdrawal	**-0.04**	**0.34**	**0.15**	**0.03**	**0.36**	*0.20*	*NM*	*6.3%*	*30.5%*	*0.24*	*0.13*
Net Imports	**0.13**	**0.15**	**0.14**	**0.07**	**0.13**	*0.10*	*NM*	*-10.6%*	*-28.5%*	*0.10*	*0.10*
Refinery Utilization (percent)	**93.1%**	**91.1%**	**92.1%**	**92.7%**	**90.5%**	*91.6%*				*92.1%*	*91.1%*
Natural Gas (bill. cubic feet per day)											
Total Demand	**58.01**	**75.20**	**66.51**	**61.66**	**79.25**	*70.41*	*6.3%*	*5.4%*	*5.9%*	*74.00*	*65.76*
Production	**51.24**	**51.24**	**51.24**	**51.21**	**52.40**	*51.80*	*-0.1%*	*2.3%*	*1.1%*	*52.82*	*50.81*
Net Stock Withdrawal	**2.51**	**14.31**	**8.35**	**5.35**	**16.08**	10.68	*113.0%*	*12.3%*	*28.0%*	13.28	7.75
Net Imports	**8.24**	**9.26**	**8.74**	**9.32**	**9.79**	*9.55*	*13.1%*	*5.8%*	*9.3%*	*10.06*	*9.09*
Propane (mill. barrels per day)											
Total Demand	**1.27**	**1.45**	**1.36**	**1.34**	**1.42**	*1.38*	*5.5%*	*-2.1%*	*1.5%*	*1.36*	*1.26*
Net Stock Withdrawal	**0.13**	**0.32**	**0.22**	**0.14**	**0.22**	0.18	*6.6%*	*-31.9%*	*-20.5%*	*0.22*	*0.14*
Stocks (ending period)											
Distillate Fuel (MMB) - Beg. [a]	**153**	**156**	**153**	**146**	**143**	*146*	*-4.4%*	*-8.3%*	*-4.4%*	*143*	*143*
- End. [a]	**156**	**125**	**125**	**143**	**110**	*110*	*-8.3%*	*-12.1%*	*-12.1%*	*99*	*119*
Working Gas (BCF) - Beg. [b]	**2949**	**2718**	**2949**	**2955**	**2463**	2955	*0.2%*	*-9.4%*	*0.2%*	*2955*	*2955*
- End. [b]	**2718**	**1430**	**1430**	**2463**	**1000**	1000	*-9.4%*	*-30.1%*	*-30.1%*	*525*	*1536*
Propane (MMB) - Beg. [a]	**76.6**	**64.6**	**76.6**	**63.4**	**50.6**	*63.4*	*-17.3%*	*-21.7%*	*-17.3%*	*63.4*	*63.4*
- End. [a]	**64.6**	**35.9**	**35.9**	**50.6**	**30.8**	*30.8*	*-21.7%*	*-14.1%*	*-14.1%*	*22.9*	*38.6*
Prices											
Imported Crude Oil (c/g) [c]	**25.9**	**26.0**	**25.9**	**56.1**	**56.7**	*56.4*	*117.0%*	*118.3%*	*117.7%*	*58.4*	*42.4*
Retail Heating Oil (c/g)	**79.2**	**80.4**	**79.8**	**106.4**	**111.5**	*108.9*	*34.3%*	*38.7%*	*36.5%*	*119.8*	*98.1*
Wellhead Gas ($/mcf)	**1.84**	**1.74**	**1.79**	**2.60**	**2.39**	*2.50*	*41.5%*	*37.3%*	*39.4%*	*2.72*	*2.37*
Resid. Gas ($/mcf)	**6.64**	**6.09**	**6.28**	**7.23**	**6.75**	*6.93*	*9.0%*	*10.8%*	*10.2%*	*7.02*	*6.89*
Resid. Propane (c/g)	**84.1**	**86.6**	**85.4**	**104.8**	**110.9**	*107.9*	*24.6%*	*28.0%*	*26.3%*	*114.1*	*101.7*
Market Indicators											
Manuf. Output (index, 1992=1.0)	**1.364**	**1.369**	**1.367**	**1.404**	**1.392**	*1.398*	*2.9%*	*1.6%*	*2.3%*	*1.398*	*1.398*
Northeast HDDs per day	**20.1**	**32.0**	**25.9**	**22.5**	**33.1**	27.7	*11.9%*	*3.4%*	*6.9%*	*30.5*	*25.0*
Gas-Weighted HDDs per day	**16.7**	**25.3**	**20.9**	**18.6**	**26.1**	22.4	*11.9%*	*3.4%*	*6.9%*	*24.6*	*20.1*

[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 CONTROL0999.

The Outlook

Outlook Assumptions

Figure 1. U.S. Monthly Crude Oil Prices



World Oil Prices

World oil prices for the remainder of 1999 and all of 2000 are now forecast to be above $20 per barrel (Figure 1). On the assumption that OPEC compliance will remain strong through at least most of the winter period, EIA believes that prices will rise from average September levels (an estimated $21.50 per barrel for the price paid by U.S. refiners for imported crude oil or $23.75 per barrel for West Texas Intermediate crude oil) by $1 to $2.50 per barrel by the December-through-March 2000 period. This forecast assumes that OPEC production remains relatively flat for most of the winter, but that OPEC production begins to creep up slowly, leading up to OPEC's scheduled ministerial meeting in March 2000. This production profile should draw down world oil stocks to well below normal levels by the end of the winter period.

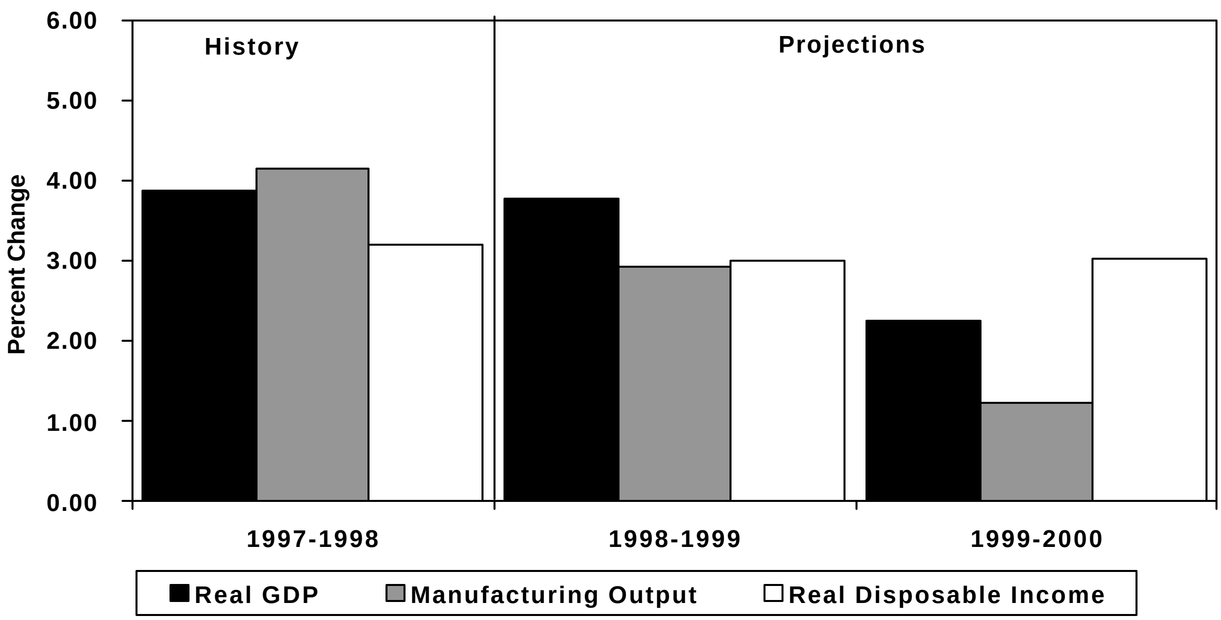
While it is impossible to predict whether OPEC will increase production quotas at the March 2000 meeting, this forecast assumes continued increases in OPEC production over the course of 2000. The increases are not expected to be large enough to allow the average price paid by refiners for imported crude oil to slip below $20 per barrel (equivalent to a West Texas Intermediate crude oil price of about $22 per barrel). Of course, if OPEC production in 2000 exceeds this forecast, lower prices would be expected. Our normal uncertainty range for crude oil prices suggests that expected end-2000 prices would be within about $3-$3.50 of the $20.50 per barrel level with a high degree of probability (Figure 1).

Economic Outlook

In 1999, GDP is expected to continue to grow at the rate of 3.8 percent, close to the 3.9 percent it grew in 1998. In 2000, GDP is projected to continue to grow but at the slower pace of 2.2 percent. Personal disposable income is assumed to be up by 3.0 percent in 1999 from its 1998 level, and up by another 3.0 percent in 2000. This is somewhat below the 3.2 percent growth seen in 1998 (Figure 2 and Table 1).

Inflation (consumer price index: see Table 2) should rise somewhat over the next two years. Consumer price inflation is expected to be 2.3 percent in 1999, up significantly from the 1.6 percent in 1998 (Table 1) and rise again by 2.8 percent in 2000. Manufacturing production is expected to grow by 2.4 percent in 1999 and by 1.6 percent in 2000, compared with 3.6 percent in 1998, as investment growth decelerates and exports decline. Total employment will increase slowly over the forecast period.

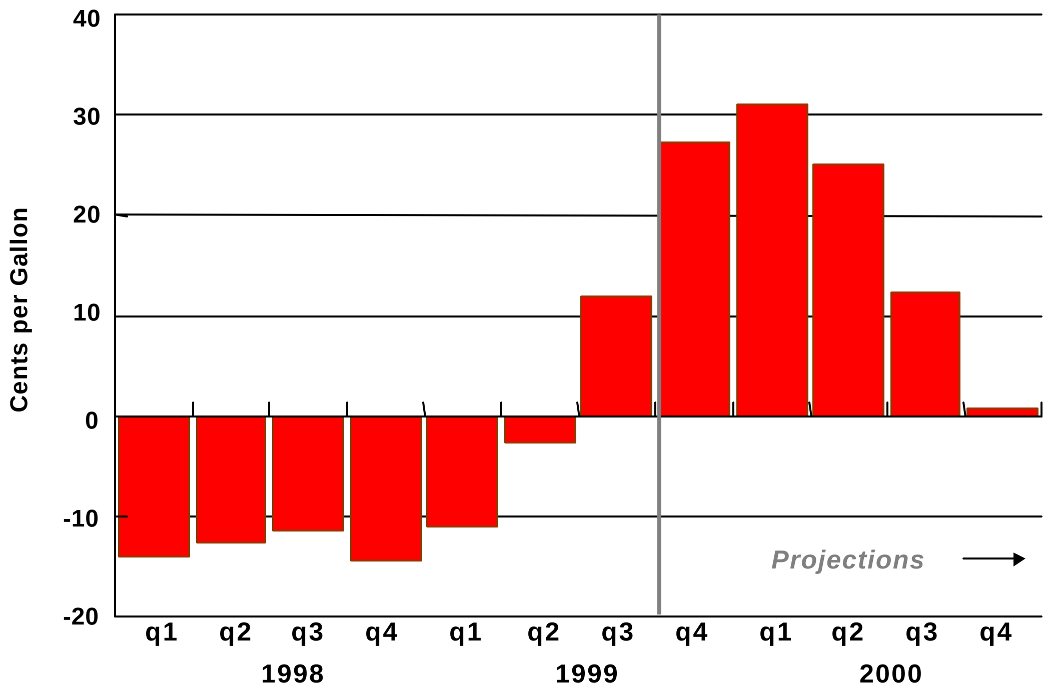
Figure 2. U.S. Macroeconomic Indicators



Weather Assumptions

Weather patterns (expressed as heating and cooling degree-days in Table 1) are assumed to follow historical norms during the remainder of 1999 and in 2000. This would imply that, for this winter, heating degree-days would be 8.0 percent above 1998 levels.

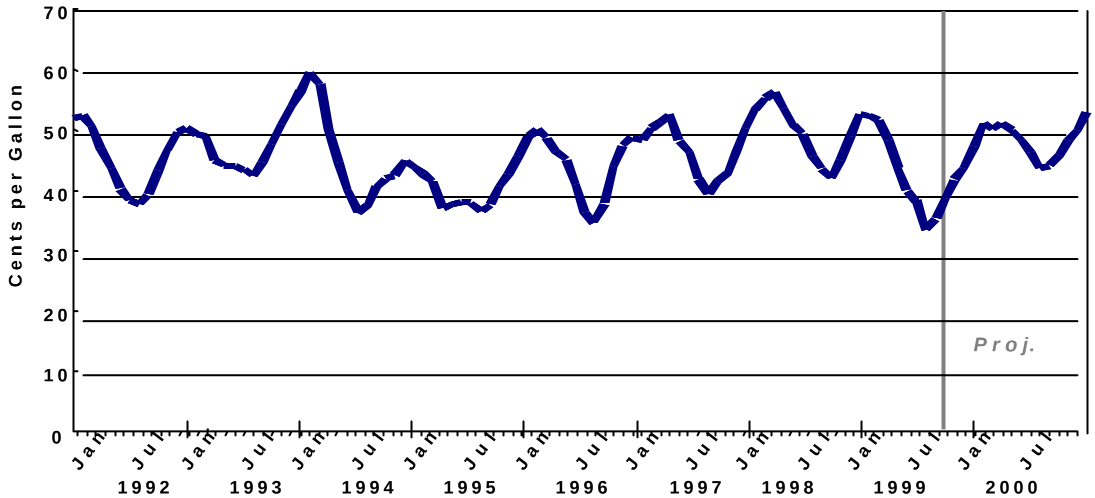
Figure 3. Quarterly Retail Heating Oil Prices (Change from Year Ago)



Average crude oil prices will probably rise by over $5.00 per barrel this year and are expected to rise by an additional $5.00 per barrel next year. One reason for the relative size of the price increase is that crude oil prices started from a low base. In 1998, crude oil prices crashed to near historical lows in real terms. In any case, the increasing crude oil prices will lead to higher petroleum product prices through the next year. We should expect to see petroleum product price annual increases averaging around 10 cents or more per gallon for both 1999 and 2000 (Table 4). The upcoming winter quarter price increases will be noticeably pronounced due to the concurrent sharp price rise of crude oil.

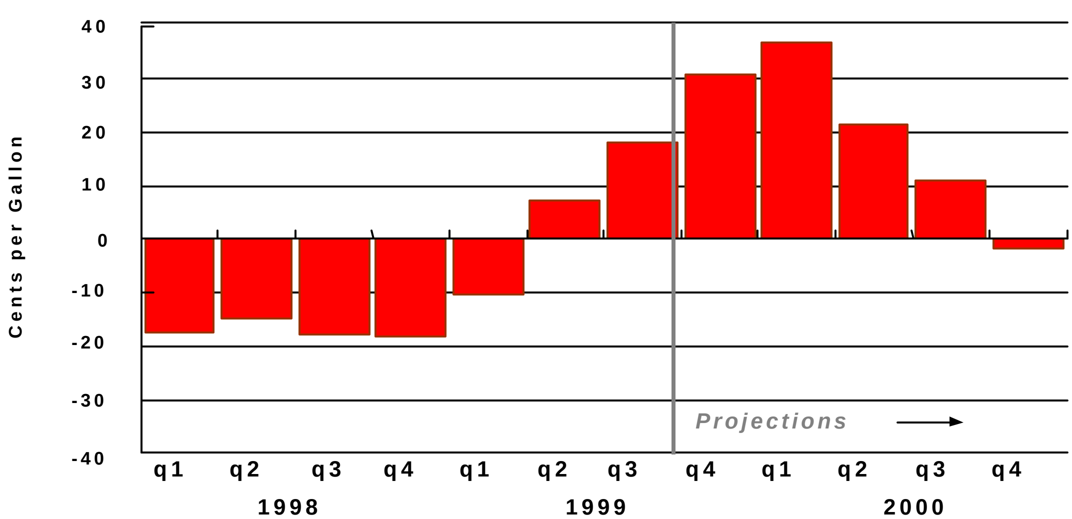
Residential heating oil prices were at bargain levels last winter, when crude oil prices were low and the weather, on average, was warmer than normal. This winter, assuming normal weather and the higher crude oil price path, heating oil consumers can expect to pay about 30 cents per gallon more compared to last winter to heat their homes, or an increase of more than 36 percent (Figure 3 and Table 4). Although the impending price increase may seem high, it is due almost entirely to higher projected crude costs. A way to illustrate this is to compare the retail price spreads over time. The spread is the difference between the residential price and the refiner acquisition cost for crude oil. As Figure 4 shows, the spread is fairly constant, increasing almost imperceptibly from 1992 through the year 2000.

Figure 4. Retail Heating Oil Spreads (Monthly: 1992-2000)



Motor gasoline prices will exhibit a type of behavior similar to heating oil prices this winter, increasing by more than 30 cents per gallon from prices during the same period a year ago, for the same reason--higher crude prices. Last February, retail motor gasoline prices--unleaded regular, self-service, cash--reached an historical low when adjusted for inflation, largely because of the low world oil prices at the time. Pump prices have been climbing since then and are projected to peak this year in December at $1.31 per gallon, an increase of 39 cents per gallon from the February low. Next year, prices at the pump are projected to rise again, with an annual increase of about 17 cents per gallon. However, the price gain between 4th quarter of this year and the highest quarterly price for next year should be only a few cents per gallon (Figure 5 and Table 4).

Figure 5. Quarterly Retail Motor Gasoline Prices* (Change from Year Ago)



*Regular Unleaded, Self-Service Cash

Natural gas spot and near-term futures wellhead prices have been quite volatile since August, with gas storage observers exhibiting a degree of skittishness over the level of underground storage going into the heating season. Our analysis indicates that storage levels are about at the relatively robust levels of one year ago; thus wellhead prices this winter are not projected to be as high as the futures market presently indicates. Nevertheless, it is fairly certain that the wellhead price this winter will be considerably higher than last winter's price of about $1.80 per thousand cubic feet simply because last year's mild winter, coupled with low oil prices, kept the lid on the price of natural gas. Assuming normal weather, this winter natural gas wellhead prices are projected to average about 40 percent more than last winter's (Figures 6 and 7). Residential prices over the same period are projected to be about 10 percent higher.

Figure 6. Natural Gas Wellhead Prices (Composite and Spot)

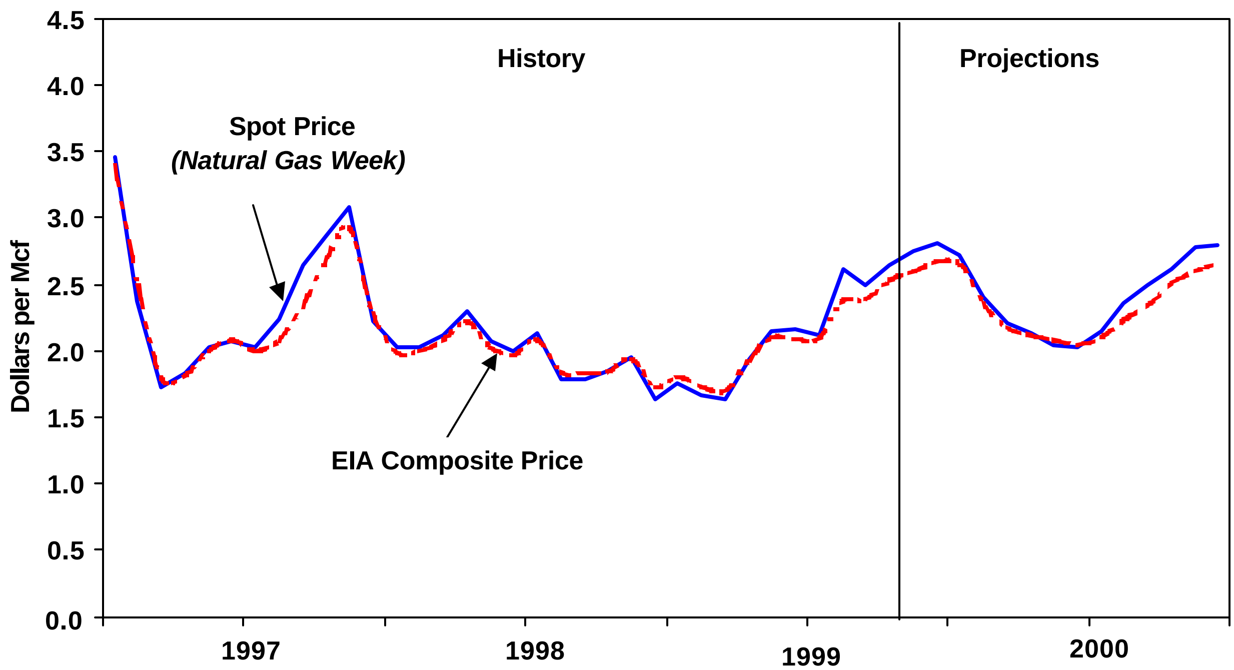
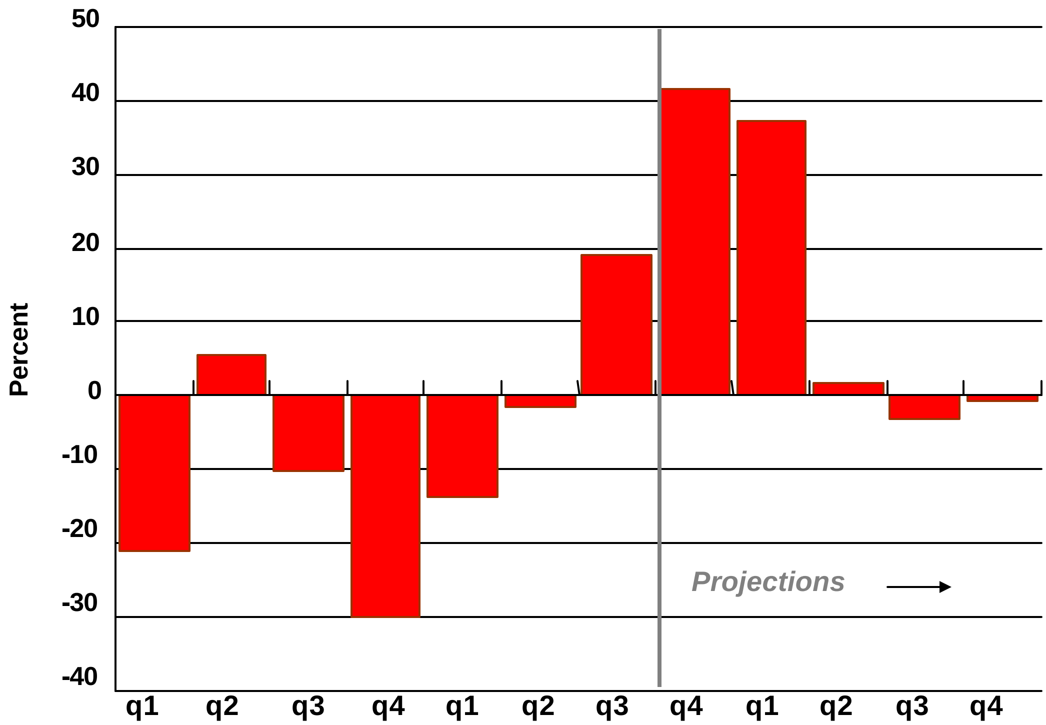
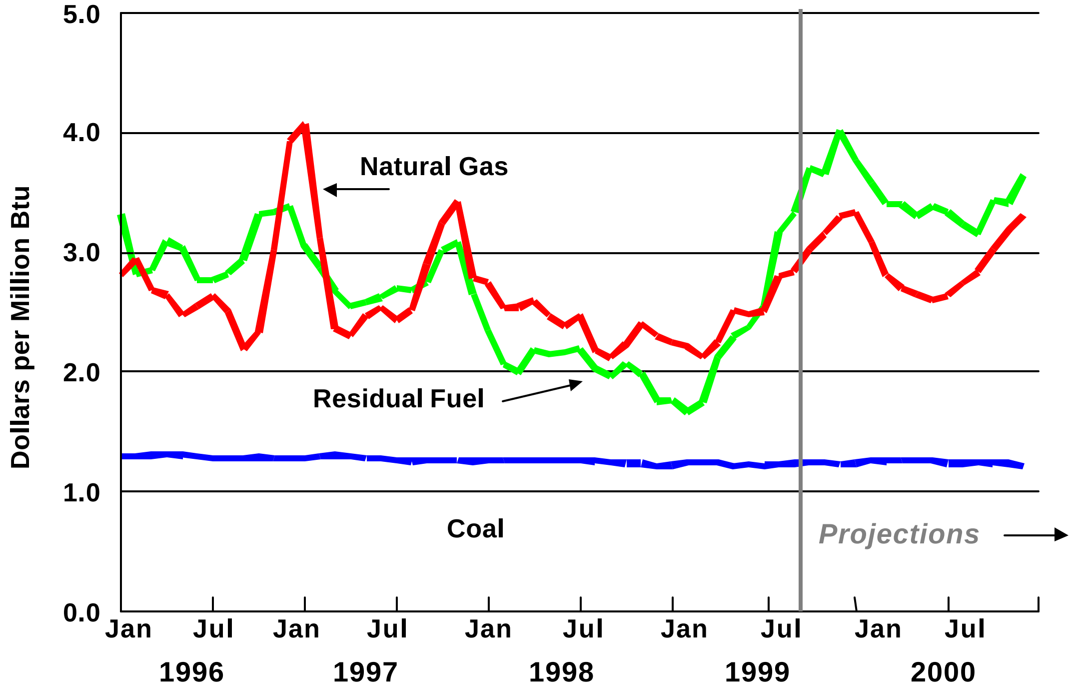


Figure 7. Quarterly Natural Gas Wellhead Prices (Percent Change from Year-Ago)



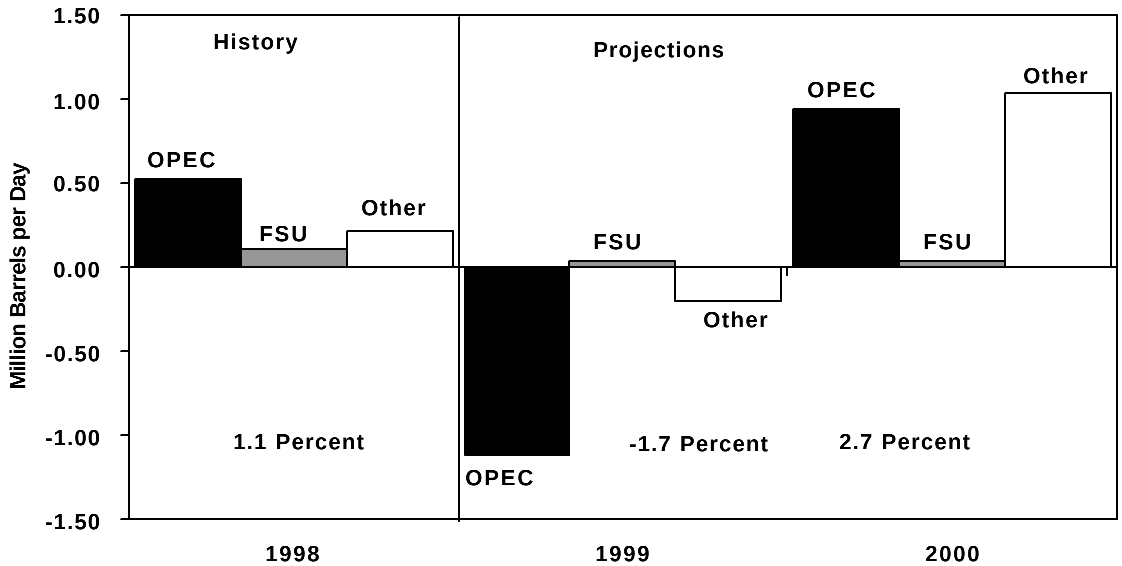
In 1998, the average annual residual fuel oil price to electric utilities fell below the natural gas price (to electric utilities) for the first time since 1993, giving heavy oil the price advantage for electricity generation (Figure 8 and Table A4). This price advantage has since evaporated and is not expected to return during the forecast period. The prices of both fuels are projected to increase in the year 2000, with the residual fuel oil price increasing much faster, assuming our base crude oil price path holds. Coal remains by far the least expensive fossil fuel for electric utilities (Table 4 and Figure 8). Coal prices are expected to decline through 2000 even after costs associated with compliance with the Clean Air Act Amendments of 1990 are included. Continued increases in mining productivity, including longwall mining, as well as the closing of costly marginal mines, particularly those East of the Mississippi, have kept coal supply costs on a gradually declining trend for many years.

Figure 8. Fossil Fuel Prices to Electric Utilities



International Oil Supply

Figure 9. World Oil Supply (Changes from Previous Year)

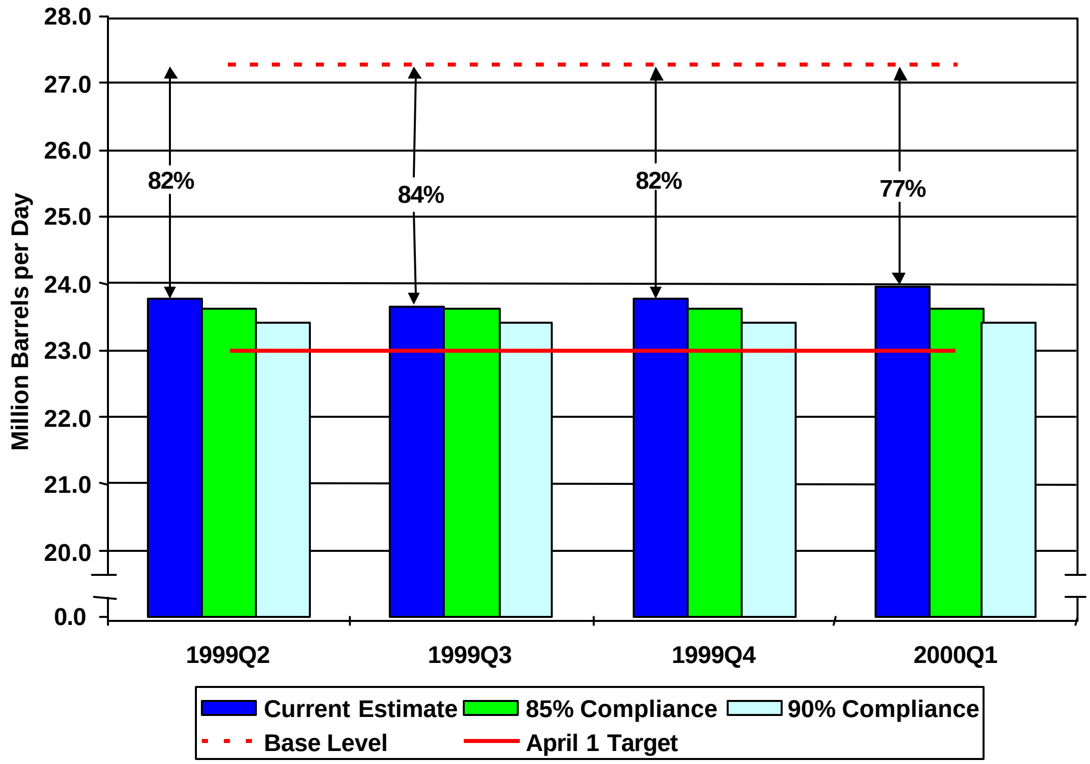


On September 22-23, 1999, for the first time since March 1998, OPEC held a ministerial meeting where they did not pledge additional oil production cuts. But with oil prices about double what they were as recently as February 1999, there was no incentive for additional cuts. Even without additional production cuts, EIA is estimating that OPEC oil production this winter will average 1 - 1.5 million barrels per day less than in February 1999. This, in spite of the fact that Iraqi oil production is expected to average about 300,000 barrels per day more this winter than in February 1999. The cuts in production made by OPEC and a few non-OPEC member countries, notably Mexico and Norway, have already had the effect they were desired to have, raising prices to above $20 per barrel. The question now is no longer if OPEC plans additional production cuts in the future, but, instead, when will they raise production targets now that prices have risen beyond even their expectations? As the graph above shows, this price increase is not expected to increase non-OPEC production significantly in 1999. However, by 2000, prices should be high enough for a long enough period to expect significant increases in non-OPEC production once again. Of course, OPEC is also expected to gain back more oil production in 2000 than it lost in 1999 (Figure 9).

OPEC's continued strong compliance with earlier production cuts is expected to have a large impact on world oil inventories (Figure 10). There are various estimates of world oil stock levels and the amount of excess global oil stocks that existed this summer and different analysts peg the excess global oil inventories between 200 and 400 million barrels. Beginning in the 2nd quarter of 1999, the EIA forecast expects about 350 million barrels to be drawn down by the end of

1999. This draw is already larger than some estimates of the excess inventories and nearly as much as the largest estimate of excess global oil stocks. This implies that by the end of 1999, the global oil stock situation will either be at or below normal levels. By the end of the 1st quarter of 2000 (the end of the 1999/2000 winter), global oil inventories will have been drawn down well below the excess level of global inventories, regardless of whose estimates you assume. As stated above, this global oil inventory situation reflects slight increases in OPEC production in the first quarter of 2000. If OPEC compliance increases, excess global oil inventories could be drawn down by as early as the end of this year, and prices would likely be at least $2-$3 per barrel higher than prices in our base case forecast during the winter of 1999/2000).

Figure 10. OPEC Compliance to Agreed Upon Cuts in Crude Oil Production

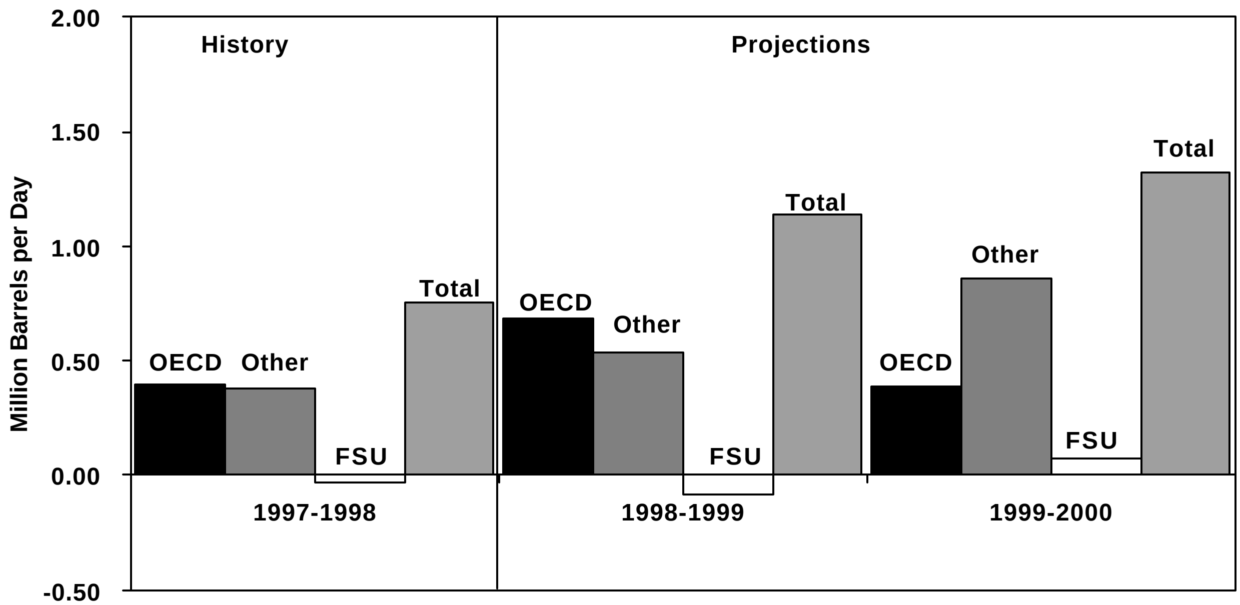


For the purposes of this forecast, we have assumed Iraqi crude oil production to increase from current levels of about 2.85 million barrels per day, to over 3.0 million barrels per day on average in the first half of 2000. Iraqi crude oil production is then assumed to average 3.1 million barrels in the second half of 2000. This is merely an assumption for this forecast and does not reflect any official U.S. government view on the future of Iraqi oil exports. It should be noted that this forecast of Iraqi oil production and prices implies that Iraqi oil exports would exceed the current limit of $5.256 billion dollars every 180 days that are allowed under current United Nations sanctions.

After growing on average by nearly 1 million barrels per day in 1995, 1996, and 1997, non-OPEC oil supply increased by only 300,000 barrels per day in 1998 and is forecasted to decline by nearly 200,000 barrels per day in 1999. Low oil prices, both in terms of how much they fell and how long they persisted in being lower, caused production in some parts of the world to decline. In the United States for example, crude oil production in 1999 is expected to average about 270,000 barrels per day less than production in 1998. Smaller declines are expected in Australia and Mexico. The North Sea is estimated to remain relatively flat, as small increases in oil production from the United Kingdom are offset by declines in the Norwegian sector. In 2000, non-OPEC oil production is expected to increase by about 800,000 barrels per day, as higher prices enable more oil production to come back into the market. U.S. oil supply in 2000 is expected to average about the same as in 1999 but other areas are expected to increase from 1999 levels. For instance, our forecast assumes an increase of about 400,000 barrels per day in North Sea oil supply next year as well as sizeable increases from Mexico and Australia.

International Oil Demand

Figure 11. World Oil Demand (Changes from Previous Year)



World oil demand is expected to continue to increase through 2000 (Figure 11), by which time total world oil demand may average over 76 million barrels per day (Table 3). With problems in several Southeast Asian countries softening the increase in world oil demand in 1998, world oil demand increases in 1999 and 2000, while larger than in 1998, are forecasted to be less than the increases seen before the Asian economic problems began. Following an annual world oil demand increment of 1.7 million barrels per day in 1997, world oil demand is estimated to have increased by nearly 0.8 million barrels per day in 1998, and 1999 world oil demand is expected to increase by only 1.1 million barrels per day. In 2000, world oil demand is forecasted to increase by over 1.3 million barrels per day, as Asian oil demand is expected to recover somewhat. However, higher oil prices are expected to dampen world oil demand increases in 2000. But, with less demand in Southeast Asia than expected prior to the economic crisis, world oil demand under these assumptions will be growing at an average annual rate of 1.4 percent between 1997-2000 after growing at an average annual rate of 2.2 percent between 1994-1997.

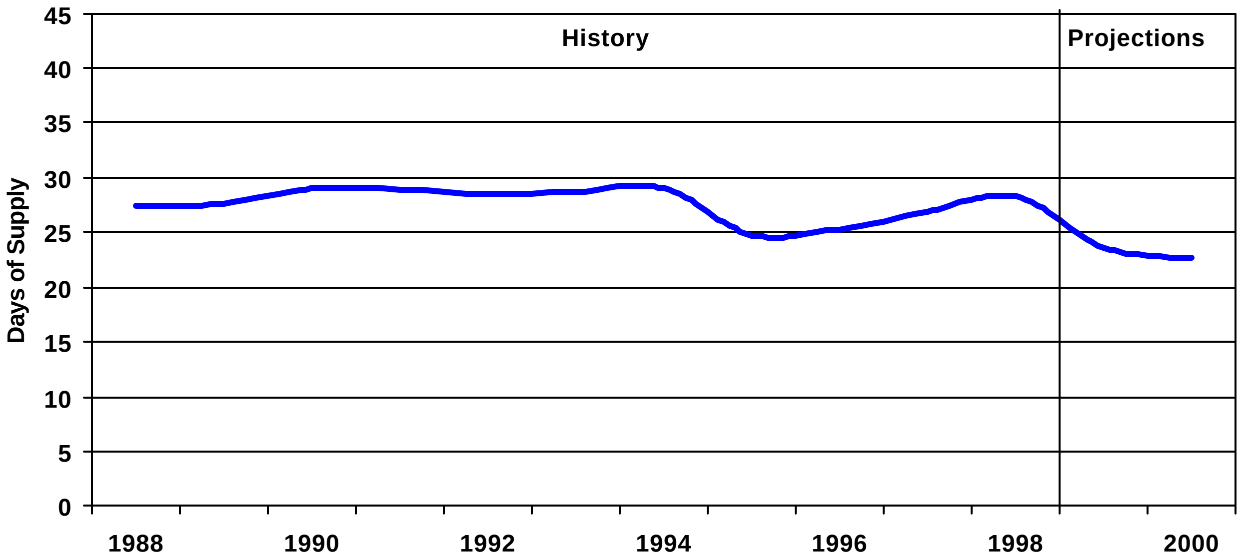
After increasing by about 400,000 barrels per day in 1998, oil demand in countries of the OECD is expected to increase by nearly 700,000 barrels per day in 1999 but only about 400,000 barrels per day in 2000, an average annual rate of 1.3 percent (Figure 11 and Table 3). (Our OECD estimates do not yet include those of the Czech Republic, Hungary, Mexico, Poland, and South Korea). Japan's current recession is the main reason for a decline of about 200,000 barrels per day in Japanese oil demand in 1998, and oil demand in Japan should remain relatively flat in 1999. An increase of over 100,000 barrels per day in Japanese oil demand is expected in 2000. Partly because of the general weakness expected for Japanese demand, the United States' oil demand growth represents over half of OECD oil demand growth in 1999, but is minimal in 2000, as U.S. oil demand remains relatively flat due to higher oil prices.

A major story regarding world oil demand continues to be the effect the economic problems in Southeast Asia are expected to have on oil demand growth in the region. Prior to this recent economic slowdown, non-OECD countries exhibited strong growth in oil demand. This was especially true in Asian countries. For example, oil demand in China and in Other Asia (see Summary of Important Terms for definition) grew by about 7.5 percent per year between 1991-1997. However, due to the recent economic slowdown in several Asian countries, this forecast has an average annual oil demand growth rate of 4.8 percent for China and a growth of only 2.8 percent for Other Asian oil demand between 1998 and 2000. At the same time, Latin American oil demand is expected to grow at an annual rate of only 1.4 percent between 1998 and 2000.

After showing some growth in 1997 for the first time since the collapse of the Soviet Union, oil demand in the former Soviet Union (FSU) is estimated to have declined slightly in 1998. As economic problems in Russia continue to mount, oil demand in the FSU is expected to continue to decline in 1999, before increasing slightly in 2000. Oil demand in the FSU, which was 8.7 million barrels per day just 10 years ago, is forecasted to be about 4.2 million barrels per day in 2000 (Table 3).

World Oil Stocks, Capacity and Net Trade

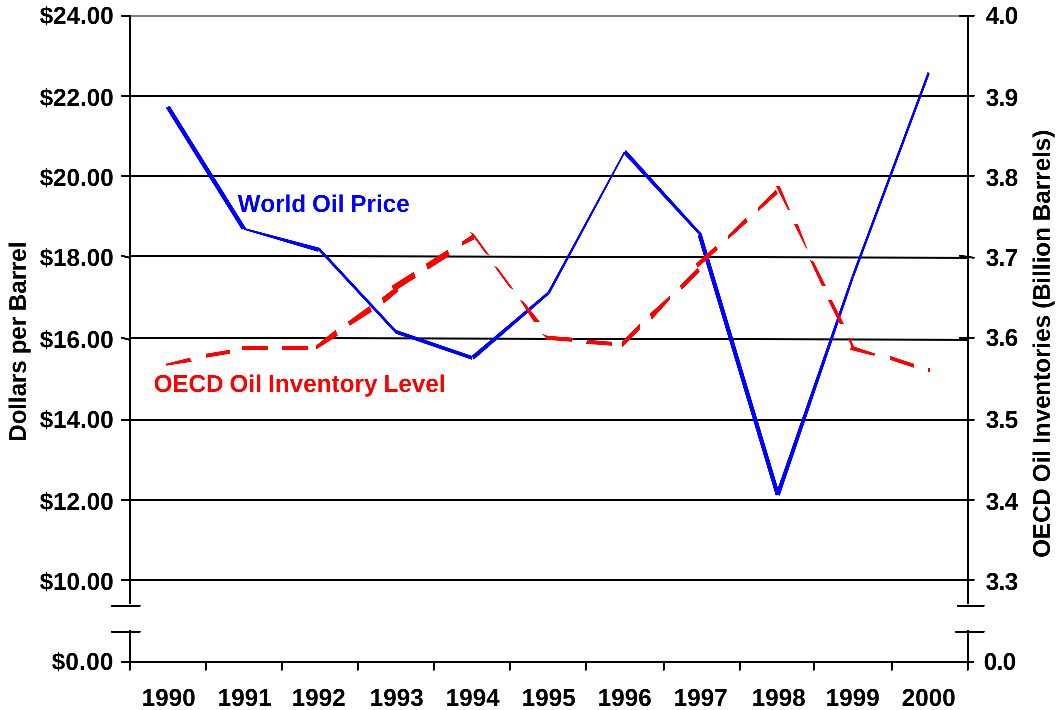
Figure 12. OECD Commercial Oil Stocks



Commercial oil inventories (measured in days of supply) in OECD countries increased by nearly 3 days worth in 1997 and 1998 combined, the largest such 2-year increase since at least 1982. OECD commercial oil inventories are expected to decrease in 1999 by about 4.6 days of supply and by another 1.0 days of supply next year to end 2000 at levels not seen in recent years (Figure 12). The decrease in 1999 and 2000 is in large part due to OPEC and non-OPEC cuts in oil production. The inverse relationship between stock levels and the direction in prices continues, as prices are projected to rise while inventories fall (Figure 13).

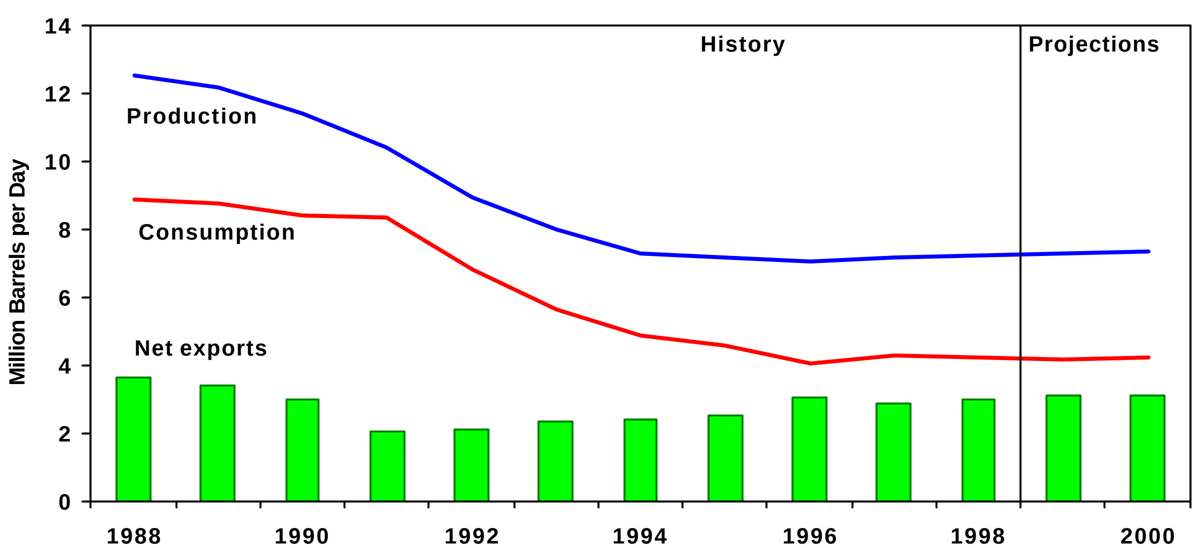
OPEC oil production capacity is expected to increase by 1.5 million barrels per day between 1998 and 2000. Overall, OPEC excess oil production capacity is expected to increase from about 3.1 million barrels per day in 1997 to about 5.8 million barrels per day in 1999 (as cuts in OPEC production are not matched by cuts in capacity). This level would be the highest it's been since 1988. A resumption of production increases next year should reduce excess capacity to 5.1 million barrels per day in 2000. Saudi Arabia is expected to control nearly half of OPEC excess production capacity and, along with Kuwait and the United Arab Emirates, control over 60 percent of excess oil production capacity in the world.

Figure 13. OECD Oil Stocks vs. World Oil Price, 1990-2000



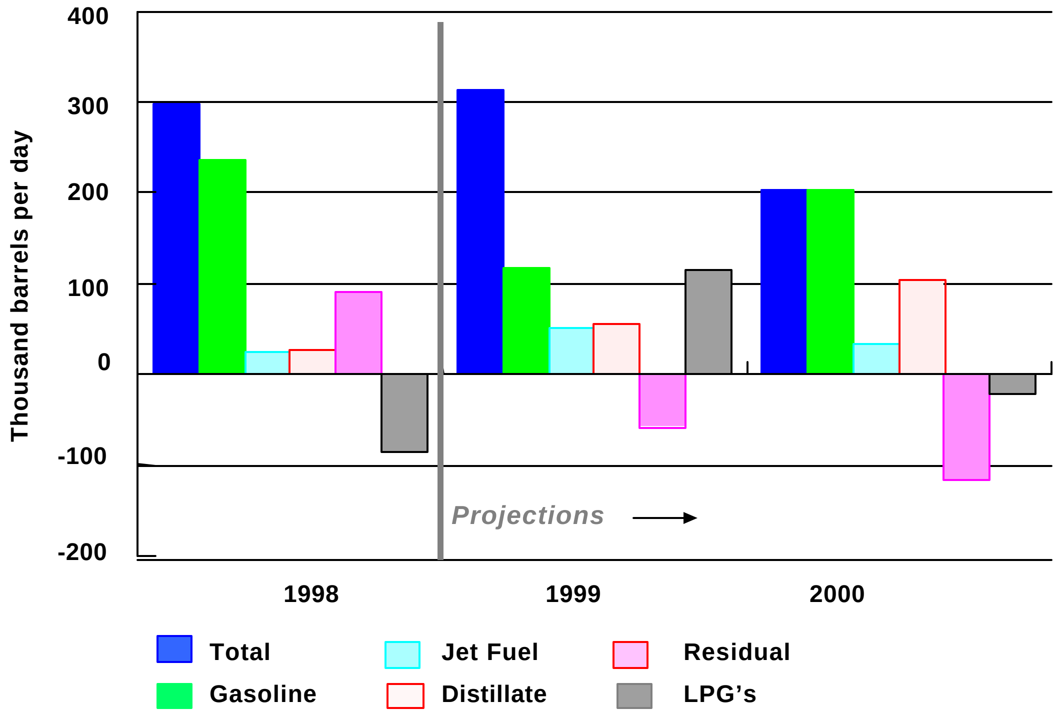
Net exports from the FSU are expected to increase slightly during the forecast period, from 2.9 million barrels per day in 1997 to about 3.1 million barrels per day in 2000 (Figure 14). Exports are significantly higher than they were immediately following the collapse of the FSU (2.1 million barrels per day in 1991 and 1992) and are at levels not seen since before the collapse of the Soviet Union (3.0 million barrels per day in 1990).

Figure 14. FSU Oil Production, Consumption and Net Exports



U.S. Oil Demand

Figure 15. Petroleum Demand Growth (Change from Year Ago)

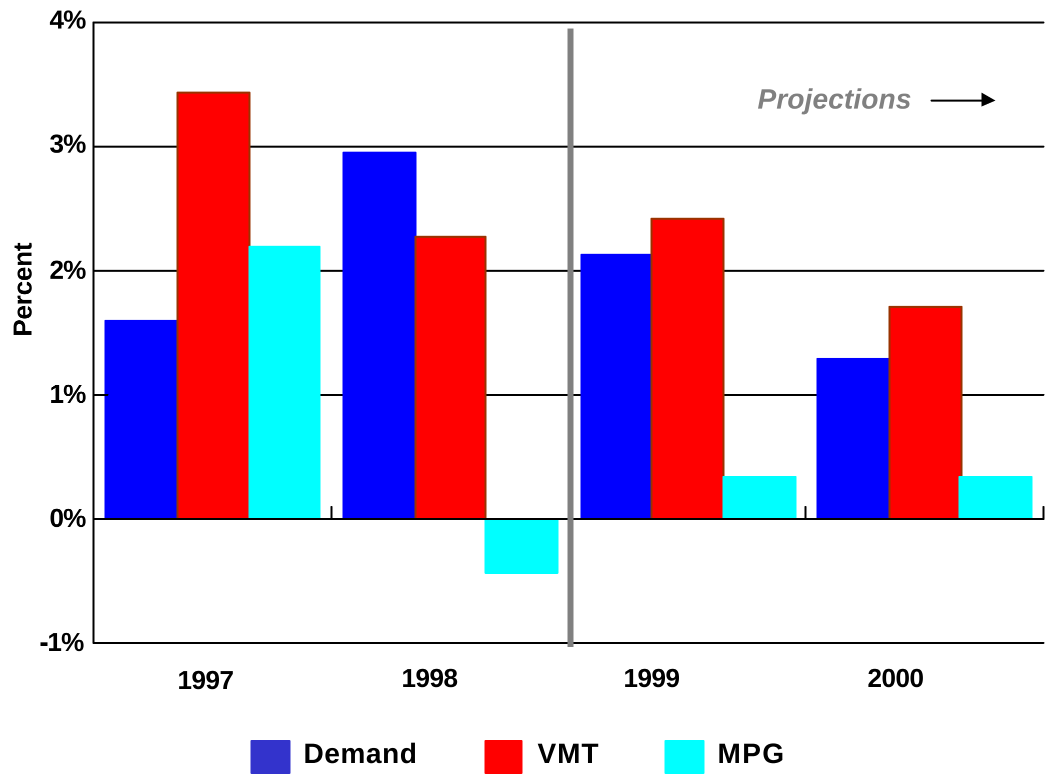


For the first nine months of 1999, growth in petroleum demand averaged 1.8 percent compared to demand during the same period in 1998. That increase was broad-based, with transportation demand accounting for much of that growth. Data for that period, however, indicate an ongoing decline in residual fuel oil demand in the wake of substantial increases in oil prices. Nonetheless, petroleum demand is projected to increase by 360,000 barrels per day, or 1.9 percent, for 1999, somewhat higher than the growth rates of the preceding two years, assuming continued economic growth and normal weather patterns (Figure 15). In 2000, total petroleum demand is projected grow by only 30,000 barrels per day, or 0.2 percent. The projected growth in both real gross domestic product and manufacturing activity is projected to be only about half that of the current year, and higher oil prices are expected to result in growing fuel substitution in price-competitive sectors.

Motor gasoline demand is expected to continue its upward climb throughout the forecast interval (Figure 16), but the increase is expected to taper off in response to the slowdown in economic growth as well as the lagged effect of increased retail gasoline prices. Continued high levels of consumer confidence and robust growth in disposable income, however, boosted increases in summer driving by 2.5 percent despite a 11-percent increase in retail motor gasoline prices from those of last summer. For the current year as a whole, motor gasoline growth is expected to be 2.1 percent, and growth in highway travel is expected to be 2.4

percent. In 2000, motor gasoline demand growth is expected to slow to only 1.3 percent, in response to a 1.7-percent increase in projected highway travel growth. Part of the slowdown is the projected 13-percent increase in average retail prices. But a continuation of a tendency of highway travel growth to lag that of disposable income is also expected to account for the slowdown in the growth of gasoline demand. 1999 and 2000 are projected to be the third and fourth consecutive years in which growth in highway travel is expected to trail that of real disposable income, representing a reversal of a pattern in which highway travel growth had exceeded that of disposable income.

Figure 16. Year to Year Changes in the Gasoline Market



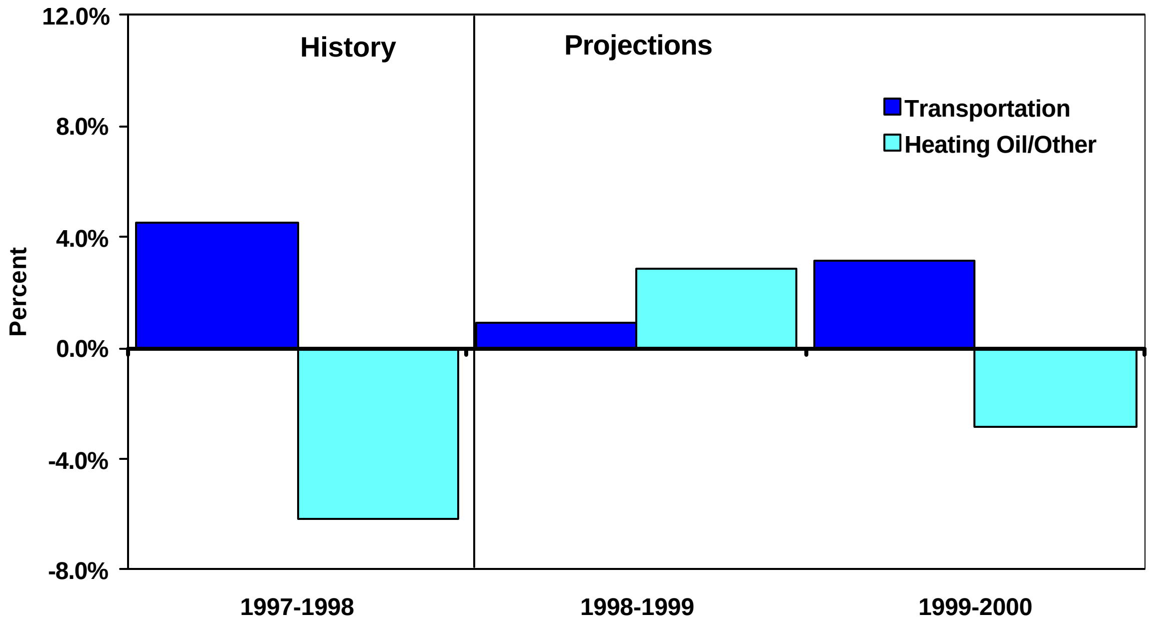
In jet fuel markets, last year saw weak demand brought about by economic slides in key emerging markets. For the year, commercial jet fuel demand and revenue ton-miles rose only 1.8 percent. Capacity rose more robustly, at 3.8 percent. During the latter half of the year, revenue ton-miles actually declined. During that interval, capacity continued to increase (albeit at a slower pace), allowing for slight increases in commercial jet fuel demand in the face of continued increases in fuel efficiencies and declining load factors. Available data suggest a brisk recovery in commercial jet fuel demand in 1999. For the first half of 1999, it grew at more than 4 percent compared to the same period in the previous year, buoyed by a 5-percent increase in capacity. Revenue ton-miles continued to recover, increasing by 4 percent. For the year as a whole, commercial jet fuel demand is projected to climb 3.6 percent. Total jet fuel demand (including military and other uses) is projected to increase 3.1 percent. In 2000, commercial jet fuel demand is projected to climb 1.3 percent, reflecting continued increases in fuel efficiencies brought about by the deployment of new aircraft as well as a slowdown in capacity growth. Military use, however, is expected to climb briskly, bringing projected total jet fuel demand growth to 2.3 percent for the year.

Distillate demand growth for 1998 was very weak, estimated to be 0.8 percent, compared to growth of 2.1 percent in 1997 (Figure 17). Much of that slowdown was brought about by two factors: a moderation in manufacturing output growth from 6.7 percent in 1997 to 4.2 percent for 1998 and (most importantly) the combined effects of warmer weather in the first and fourth quarters. Total distillate demand is projected to increase by 1.6 percent in 1999 and a further 1.1 percent in 2000. This growth results largely from continued but more moderate growth in transportation (diesel) and industrial demand. The assumed return to normal weather patterns for the 1999-2000 winter season is unlikely to offset continued erosion of heating oil demand in the residential and commercial sectors.

Residual fuel oil demand in 1998 staged a recovery from all-time lows, increasing by 11 percent. That increase was brought about by prior declines in residual fuel prices of between 20 and 30 percent in the price-sensitive electricity generation sector. Electric utility consumption of heavy fuel oil increased by an estimated 130,000 barrels per day, or 42 percent, with year-over-year growth rates ranging as high as 100 percent or more for some months. Other sectors, however, experienced demand weakness in 1998. Transportation deliveries of residual fuel oil (bunker fuel) shrank as refinery upgrades reduced the availability of the fuel. Abnormally warm weather during the first and fourth quarters resulted in a decline in deliveries to weather-sensitive sectors.

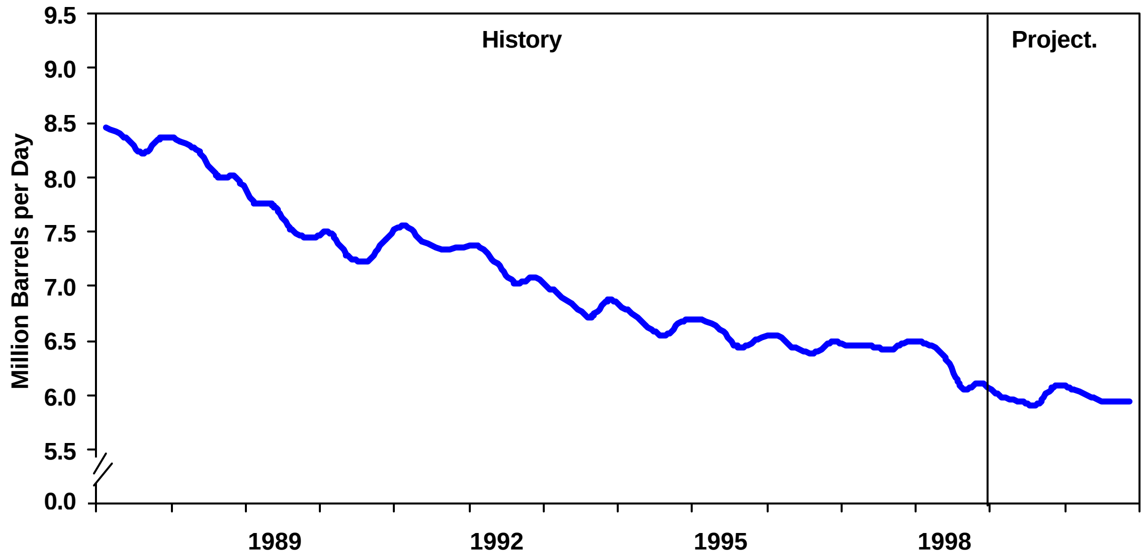
In 1999, however, total residual fuel oil demand is projected to decline 5 percent and by 18 percent in 2000. Most of that decline stems from a decline in electric utility consumption. Despite a return to normal weather patterns, utilities' demand is expected to decline by 13 percent this year and by a further 32 percent in 2000 due to substantial increases in relative prices of residual fuel oil that are expected to induce a shift to other fossil fuels.

Figure 17. Distillate Demand Growth (Percent Change from Year Ago)



U.S. Oil Supply

Figure 18. U.S. Crude Oil Production



The sharp decline in oil prices that began in 1997 and ended this past winter has taken its toll on U.S. oil production. Although prices rebounded dramatically this year, domestic crude oil production has remained flat during the first 6 months of 1999. The rapid decline in production lowered 1998 average domestic crude oil production to 6.25 million barrels per day, a decline of 3.1 percent from production in 1997 (Figure 18). A further decline of 4.2 percent is expected in 1999, followed by a slowdown in the decline rate to 0.3 percent in 2000.

Lower-48 States oil production is expected to decrease by 140,000 barrels per day in 1999, followed by an increase of 70,000 barrels per day in 2000. Oil production from the Ram-Powell, Auger, Ursa, Mars, Troika, Baldpate, and Diana-Hoover Federal Offshore fields is expected to account for about 11.5 percent of the lower-48 oil production by the 4th quarter of 2000. Shell's Auger platform was cut back to 70,000 barrels per day in the fourth quarter of 1998. After additional gas treatment facilities are installed, production should increase to 100,000 barrels per day in the third quarter of 1999. Shell has started production in 1999 in their Ursa field which will peak in the year 2000 at 150,000 barrels per day of condensate. Shell also estimates that the Mars platform has increased by another 40,000 barrels per day in 1999. The Baldplate Platform started production in August 1998 and Amerada Hess estimates a production rate of 50,000 barrels per day in the first quarter of 1999. Exxon's Diana and Hoover fields should start production in mid 2000 at a rate of 30,000 barrels per day, increasing to 100,000 barrels per day in early 2001.

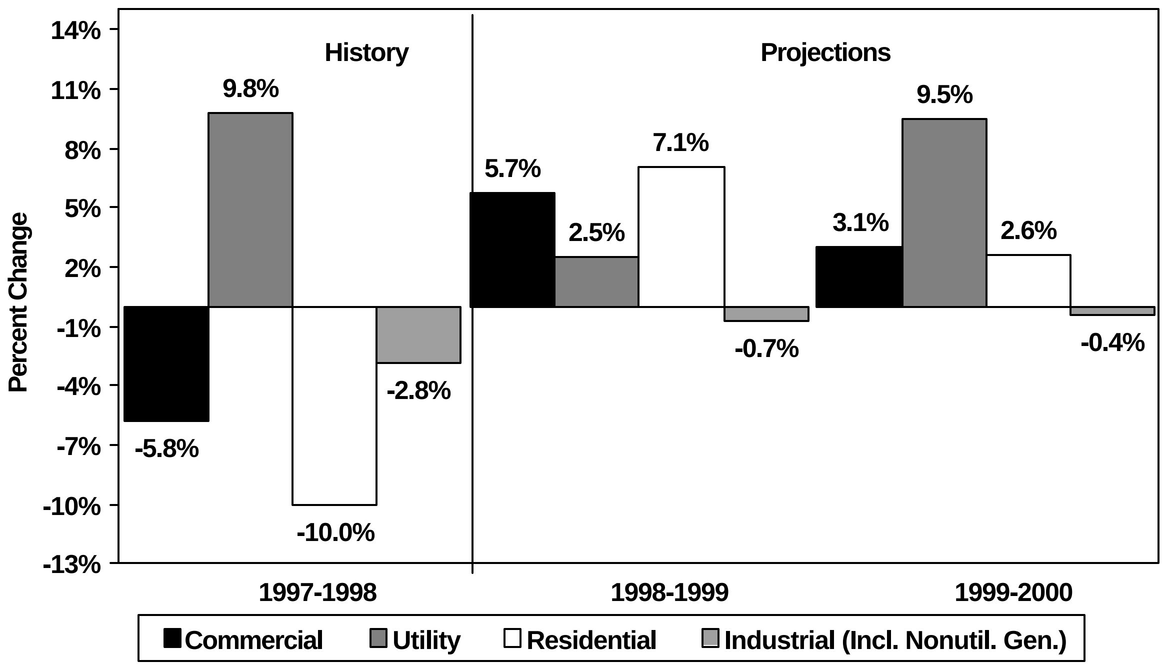
Alaska is expected to account for about 16 percent of total U.S. oil production in 2000. Production there is expected to decrease by 100,000 barrels per day (8.3

percent) in 1999, followed by a further decline of 120,000 barrels per day in 2000 (10.7 percent).

Almost 52 percent of total U.S. petroleum demand was met by net imports of crude oil and finished petroleum products in 1998. That percentage is expected to decline slightly in 1999 because of the drawdown of domestic inventories. Import dependence is then expected to increase to 52.6 percent in 2000.

U.S. Natural Gas Demand

Figure 19. Changes in Natural Gas Demand by Sector



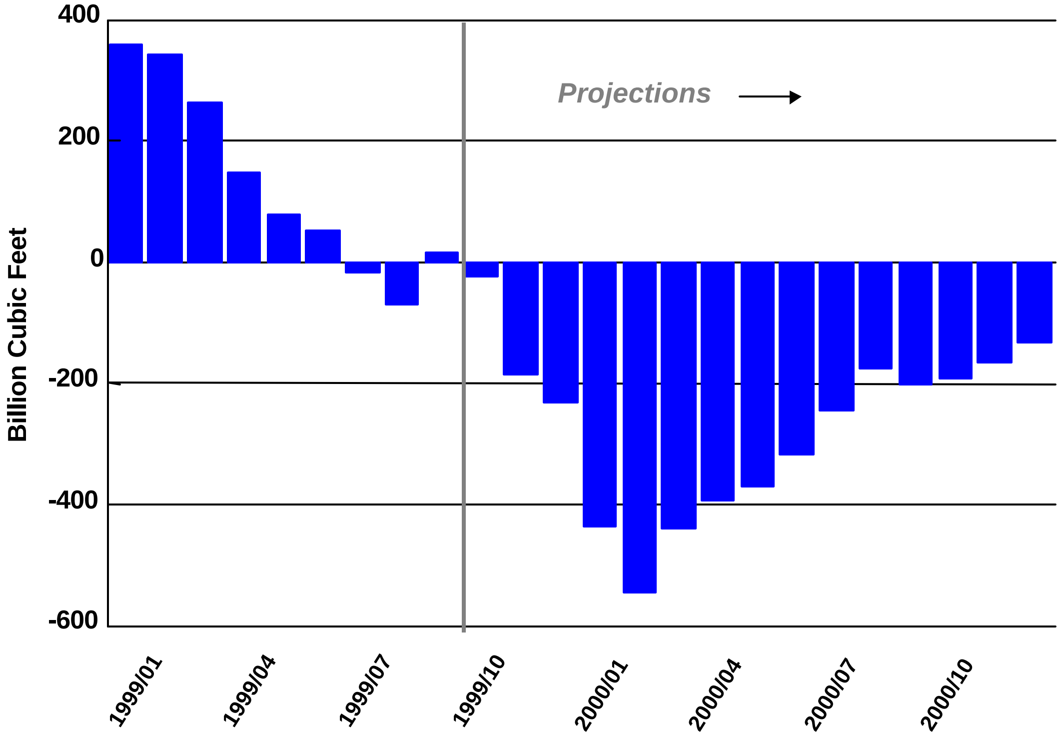
Natural gas demand is expected to increase by 2.4 percent and 2.3 percent, respectively, to 21.86 trillion cubic feet in 1999 and 22.37 in 2000. These increases follow the negative growth seen in 1998, when oil prices were lower than natural gas prices in the electricity and industrial sectors. In 1999 and in 2000, with the price of oil rising, natural gas prices are expected to be more competitive.

The increase in natural gas demand is expected to be across all sectors, with the exception of the industrial sector in 1999 (Figure 19), which is expected to be down by 0.7 percent from its relatively high 1998 level. The assumption of normal weather for the forecast period, and in particular the increase in heating degree-days this winter, is the primary reason for the increase in natural gas demand. Total residential demand for gas is expected to rise by 7.1 percent in 1999 and by another 2.6 percent in 2000. However, in the coming winter alone, residential demand for natural gas is expected to be up by 10.2 percent.

Likewise, commercial natural gas demand this winter is expected to rise by 12.3 percent, and electric utility gas demand by 8.7 percent.

U.S. Natural Gas Supply

Figure 20. Changes in Total Gas Underground Storage (From Year Ago)



Dry gas production is expected to remain close to our previously projected levels through the forecast period. Dry gas production is expected to dip somewhat in 1999 from 1998 levels to 18.69 trillion cubic feet, but rise in 2000 to 18.97 trillion cubic feet, somewhat above the 1998 level. This expectation is based on data reported to EIA by the producing states through April 1999 and projected outward through the forecast period. Of the five major natural gas producing states, four show upward production trends. Rising gas prices and rig counts help to support our projections.

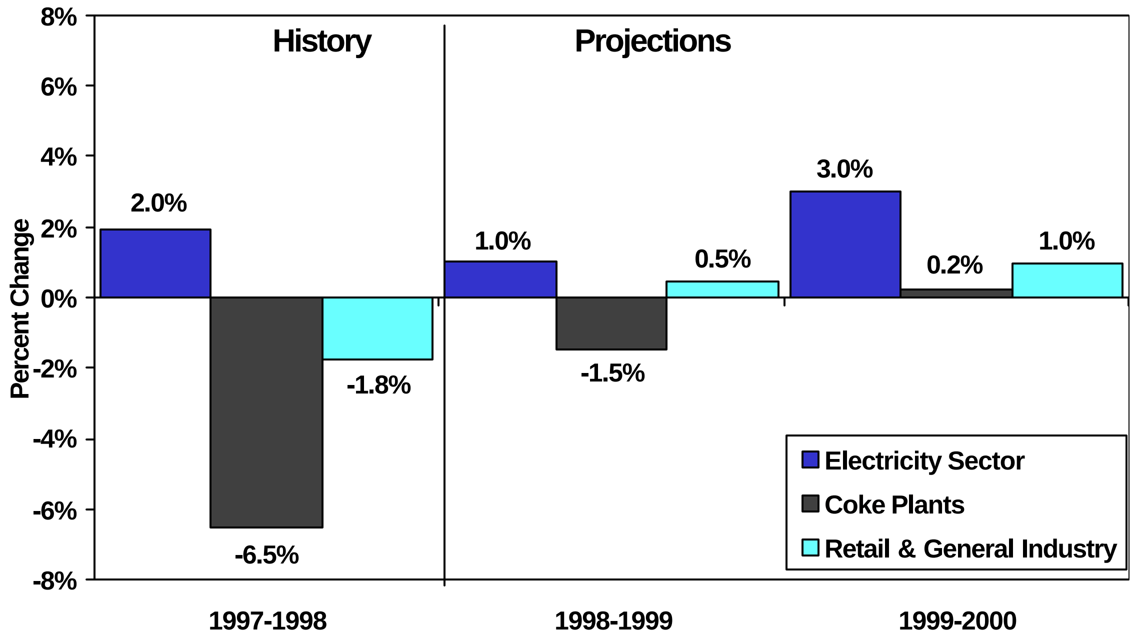
Natural gas net imports for 1999 and 2000 are expected to be at 3.33 trillion cubic feet in 1999 and at 3.60 trillion cubic feet in 2000. Additional pipeline import capacity from Canada as well as increasing demand for natural gas are the reasons. However, the ability of Canadian producers to fill the new pipelines will depend on storage and drilling levels in Canada.

Gas storage levels, which were generally above year-earlier levels for much of 1999, fell below comparable 1998 levels in July and August, as expected, due to high cooling demand. Our analysis indicates that storage levels in September were about equal to the relatively high levels of one year ago. Storage is expected to be somewhat lower than the abnormally high year-ago levels by the end of the fourth quarter 1999 if normal heating demand develops, and to continue to be below year-ago levels through 2000 (Figure 20). End-of-October working gas storage levels have averaged 2,987 billion cubic feet for the past 5 years (1994-1998). The 1998 end-of-October level, which reached 3,176 billion cubic feet, was the highest storage level since 1992.

The natural gas rig count for September was 565, and has been rising steadily since the low of 371 in April, as oil and gas prices have risen.

U.S. Coal Demand and Supply

Figure 21. Annual Change in U.S. Coal Demand



Total coal demand is expected to increase by 1.0 percent in 1999 and by 2.8 percent in 2000, compared to 1.3 percent growth in 1998 (Table 9 and Figure 21). Electric utility coal demand is expected to fall in 1999 by 0.7 percent but increase by 2.4 percent in 2000. The fall in electric utility coal consumption is an artifact of the sale of coal-fired generation facilities to non-utilities, a result of the restructuring of the electric power industry. If the estimated coal consumption of these recently sold plants is taken into account, the consumption of coal by "utility" plants is projected to increase by 1.2 percent. The electricity sector (utility and non-utility generators) currently consumes 90 percent of all coal used in the United States.

Coal carbonized (consumed) by coke plants is expected to fall by 1.5 percent in 1999 to 27.8 million short tons. Demand for coal at coke plants is expected to remain below 28 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 76.1 million short tons in 1999, a 0.5 percent increase over 1998 demand. In 2000, demand is expected to increase by 1.0 percent from the 1999 level.

U.S. coal exports are expected to continue to weaken as the lower-priced coals from Australia and South Africa, as well as the growing coal export industries of

Indonesia, Venezuela, and Colombia, grab a larger share of the market. While steam coal exports are down sharply, the decline in metallurgical coal exports is larger and has the potential to affect exports over the long term. The collapse of metallurgical coal prices in the Asian market was reflected worldwide and was even steep enough to overcome the historically perceived premium quality of U.S. metallurgical coals. These events led to the closure of several mines and could possibly represent a permanent loss of market share for the United States. Exports are projected to be 62.1 million short tons in 1999 (a 20.4 percent decrease) and 62.7 million short tons in 2000 (Table 9).

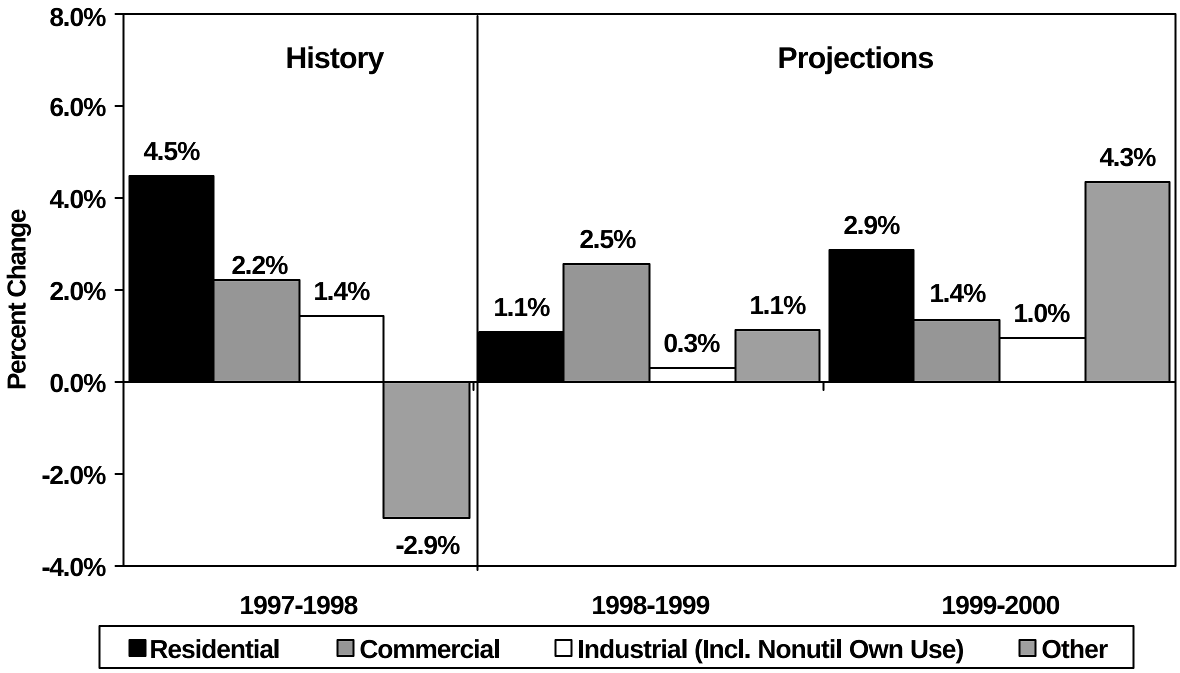
Coal imports grew 16.5 percent in 1998, but they represent less than 1 percent of total U.S. consumption. The continued strength of the dollar, coupled with increased demands for low sulfur compliance coal and the impending CAAA (Clean Air Act Amendments) Phase II emission requirements, will provide the impetus for continued growth of coal imports. Imports are forecast to be 8.9 million short tons in 1999 (a 1.7 percent increase) and to grow 15.2 percent to 10.2 million short tons in 2000.

Following the record 1,118.1 million short tons of coal that were produced in 1998, production is expected to fall somewhat in 1999. Mild weather over much of the country during last fall and winter reduced coal use at electric utilities and led to a large buildup in coal stocks. A significant portion of the electric utility coal requirements for 1999 will be met by drawing down these stockpiles. As a result, the need for growth in coal production will be weak. Annual output is expected to reach 1,109.6 million short tons in 1999. Production will grow 1.8 percent in 2000 to 1129.1 million short tons. Production in the Western region should continue to grow over the forecast period (0.4 percent in 1999 and 4.8 percent in 2000) as Phase II emission requirements lead many utilities to switch to low sulfur coal, primarily produced from the Powder River Basin. The Western region became the nation’s largest coal producer in 1998, surpassing the Appalachian region. Production in the Appalachian region is projected to be essentially flat during the forecast period. The loss of export markets will hurt production in the region and high-sulfur mines will start to decline in response to the coming Phase II emission standards. The Interior region will likewise be hurt by the loss of a market for high-sulfur coal. Production in this region is projected to decline 5.4 percent in 1999 and 2.8 percent in 2000.

Total coal stocks (producers and consumers) were 165.6 million short tons at the end of 1998, a 17.9 percent increase from the stocks of the previous year. Producer stocks rose by 6.4 percent in 1998, and they are expected to fall by 4.9 percent in 1999. Consumer stocks will continue to build in 1999 (by 11.0 percent) and in 2000 (by 4.4 percent).

U.S. Electricity Demand and Supply

Figure 22. Changes in U. S. Electricity Demand



Assuming normal weather for the remainder of the forecast, the outlook for electricity demand in 1999 is a modest growth of 1.2 percent. In 2000, electricity demand is expected to grow by 1.8 percent. Average electricity growth between 1990 and 1998 was about 2.0 percent per year.

Heating degree-days this winter are expected to be 8.0 percent higher than those of last winter, which was quite mild. Thus, a 3.4 percent increase in electricity demand is indicated for this winter compared to last winter's demand. The increase in summer demand in 1999 for electricity (April through September), despite the July/August heat wave, was only about 0.5 percent, as cooling degree-days overall were 8.0 percent below normal.

Demand for electricity is seen as growing across all sectors, led by the residential and commercial sectors (Figure 22). However, industrial electricity demand in 1999 is expected to be close to 1998 levels and to grow at about 1 percent in 2000.

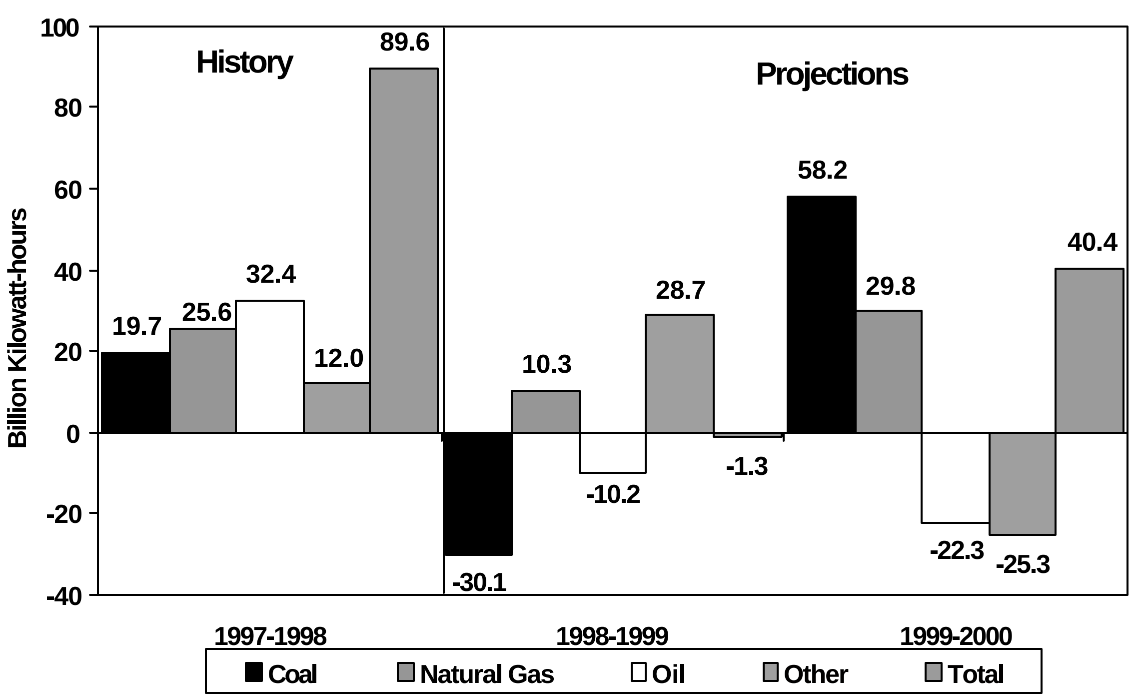
The fuel mix at electric utilities has changed significantly from what it was last year (Figure 23). In particular, gas-fired electricity generation is expected to increase significantly from 1998 levels in both 1999 and 2000, while oil, coal and hydro powered generation decrease. This is due to the increases in world petroleum prices; coal-fired plant sales to non-utilities under restructuring, and lower water levels in the Pacific Northwest than there were during the 1997 high.

Nuclear power generation is expected to rise significantly in 1999, as some plants that were down have come back online. In 2000, nuclear power generation is expected to be below the 1999 level but still remain well above what it was in 1998.

Net imports of electricity fell through most of 1998 and are expected to continue to fall in 1999, in spite of some positive movements in mid-summer. This is due to the shutdown of certain Canadian nuclear plants in the first quarter. Although the next two quarters approached normal output, the total year will end up 6.3 percent below the 1998 level. In 2000, net electricity imports are expected to be positive, rising by 1.5 percent from what they were in 1999.

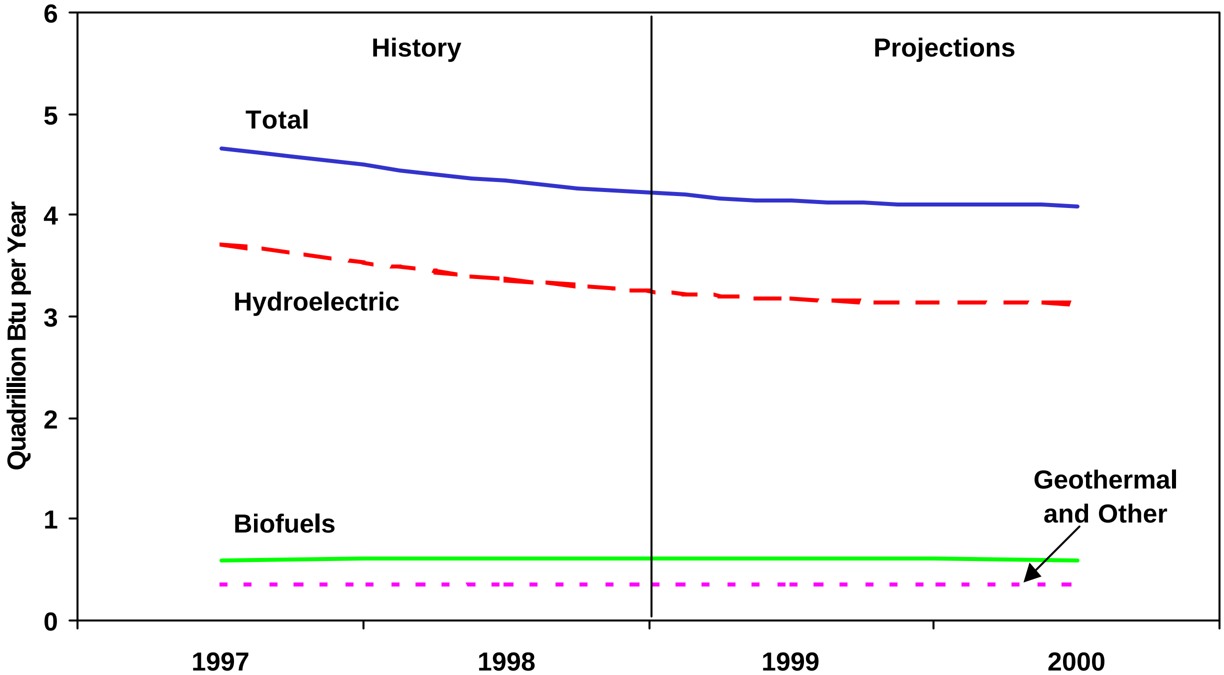
U.S. electricity generation by non-utilities in 1999 is expected to increase by almost 17 percent and sales of non-utility electricity to utilities is expected to increase by almost 30 percent. The increase is the result of state restructuring of electricity generating units and utility divesting of their generating units. Non-utility generation is expected to continue to increase in 2000, although more slowly than in 1999. The reason for the slowdown is due to the fact that we have not assumed any additional divestment of electric plants to independent status from the electric utility sector. In 2000, non-utility sales of electricity to utilities are expected to continue to rise but more slowly than in 1999 at about 6 percent. Again, this pattern reflects divestment activity in 1998 and 1999 and our assumptions about no additional activity in 2000.

Figure 23. Year-to-Year Changes in Electric Utility Generation by Fuel



U.S. Renewable Energy Demand

Figure 24. Renewable Energy Use for Electricity



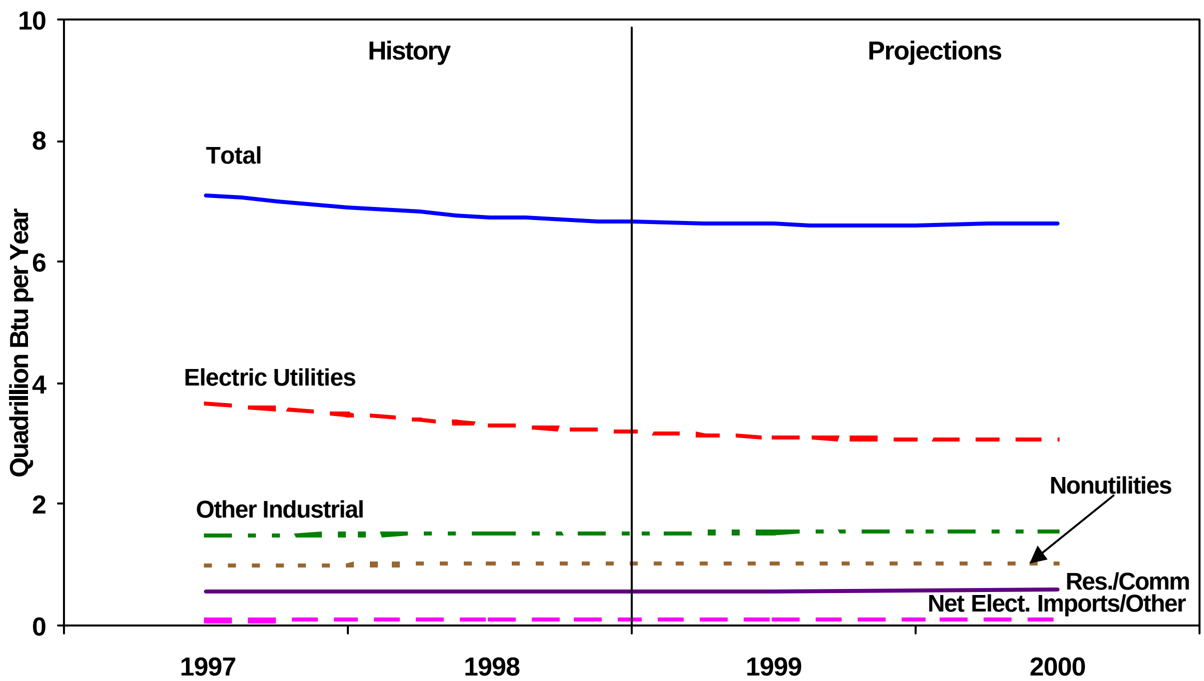
Total renewable energy demand, as defined here, includes minor non-marketed components (that is, amounts which are neither bought nor sold, either directly or indirectly, as inputs to marketed energy). The Energy Information Administration does not estimate or project total consumption of non-marketed renewable energy.

Renewable energy use in the United States in 1998 amounted to about 6.7 quadrillion Btu (quads), or about 7.1 percent of total domestic gross energy demand (Tables HL1 and 11). In 1998, use of renewables is estimated to have decreased by about 4.5 percent due mainly to a decline in hydroelectric generation. In 1999, renewables use is expected to decrease by another 0.2 percent (Figure 24), and in 2000, renewables use is expected fall by an additional 1.2 percent.

More than half of all renewable energy use measured by EIA is associated with the production of electricity. While the biggest component of electricity producers' use of renewables is hydroelectric power generated by electric utilities (Figure 25), a significant and growing portion of renewables use occurs at nonutility generating facilities. In the electric utility sector, geothermal generation drops dramatically in 1999 and in 2000, while it rises significantly in the non-utility sector. This is due to sales of geothermal plants by utilities to non-utilities, as a result of electricity restructuring.

Most of the nonutility use of renewables involves biofuels, principally wood and wood by-products.

Figure 25. Renewable Energy Use by Sector

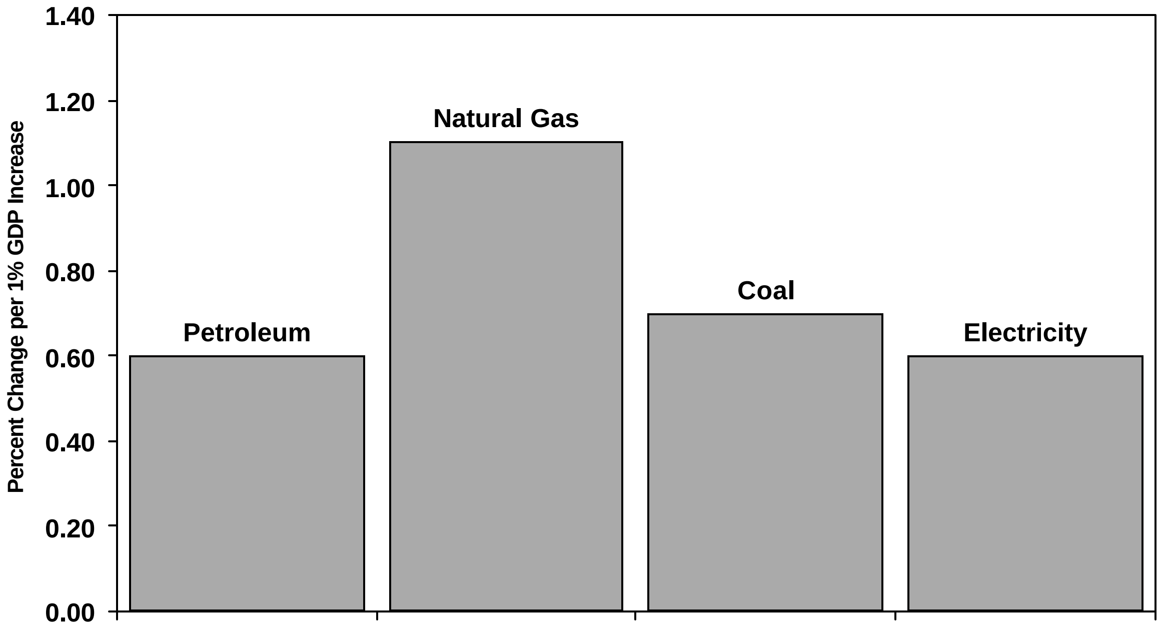


Currently, aside from power generation, the most significant area of renewables use is in the industrial sector, accounting for 22 percent of the total in 1998. This component consists principally of biofuels.

Renewables use in the combined residential and commercial sector, at about 0.6 quadrillion Btu in 1998, generally accounts for about 8 percent of total domestic renewables demand (Table 11). Most of this energy is wood used for home heating, with only a very small amount having to do with solar hot water heating.

U.S. Energy Demand and Supply Sensitivities

Figure 26. Macro Sensitivities



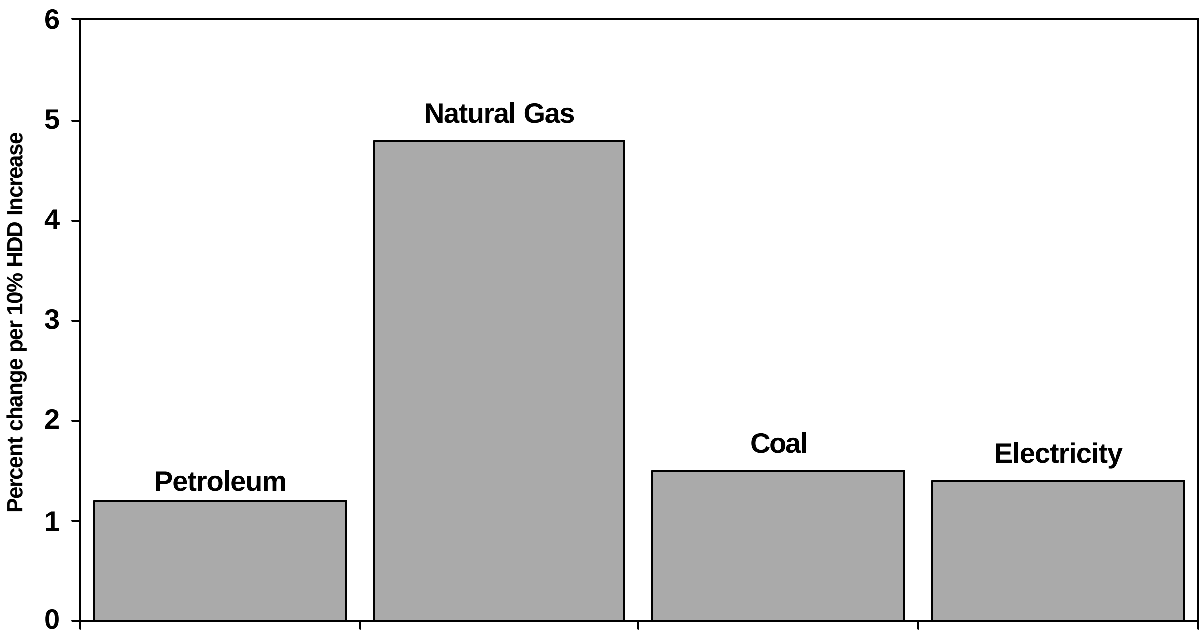
The petroleum demand and supply outlook for the mid-price case is based on assumed normal temperatures and GDP growth of 3.8 percent per year in 1999 and 2.2 percent in 2000. To enhance the usefulness of the mid-case forecasts, sensitivities of energy demand and supply are also derived by using alternative macroeconomic, price, and weather assumptions. Plausible macroeconomic and weather-related petroleum demand sensitivities are illustrated in Figures 26 and 27 and Table 6.

A 1 percent increase in real GDP raises petroleum demand by about 0.6 percent; natural gas demand by 1.1 percent; coal demand by 0.7 percent; and electricity demand by 0.6 percent (Figure 26). The impact of shifts in economic growth varies, depending upon distribution of incremental growth across energy-intensive and non-energy-intensive sectors.

A 10 percent increase in crude oil prices, assuming no price response from non-petroleum energy sources, reduces petroleum demand by 0.3 percent. A 10 percent increase in gas prices at the wellhead, assuming no price response for other fuels, reduces natural gas demand by 0.4 percent.

A 10 percent increase in heating degree-days increases winter petroleum demand by 1.1 percent; natural gas demand by 4.4 percent; coal demand by 1.7 percent; and electricity demand by 1.5 percent (Figure 27). The impact of heating degree-day deviations from normal may not be symmetrical. Extremely cold weather could result in indirect effects on fuel oil markets due to potential natural gas supply constraints.

Figure 27. Weather Sensitivities



A 10 percent increase in cooling degree-days increases summer petroleum demand by about 0.1 percent, natural gas by 1.0 percent, coal by 1.7 percent and electricity demand by 1.7 percent.

A $1-per-barrel increase in crude oil prices boosts domestic oil supply (crude oil and natural gas liquids production) by about 103,000 barrels per day.

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.

NATURAL GAS

Natural gas wellhead price: The wellhead price of natural gas, which is 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.

Natural gas spot price: 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 1992.

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.

Table 1. U.S. Macroeconomic and Weather Assumptions

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Macroeconomic [a]															
Real Gross Domestic Product															
(billion chained 1992 dollars - SAAR).........	**7465**	**7499**	**7566**	**7678**	**7760**	**7794**	*7865*	*7929*	*7934*	*7971*	*8037*	*8107*	**7552**	*7837*	*8012*
Percentage Change from Prior Year	**4.2**	**3.6**	**3.5**	**4.3**	**4.0**	**3.9**	*3.9*	*3.3*	*2.2*	*2.3*	*2.2*	*2.2*	**3.9**	*3.8*	*2.2*
Annualized Percent Change															
from Prior Quarter......................................	**5.4**	**1.8**	**3.6**	**5.9**	**4.3**	**1.8**	*3.6*	*3.2*	*0.3*	*1.9*	*3.3*	*3.5*			
GDP Implicit Price Deflator															
(Index, 1992=1.000)	**1.123**	**1.126**	**1.129**	**1.131**	**1.135**	**1.140**	*1.143*	*1.147*	*1.153*	*1.156*	*1.160*	*1.165*	**1.127**	*1.141*	*1.158*
Percentage Change from Prior Year	**1.2**	**1.0**	**1.0**	**0.9**	**1.1**	**1.2**	*1.2*	*1.5*	*1.5*	*1.4*	*1.5*	*1.5*	**1.0**	*1.2*	*1.5*
Real Disposable Personal Income															
(billion chained 1992 Dollars - SAAR)	**5287**	**5322**	**5364**	**5421**	**5468**	**5500**	*5526*	*5542*	*5601*	*5663*	*5699*	*5739*	**5348**	*5509*	*5676*
Percentage Change from Prior Year	**3.0**	**3.0**	**3.2**	**3.5**	**3.4**	**3.4**	*3.0*	*2.2*	*2.4*	*3.0*	*3.1*	*3.5*	**3.2**	*3.0*	*3.0*
Manufacturing Production															
(Index, 1992=1.000)	**1.338**	**1.347**	**1.348**	**1.364**	**1.369**	**1.383**	*1.398*	*1.404*	*1.392*	*1.393*	*1.409*	*1.428*	**1.349**	*1.389*	*1.406*
Percentage Change from Prior Year	**6.0**	**5.0**	**3.1**	**2.5**	**2.3**	**2.7**	*3.7*	*2.9*	*1.6*	*0.7*	*0.8*	*1.7*	**4.1**	*2.9*	*1.2*
OECD Economic Growth (percent) [b]													**3.0**	*2.6*	*2.5*
Weather [c]															
Heating Degree-Days															
U.S..	**1984**	**481**	**42**	**1444**	**2154**	**490**	*93*	*1623*	*2264*	*522*	*85*	*1622*	**3951**	*4360*	*4494*
New England	**2768**	**770**	**104**	**2038**	**3039**	**786**	*150*	*2241*	*3219*	*894*	*167*	*2240*	**5680**	*6216*	*6520*
Middle Atlantic...	**2406**	**570**	**57**	**1779**	**2819**	**629**	*84*	*2005*	*2934*	*709*	*104*	*2004*	**4812**	*5537*	*5751*
U.S. Gas-Weighted.................................	**2087**	**521**	**44**	**1533**	**2275**	**517**	*97*	*1715*	*2378*	*546*	*95*	*1714*	**4185**	*4604*	*4734*
Cooling Degree-Days (U.S.)	**29**	**386**	**903**	**93**	**35**	**354**	*832*	*74*	*31*	*344*	*783*	*74*	**1411**	*1295*	*1233*

[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. Normal is used for the forecast period and is defined as the average number of degree days between 1961 and 1990 for a given period.

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 CONTROL0999.

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

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Macroeconomic [a]															
Real Fixed Investment (billion chained 1992 dollars-SAAR)	**1225**	**1264**	**1271**	**1311**	**1344**	**1377**	*1386*	*1400*	*1412*	*1407*	*1409*	*1427*	**1268**	*1377*	*1414*
Real Exchange Rate (index)	**1.142**	**1.162**	**1.183**	**1.120**	**1.134**	**1.171**	*1.176*	*1.174*	*1.158*	*1.142*	*1.146*	*1.163*	**1.152**	*1.164*	*1.152*
Business Inventory Change (billion chained 1992 dollars-SAAR)	**30.2**	**23.9**	**19.2**	**6.2**	**-3.3**	**-4.3**	*-3.1*	*8.8*	*0.4*	*-2.1*	*0.5*	*5.3*	**19.9**	*-0.5*	*1.0*
Producer Price Index (index, 1982=1.000)	**1.252**	**1.250**	**1.243**	**1.232**	**1.228**	**1.244**	*1.264*	*1.282*	*1.288*	*1.284*	*1.283*	*1.286*	**1.244**	*1.254*	*1.285*
Consumer Price Index (index, 1982-1984=1.000)	**1.621**	**1.628**	**1.635**	**1.642**	**1.648**	**1.662**	*1.674*	*1.690*	*1.703*	*1.710*	*1.718*	*1.727*	**1.631**	*1.668*	*1.715*
Petroleum Product Price Index (index, 1982=1.000)	**0.541**	**0.536**	**0.503**	**0.473**	**0.444**	**0.588**	*0.665*	*0.744*	*0.788*	*0.771*	*0.744*	*0.720*	**0.513**	*0.610*	*0.755*
Non-Farm Employment (millions)	**124.8**	**125.5**	**126.1**	**126.9**	**127.7**	**128.2**	*128.9*	*129.2*	*129.7*	*130.0*	*130.4*	*131.0*	**125.8**	*128.5*	*130.3*
Commercial Employment (millions)	**85.6**	**86.3**	**87.0**	**87.7**	**88.5**	**89.2**	*89.8*	*90.1*	*90.5*	*90.7*	*91.2*	*91.9*	**86.6**	*89.4*	*91.1*
Total Industrial Production (index, 1992=1.000)	**1.303**	**1.312**	**1.316**	**1.323**	**1.327**	**1.339**	*1.354*	*1.361*	*1.352*	*1.356*	*1.371*	*1.387*	**1.314**	*1.345*	*1.367*
Housing Stock (millions)	**113.7**	**114.0**	**114.4**	**115.0**	**115.4**	**115.7**	*116.0*	*116.4*	*116.7*	*117.0*	*117.3*	*117.6*	**114.3**	*115.9*	*117.2*
Miscellaneous															
Gas Weighted Industrial Production (index, 1992=1.000)	**1.175**	**1.171**	**1.158**	**1.156**	**1.169**	**1.169**	*1.178*	*1.183*	*1.174*	*1.175*	*1.185*	*1.196*	**1.165**	*1.175*	*1.182*
Vehicle Miles Traveled [b] (million miles/day)	**6629**	**7424**	**7602**	**7032**	**6712**	**7572**	*7830*	*7265*	*6931*	*7696*	*7869*	*7392*	**7174**	*7348*	*7473*
Vehicle Fuel Efficiency (index, 1997=1.0)	**0.993**	**0.999**	**0.991**	**0.991**	**0.985**	**1.008**	*0.999*	*0.991*	*1.010*	*1.010*	*0.988*	*0.995*	**0.994**	*0.996*	*1.000*
Real Vehicle Fuel Cost (cents per mile)	**3.34**	**3.18**	**3.08**	**3.11**	**2.98**	**3.29**	*3.49*	*3.93*	*3.86*	*3.77*	*3.72*	*3.77*	**3.18**	*3.42*	*3.78*
Air Travel Capacity (mill. available ton-miles/day)	**423.5**	**439.1**	**443.0**	**439.5**	**430.8**	**452.2**	*466.5*	*468.2*	*463.4*	*463.3*	*480.4*	*469.6*	**436.3**	*454.6*	*469.2*
Aircraft Utilization (mill. revenue ton-miles/day)	**237.7**	**259.0**	**260.5**	**247.1**	**242.1**	**263.3**	*276.8*	*261.8*	*254.5*	*271.8*	*287.2*	*272.5*	**251.1**	*261.1*	*271.5*
Airline Ticket Price Index (index, 1982-1984=1.000)	**2.058**	**2.053**	**2.070**	**2.029**	**2.130**	**2.186**	*2.196*	*2.220*	*2.277*	*2.297*	*2.310*	*2.334*	**2.053**	*2.183*	*2.304*
Raw Steel Production (millions tons)	**28.75**	**27.87**	**26.57**	**24.40**	**25.11**	**26.26**	*26.19*	*26.81*	*26.58*	*26.41*	*26.15*	*26.72*	**107.28**	*104.37*	*105.85*

[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 CONTROL0999.

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

(Million Barrels per Day, Except OECD Commercial Stocks)

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Demand [a]															
OECD															
U.S. (50 States)	18.5	18.9	19.2	19.1	19.2	18.9	19.4	19.6	19.0	18.9	19.5	19.8	18.9	19.3	19.3
U.S. Territories	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Canada	1.8	1.8	1.9	1.9	1.9	1.9	2.0	2.0	1.9	1.9	2.0	2.0	1.9	1.9	2.0
Europe	14.9	14.2	14.6	15.2	15.2	14.4	14.8	15.4	15.4	14.4	15.0	15.6	14.7	14.9	15.1
Japan	6.2	5.0	5.2	5.7	6.2	5.0	5.2	5.7	6.3	5.1	5.4	5.8	5.5	5.5	5.6
Australia and New Zealand	0.9	1.0	0.9	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0
Total OECD	42.6	41.0	42.2	43.2	43.7	41.4	42.7	44.0	43.9	41.6	43.1	44.6	42.2	42.9	43.3
Non-OECD															
Former Soviet Union	4.5	4.2	4.2	4.2	4.3	4.0	4.1	4.2	4.4	4.2	4.2	4.2	4.2	4.2	4.2
Europe	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.5	1.5	1.6
China	4.0	3.9	3.9	3.9	4.1	4.1	4.1	4.1	4.3	4.3	4.3	4.3	3.9	4.1	4.3
Other Asia	8.7	8.6	8.6	8.8	8.8	8.8	8.7	9.0	9.2	9.2	8.9	9.3	8.7	8.8	9.1
Other Non-OECD	13.0	13.3	13.4	13.2	13.1	13.4	13.4	13.5	13.4	13.7	13.8	13.7	13.2	13.4	13.7
Total Non-OECD	31.7	31.5	31.4	31.5	32.0	31.8	31.7	32.3	32.9	33.0	32.7	33.1	31.5	32.0	32.9
Total World Demand	74.3	72.5	73.6	74.7	75.7	73.2	74.4	76.3	76.8	74.6	75.8	77.7	73.8	74.9	76.2
Supply [b]															
OECD															
U.S. (50 States)	9.5	9.4	9.0	9.1	8.9	9.0	9.0	9.1	9.0	9.0	9.0	9.0	9.3	9.0	9.0
Canada	2.7	2.6	2.8	2.7	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.6	2.6
North Sea [c]	6.4	6.2	5.9	6.3	6.3	6.1	6.1	6.4	6.6	6.4	6.6	6.8	6.2	6.2	6.6
Other OECD	1.6	1.6	1.6	1.4	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.7	1.6	1.5	1.6
Total OECD	20.2	19.9	19.2	19.6	19.3	19.1	19.1	19.7	19.9	19.7	19.8	20.1	19.7	19.3	19.9
Non-OECD															
OPEC	30.9	30.8	30.1	30.0	30.3	28.9	29.0	29.1	29.4	30.7	31.1	31.2	30.4	29.3	30.6
Former Soviet Union	7.3	7.2	7.2	7.3	7.2	7.3	7.3	7.4	7.4	7.3	7.3	7.4	7.2	7.3	7.3
China	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.2	3.2	3.3
Mexico	3.6	3.6	3.5	3.5	3.6	3.4	3.4	3.5	3.6	3.6	3.6	3.6	3.5	3.5	3.6
Other Non-OECD	10.7	10.8	10.8	11.0	11.1	10.9	11.1	11.2	11.3	11.3	11.4	11.4	10.8	11.1	11.3
Total Non-OECD	55.7	55.5	54.7	54.9	55.4	53.7	53.9	54.5	54.8	56.1	56.6	56.9	55.2	54.4	56.1
Total World Supply	75.9	75.3	74.0	74.5	74.7	72.8	73.0	74.1	74.7	75.8	76.5	77.0	74.9	73.6	76.0
Stock Changes															
Net Stock Withdrawals or Additions (-)															
U.S. (50 States including SPR)	-0.3	-0.7	0.0	0.1	0.4	-0.2	0.2	0.4	0.2	-0.6	-0.3	0.5	-0.2	0.2	0.0
Other	-1.4	-2.1	-0.4	0.1	0.6	0.7	1.3	1.7	1.9	-0.6	-0.4	0.2	-0.9	1.1	0.3
Total Stock Withdrawals	-1.7	-2.8	-0.4	0.2	0.9	0.5	1.4	2.2	2.1	-1.2	-0.7	0.7	-1.2	1.3	0.2
OECD Comm. Stocks, End (bill. bbls.)	2.7	2.9	2.9	2.8	2.8	2.8	2.7	2.6	2.5	2.6	2.7	2.6	2.8	2.6	2.6
Non-OPEC Supply	45.0	44.6	43.9	44.5	44.4	43.9	44.0	45.0	45.3	45.1	45.4	45.8	44.5	44.3	45.4
Net Exports from Former Soviet Union	2.8	3.0	3.1	3.1	2.9	3.3	3.2	3.1	3.0	3.1	3.1	3.2	3.0	3.1	3.1

[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)

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Imported Crude Oil [a]															
(dollars per barrel)	**13.44**	**12.40**	**11.87**	**10.86**	**10.92**	**15.44**	*19.66*	*23.58*	*23.83*	*22.75*	*22.00*	*21.83*	**12.12**	*17.47*	*22.58*
Natural Gas Wellhead															
(dollars per thousand cubic feet)	**2.02**	**2.07**	**1.92**	**1.84**	**1.74**	**2.04**	*2.28*	*2.60*	*2.39*	*2.08*	*2.22*	*2.59*	**1.96**	*2.17*	*2.32*
Petroleum Products															
Gasoline Retail [b] (dollars per gallon)															
All Grades	**1.10**	**1.10**	**1.07**	**1.03**	**0.99**	**1.17**	*1.25*	*1.33*	*1.36*	*1.38*	*1.36*	*1.31*	**1.07**	*1.19*	*1.35*
Regular Unleaded	**1.05**	**1.05**	**1.03**	**0.99**	**0.95**	**1.13**	*1.21*	*1.30*	*1.32*	*1.34*	*1.32*	*1.28*	**1.03**	*1.15*	*1.31*
No. 2 Diesel Oil, Retail															
(dollars per gallon)	**1.08**	**1.05**	**1.02**	**1.00**	**0.97**	**1.08**	*1.19*	*1.31*	*1.29*	*1.27*	*1.25*	*1.27*	**1.04**	*1.14*	*1.27*
No. 2 Heating Oil, Wholesale															
(dollars per gallon)	**0.47**	**0.43**	**0.39**	**0.38**	**0.36**	**0.44**	*0.58*	*0.68*	*0.69*	*0.66*	*0.65*	*0.68*	**0.42**	*0.52*	*0.67*
No. 2 Heating Oil, Retail															
(dollars per gallon)	**0.91**	**0.85**	**0.77**	**0.79**	**0.80**	**0.82**	*0.89*	*1.06*	*1.11*	*1.07*	*1.01*	*1.07*	**0.85**	*0.89*	*1.09*
No. 6 Residual Fuel Oil, Retail [c]															
(dollars per barrel)	**13.58**	**13.27**	**12.32**	**11.77**	**11.28**	**14.05**	*18.59*	*23.08*	*23.15*	*20.78*	*19.89*	*21.25*	**12.73**	*16.55*	*21.34*
Electric Utility Fuels															
Coal															
(dollars per million Btu)	**1.26**	**1.26**	**1.25**	**1.23**	**1.24**	**1.23**	*1.23*	*1.24*	*1.25*	*1.26*	*1.24*	*1.23*	**1.25**	*1.23*	*1.24*
Heavy Fuel Oil [d]															
(dollars per million Btu)	**2.12**	**2.17**	**2.07**	**1.93**	**1.72**	**2.27**	*2.91*	*3.79*	*3.60*	*3.37*	*3.25*	*3.51*	**2.07**	*2.60*	*3.44*
Natural Gas															
(dollars per million Btu)	**2.61**	**2.46**	**2.26**	**2.31**	**2.19**	**2.42**	*2.71*	*3.15*	*3.07*	*2.65*	*2.75*	*3.18*	**2.38**	*2.64*	*2.85*
Other Residential															
Natural Gas															
(dollars per thousand cubic feet)	**6.38**	**7.33**	**8.90**	**6.64**	**6.09**	**6.83**	*8.85*	*7.23*	*6.75*	*7.10*	*8.82*	*7.26*	**6.82**	*6.77*	*7.10*
Electricity															
(cents per kilowatthour)	**7.96**	**8.43**	**8.55**	**8.09**	**7.79**	*8.28*	*8.38*	*8.04*	*7.67*	*8.09*	*8.36*	*7.91*	**8.28**	*8.13*	*8.02*

[a] Refiner acquisition cost (RAC) of imported crude oil.

[b] Average self-service cash prices.

[c] Average for all sulfur contents.

[d] Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Data are estimated for the third quarter of 1999. 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)

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Supply															
Crude Oil Supply															
Domestic Production [a]	6.47	6.37	6.07	6.11	6.00	5.95	5.92	6.09	6.05	5.97	5.94	5.94	6.25	5.99	5.97
Alaska	1.23	1.17	1.13	1.17	1.13	1.04	0.98	1.05	0.99	0.93	0.93	0.96	1.17	1.05	0.95
Lower 48	5.25	5.20	4.94	4.93	4.86	4.91	4.94	5.05	5.06	5.04	5.01	4.98	5.08	4.94	5.02
Net Imports (including SPR) [b]	8.00	8.80	9.00	8.57	8.40	8.65	8.77	8.66	8.41	9.10	9.38	8.83	8.60	8.62	8.93
Other SPR Supply	0.00	0.00	0.00	0.00	0.00	0.03	0.08	0.10	0.00	0.00	0.00	0.00	0.00	0.05	0.00
SPR Stock Withdrawn or Added (-)	0.00	0.00	0.00	-0.09	-0.01	-0.03	-0.01	0.02	0.00	0.00	0.00	0.00	-0.02	-0.01	0.00
Other Stock Withdrawn or Added (-)	-0.33	0.02	0.24	-0.15	-0.20	0.15	0.26	-0.06	-0.12	-0.05	0.05	0.05	-0.05	0.04	-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	0.20	0.11	0.07	0.09	0.23	0.28	0.38	0.21	0.20	0.21	0.22	0.21	0.11	0.27	0.21
Total Crude Oil Supply	14.34	15.30	15.38	14.53	14.42	14.99	15.31	14.92	14.54	15.24	15.58	15.04	14.89	14.91	15.10
Other Supply															
NGL Production	1.84	1.82	1.67	1.71	1.72	1.79	1.81	1.77	1.78	1.78	1.77	1.76	1.76	1.77	1.77
Other Hydrocarbon and Alcohol Inputs	0.39	0.37	0.37	0.39	0.36	0.37	0.33	0.38	0.37	0.35	0.36	0.38	0.38	0.36	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	0.84	0.88	0.89	0.93	0.86	0.87	0.91	0.88	0.85	0.90	0.92	0.88	0.89	0.88	0.89
Net Product Imports [c]	1.03	1.22	1.18	1.24	1.27	1.26	1.15	1.18	1.11	1.18	1.22	1.33	1.17	1.21	1.21
Product Stock Withdrawn or Added (-) [d]	0.03	-0.72	-0.26	0.30	0.56	-0.35	-0.06	0.47	0.34	-0.52	-0.36	0.44	-0.17	0.16	-0.02
Total Supply	18.46	18.86	19.24	19.10	19.20	18.93	19.46	19.60	19.00	18.93	19.49	19.84	18.92	19.30	19.32
Demand															
Motor Gasoline	7.78	8.37	8.52	8.33	7.94	8.46	8.70	8.61	8.00	8.58	8.84	8.73	8.25	8.43	8.54
Jet Fuel	1.58	1.61	1.61	1.68	1.71	1.62	1.62	1.71	1.71	1.65	1.71	1.74	1.62	1.67	1.70
Distillate Fuel Oil	3.59	3.43	3.37	3.45	3.70	3.33	3.39	3.63	3.76	3.43	3.39	3.64	3.46	3.52	3.56
Residual Fuel Oil	0.85	0.88	0.99	0.83	0.95	0.77	0.86	0.77	0.76	0.63	0.64	0.73	0.89	0.84	0.69
Other Oils [e]	4.65	4.57	4.75	4.80	4.90	4.74	4.85	4.88	4.77	4.64	4.91	5.00	4.69	4.84	4.83
Total Demand	18.46	18.86	19.24	19.10	19.20	18.93	19.43	19.60	19.00	18.93	19.49	19.84	18.92	19.29	19.32
Total Petroleum Net Imports	9.02	10.02	10.19	9.82	9.67	9.91	9.92	9.84	9.53	10.28	10.60	10.16	9.76	9.83	10.15
Closing Stocks (million barrels)															
Crude Oil (excluding SPR)	334	332	310	324	341	328	304	310	321	326	321	316	324	310	316
Total Motor Gasoline	216	222	207	216	216	216	200	201	212	211	207	208	216	201	208
Finished Motor Gasoline	167	177	164	172	168	172	156	159	166	169	165	167	172	159	167
Blending Components	49	45	43	44	48	44	44	43	47	42	42	41	44	43	41
Jet Fuel	43	44	46	45	41	44	48	47	43	44	47	46	45	47	46
Distillate Fuel Oil	125	136	153	156	125	133	146	143	110	117	136	141	156	143	141
Residual Fuel Oil	41	40	40	45	40	43	37	38	35	40	41	44	45	38	44
Other Oils [e]	265	313	334	291	279	297	308	266	264	299	314	265	291	266	265
Total Stocks (excluding SPR)	1024	1087	1089	1076	1043	1061	1043	1005	985	1037	1065	1020	1076	1005	1020
Crude Oil in SPR	563	563	563	571	572	575	575	574	574	574	574	574	571	574	574
Total Stocks (including SPR)	1587	1651	1653	1647	1614	1636	1619	1579	1559	1611	1639	1594	1647	1579	1594

[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*, 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 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 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	*6.25*	*5.61*	*0.64*	*0.09*	*0.56*
Lower 48 States	*5.29*	*4.67*	*0.62*	*0.07*	*0.54*
Alaska	*0.97*	*0.94*	*0.03*	*0.01*	*0.01*

Note: Components provided are for the fourth quarter 2000. 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)

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Supply															
Total Dry Gas Production	**4.72**	**4.71**	**4.72**	**4.71**	**4.61**	**4.65**	*4.71*	*4.71*	*4.77*	*4.72*	*4.74*	*4.74*	**18.86**	*18.69*	*18.97*
Net Imports	**0.75**	**0.71**	**0.77**	**0.76**	**0.83**	**0.79**	*0.85*	*0.86*	*0.89*	*0.86*	*0.92*	*0.92*	**2.99**	*3.33*	*3.60*
Supplemental Gaseous Fuels	**0.03**	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	*0.03*	*0.03*	*0.04*	*0.03*	*0.03*	*0.03*	**0.12**	*0.12*	*0.13*
Total New Supply	**5.50**	**5.45**	**5.52**	**5.50**	**5.48**	**5.47**	*5.59*	*5.60*	*5.70*	*5.61*	*5.69*	*5.70*	**21.97**	*22.15*	*22.70*
Underground Working Gas Storage															
Opening	**6.52**	**5.53**	**6.45**	**7.29**	**7.04**	**5.79**	*6.50*	*7.31*	*6.81*	*5.35*	*6.18*	*7.10*	**6.52**	*7.04*	*6.81*
Closing	**5.53**	**6.45**	**7.29**	**7.04**	**5.79**	**6.50**	*7.31*	*6.81*	*5.35*	*6.18*	*7.10*	*6.68*	**7.04**	*6.81*	*6.68*
Net Withdrawals	**0.99**	**-0.92**	**-0.84**	**0.25**	**1.25**	**-0.71**	*-0.80*	*0.49*	*1.46*	*-0.83*	*-0.92*	*0.42*	**-0.52**	*0.23*	*0.13*
Total Supply	**6.50**	**4.53**	**4.68**	**5.75**	**6.73**	**4.76**	*4.79*	*6.09*	*7.16*	*4.78*	*4.77*	*6.12*	**21.45**	*22.38*	*22.83*
Balancing Item [a]	**0.16**	**0.19**	**-0.05**	**-0.41**	**0.04**	**0.00**	*-0.13*	*-0.42*	*0.05*	*0.15*	*-0.17*	*-0.50*	**-0.11**	*-0.52*	*-0.46*
Total Primary Supply	**6.66**	**4.72**	**4.63**	**5.34**	**6.77**	**4.76**	*4.66*	*5.67*	*7.21*	*4.93*	*4.61*	*5.62*	**21.34**	*21.86*	*22.37*
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*	**1.24**	*1.23*	*1.24*
Pipeline Use	**0.23**	**0.16**	**0.16**	**0.18**	**0.23**	**0.16**	*0.16*	*0.19*	*0.23*	*0.17*	*0.16*	*0.19*	**0.73**	*0.75*	*0.75*
Residential	**2.13**	**0.78**	**0.36**	**1.20**	**2.24**	**0.81**	*0.40*	*1.35*	*2.39*	*0.82*	*0.35*	*1.37*	**4.48**	*4.80*	*4.93*
Commercial	**1.21**	**0.57**	**0.44**	**0.81**	**1.25**	**0.59**	*0.46*	*0.90*	*1.37*	*0.62*	*0.43*	*0.89*	**3.03**	*3.21*	*3.30*
Industrial (Incl. Cogenerators)	**2.23**	**1.99**	**2.02**	**2.17**	**2.16**	**2.00**	*2.00*	*2.19*	*2.26*	*1.99*	*1.94*	*2.12*	**8.41**	*8.35*	*8.31*
Cogenerators	**0.51**	**0.49**	**0.54**	**0.60**	**0.53**	**0.50**	*0.55*	*0.61*	*0.54*	*0.51*	*0.56*	*0.63*	**2.14**	*2.19*	*2.23*
Electricity Production															
Electric Utilities	**0.50**	**0.86**	**1.29**	**0.61**	**0.54**	**0.85**	*1.28*	*0.67*	*0.60*	*0.99*	*1.38*	*0.68*	**3.26**	*3.34*	*3.66*
Nonutilities (Excl. Cogen.) [b]	**0.04**	**0.04**	**0.05**	**0.05**	**0.04**	**0.04**	*0.05*	*0.05*	*0.05*	*0.04*	*0.05*	*0.05*	**0.18**	*0.18*	*0.19*
Total Demand	**6.66**	**4.72**	**4.63**	**5.34**	**6.77**	**4.76**	*4.66*	*5.67*	*7.21*	*4.93*	*4.61*	*5.62*	**21.34**	*21.86*	*22.37*

[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.

[b] Quarterly estimates and projections for gas consumption by nonutility generators are based on estimates for quarterly gas-fired generation at nonutilities, supplied by the Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF), Energy Information Administration (EIA), based on annual data reported to EIA on Form EIA-867 (Annual Nonutility Power Producer Report). Annual projections for nonutility gas consumption, as well as the detail on independent power producers' share of gas consumption, are provided by CNEAF.

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)

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Supply															
Production	**281.6**	**275.4**	**278.6**	**282.6**	**282.3**	**268.1**	*269.6*	*289.6*	*287.9*	*278.3*	*273.4*	*289.5*	**1118.1**	*1109.6*	*1129.1*
Appalachia	**119.5**	**114.0**	**113.2**	**113.6**	**118.2**	**113.9**	*107.4*	*119.3*	*118.7*	*116.2*	*106.7*	*117.4*	**460.4**	*458.8*	*459.0*
Interior	**43.1**	**42.4**	**41.5**	**41.4**	**41.5**	**37.4**	*38.4*	*41.9*	*40.6*	*37.1*	*37.1*	*40.0*	**168.4**	*159.2*	*154.8*
Western	**119.0**	**119.0**	**123.8**	**127.6**	**122.5**	**116.8**	*123.8*	*128.4*	*128.6*	*124.9*	*129.6*	*132.1*	**489.4**	*491.6*	*515.3*
Primary Stock Levels [a]															
Opening	**34.0**	**41.0**	**38.3**	**37.2**	**36.1**	**42.4**	*41.5*	*35.1*	*34.4*	*41.3*	*41.9*	*35.5*	**34.0**	*36.1*	*34.4*
Closing	**41.0**	**38.3**	**37.1**	**36.1**	**42.4**	**41.5**	*35.1*	*34.4*	*41.3*	*41.9*	*35.5*	*34.6*	**36.1**	*34.4*	*34.6*
Net Withdrawals	**-7.0**	**2.7**	**1.2**	**1.0**	**-6.2**	**0.8**	*6.5*	*0.7*	*-6.9*	*-0.6*	*6.4*	*0.9*	**-2.2**	*1.8*	*-0.3*
Imports	**1.8**	**2.2**	**2.1**	**2.5**	**2.2**	**2.1**	*2.2*	*2.3*	*2.5*	*2.5*	*2.5*	*2.6*	**8.7**	*8.9*	*10.2*
Exports	**18.6**	**20.7**	**19.9**	**18.8**	**13.0**	**14.4**	*17.0*	*17.8*	*15.4*	*15.6*	*15.9*	*15.8*	**78.0**	*62.1*	*62.7*
Total Net Domestic Supply	**257.8**	**259.5**	**262.0**	**267.4**	**265.3**	**256.6**	*261.3*	*274.9*	*268.1*	*264.6*	*266.5*	*277.2*	**1046.6**	*1058.2*	*1076.4*
Secondary Stock Levels [b]															
Opening	**106.4**	**115.0**	**125.0**	**113.4**	**129.5**	**144.2**	*152.7*	*130.6*	*143.7*	*144.5*	*157.1*	*140.3*	**106.4**	*129.5*	*143.7*
Closing	**115.0**	**125.0**	**113.4**	**129.5**	**144.2**	**152.7**	*130.6*	*143.7*	*144.5*	*157.1*	*140.3*	*150.0*	**129.5**	*143.7*	*150.0*
Net Withdrawals	**-8.6**	**-10.0**	**11.6**	**-15.9**	**-14.7**	**-8.6**	*22.2*	*-13.1*	*-0.8*	*-12.6*	*16.8*	*-9.7*	**-23.1**	*-14.2*	*-6.3*
Waste Coal Supplied to IPPs [c]	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**2.4**	*2.7*	*2.9*	*3.2*	*3.2*	*3.2*	*3.2*	**9.2**	*10.3*	*12.7*
Total Supply	**251.5**	**251.7**	**275.8**	**253.6**	**252.9**	**250.5**	*286.2*	*264.7*	*270.5*	*255.2*	*286.4*	*270.7*	**1032.7**	*1054.3*	*1082.8*
Demand															
Coke Plants	**6.7**	**7.2**	**7.2**	**7.0**	**6.8**	**7.1**	*6.8*	*7.1*	*7.1*	*6.9*	*6.8*	*7.0*	**28.2**	*27.8*	*27.9*
Electricity Production															
Electric Utilities	**220.4**	**218.4**	**252.3**	**219.7**	**217.3**	**214.7**	*248.6*	*224.3*	*230.1*	*217.9*	*248.4*	*229.8*	**910.9**	*904.9*	*926.1*
Nonutilities (Excl. Cogen.) [d]	**6.0**	**6.2**	**7.4**	**8.4**	**8.8**	**10.7**	*12.7*	*12.7*	*12.8*	*12.5*	*13.3*	*13.3*	**28.1**	*44.9*	*51.9*
Retail and General Industry [e]	**20.1**	**18.2**	**17.8**	**19.5**	**19.4**	**18.0**	*18.0*	*20.6*	*20.5*	*17.9*	*17.9*	*20.6*	**75.6**	*76.1*	*76.8*
Total Demand [f]	**253.3**	**250.0**	**284.7**	**254.7**	**252.2**	**250.5**	*286.2*	*264.7*	*270.5*	*255.2*	*286.4*	*270.7*	**1042.7**	*1053.6*	*1082.8*
Discrepancy [g]	**-1.9**	**1.7**	**-8.9**	**-1.0**	**0.7**	**0.0**	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	***-10.1***	*0.6*	*0.0*

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

[b] Secondary stocks are held by users.

[c] Estimated independent power producers (IPPs) consumption of waste coal. This item includes waste coal and coal slurry reprocessed into briquettes, 1.2 million tons in 1999 and 3.1 million tons in 2000.

[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 1998 and projections for 1999 and 2000 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] Synfuels plant demand in 1993 was 1.7 million tons per quarter and is assumed to remain at that level.

[f] Total Demand includes estimated IPP consumption.

[g] 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)

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Supply															
Net Utility Generation															
Coal	437.6	435.0	500.3	434.5	431.7	426.5	480.6	438.7	457.1	433.2	491.0	454.3	1807.5	1777.4	1835.6
Petroleum	20.8	28.5	37.2	23.7	26.9	23.0	31.6	18.5	22.1	16.5	20.2	18.8	110.2	100.0	77.7
Natural Gas	48.0	80.8	121.1	59.3	52.0	81.3	122.7	63.6	57.5	94.6	131.8	65.4	309.2	319.5	349.3
Nuclear	162.6	154.7	179.1	177.3	181.2	166.1	193.5	172.9	177.1	160.8	188.8	170.1	673.7	713.8	696.8
Hydroelectric	86.5	88.1	69.6	60.2	83.4	79.8	69.2	63.8	79.4	79.9	66.0	64.1	304.4	296.3	289.5
Geothermal and Other [a]	1.9	1.4	1.9	2.0	1.6	1.0	0.6	0.7	0.5	0.5	0.6	0.8	7.2	3.9	2.4
Subtotal	757.3	788.6	909.3	757.0	776.8	777.7	898.1	758.3	793.8	785.5	898.4	773.5	3212.2	3210.9	3251.3
Nonutility Generation [b]															
Coal	16.2	16.2	19.4	22.1	21.3	24.8	29.6	30.6	29.2	28.3	30.6	31.6	73.9	106.3	119.7
Petroleum	3.9	3.8	4.1	4.6	4.0	3.9	4.2	4.7	4.1	4.0	4.3	4.8	16.4	16.8	17.2
Natural Gas	49.8	47.7	51.9	58.1	50.9	48.7	53.0	59.4	51.9	49.8	54.1	60.6	207.6	212.0	216.5
Other Gaseous Fuels [c]	3.0	2.9	3.1	3.5	2.9	2.8	3.1	3.4	2.9	2.7	3.0	3.3	12.5	12.2	11.9
Hydroelectric	4.2	4.0	4.3	4.9	4.3	4.1	4.5	5.0	4.5	4.3	4.7	5.2	17.4	18.0	18.7
Geothermal and Other [d]	15.1	19.4	12.9	3.3	17.8	17.0	19.6	22.1	18.9	17.9	19.8	22.0	50.7	76.5	78.5
Subtotal	92.3	94.0	95.8	96.5	101.3	101.4	114.0	125.2	111.5	107.0	116.5	127.7	378.6	441.8	462.6
Total Generation	849.6	882.6	1005.0	853.5	878.0	879.1	1012.1	883.5	905.3	892.5	1014.9	901.2	3590.7	3652.7	3713.8
Net Imports [e]	5.8	6.9	10.9	5.2	2.0	7.6	9.8	7.6	6.0	6.1	8.9	6.4	28.8	27.0	27.4
Total Supply	855.4	889.5	1015.9	858.6	880.0	886.7	1021.9	891.1	911.3	898.6	1023.8	907.6	3619.5	3679.7	3741.2
Losses and Unaccounted for [f]	52.8	85.0	57.9	40.1	55.7	73.9	64.2	61.1	48.6	76.0	65.9	64.2	235.8	254.9	254.7
Demand															
Electric Utility Sales															
Residential	273.5	248.9	346.6	255.0	286.0	249.2	339.5	261.4	304.1	258.4	338.1	267.8	1124.0	1136.0	1168.4
Commercial	216.5	230.2	271.9	230.2	226.0	236.5	276.1	234.5	236.8	236.9	275.2	237.6	948.9	973.1	986.4
Industrial	249.7	263.6	271.6	262.4	248.5	264.6	273.4	262.2	255.4	263.4	274.5	264.6	1047.3	1048.7	1057.8
Other	23.6	24.1	27.0	25.1	23.9	24.4	27.2	25.5	25.9	25.2	28.0	26.2	99.9	101.0	105.4
Subtotal	763.4	766.9	917.1	772.7	784.4	774.6	916.2	783.5	822.2	783.9	915.8	796.2	3220.1	3258.8	3318.0
Nonutility Gener. for Own Use [b]	39.2	37.6	40.9	45.8	39.8	38.1	41.5	46.5	40.4	38.7	42.1	47.2	163.6	166.0	168.5
Total Demand	802.7	804.5	958.0	818.6	824.3	812.7	957.7	830.0	862.6	822.6	957.9	843.4	3383.7	3424.7	3486.5
Memo:															
Nonutility Sales to Electric Utilities [b]	53.0	56.4	54.8	50.7	61.4	63.2	72.5	78.7	71.0	68.2	74.4	80.5	215.0	275.9	294.1

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

[b] Electricity from nonutility sources, including cogenerators and small power producers. Quarterly estimates and projections for nonutility net sales, own use, and generation by fuel source supplied by the Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration (EIA), based on annual data reported to EIA on Form EIA-867, "Annual Nonutility Power Producer Report."

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

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

[e] Data for 1998 are estimates.

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

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		
	1997	1998	1999	2000	1997-1998	1998-1999	1999-2000
Electric Utilities							
Hydroelectric Power [a]	**3.521**	**3.178**	*3.162*	*3.022*	**-9.7**	*-0.5*	*-4.4*
Geothermal, Solar and Wind Energy [b]	**0.115**	**0.109**	*0.039*	*0.008*	**-5.2**	*-64.2*	*-79.5*
Biofuels [c]	**0.020**	**0.021**	*0.021*	*0.021*	**5.0**	*0.0*	*0.0*
Total	**3.656**	**3.307**	*3.221*	*3.052*	**-9.5**	*-2.6*	*-5.2*
Nonutility Power Generators							
Hydroelectric Power [a]	**0.185**	**0.179**	*0.186*	*0.192*	**-3.2**	*3.9*	*3.2*
Geothermal, Solar and Wind Energy [b]	**0.235**	**0.253**	*0.303*	*0.351*	**7.7**	*19.8*	*15.8*
Biofuels [c]	**0.576**	**0.584**	*0.580*	*0.578*	**1.4**	*-0.7*	*-0.3*
Total	**0.996**	**1.016**	*1.069*	*1.121*	**2.0**	*5.2*	*4.9*
Total Power Generation	**4.652**	**4.323**	*4.291*	*4.173*	**-7.1**	*-0.7*	*-2.7*
Other Sectors [d]							
Residential and Commercial [e]	**0.553**	**0.568**	*0.574*	*0.583*	**2.7**	*1.1*	*1.6*
Industrial [f]	**1.498**	**1.515**	*1.542*	*1.569*	**1.1**	*1.8*	*1.8*
Transportation [g]	**0.087**	**0.095**	*0.095*	*0.095*	**9.2**	*0.0*	*0.0*
Total	**2.138**	**2.178**	*2.211*	*2.247*	**1.9**	*1.5*	*1.6*
Net Imported Electricity [h]	**0.259**	**0.233**	*0.219*	*0.222*	**-10.0**	*-6.0*	*1.4*
Total Renewable Energy Demand	**7.048**	**6.734**	*6.720*	*6.642*	**-4.5**	*-0.2*	*-1.2*

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

[b]Also includes photovoltaic and solar thermal energy.

[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														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Real Gross Domestic Product (GDP) (billion chained 1992 dollars).....................	5488	5649	5865	6062	6136	6079	6244	6390	6611	6762	6995	7270	7552	*7837*	*8012*
Imported Crude Oil Price [a] (nominal dollars per barrel)	14.00	18.13	14.57	18.08	21.75	18.70	18.20	16.14	15.52	17.14	20.61	18.50	12.12	*17.47*	*22.58*
Petroleum Supply															
Crude Oil Production [b] (million barrels per day)	8.68	8.35	8.14	7.61	7.36	7.42	7.17	6.85	6.66	6.56	6.46	6.45	6.25	*5.99*	*5.97*
Total Petroleum Net Imports (including SPR) (million barrels per day)	5.44	5.91	6.59	7.20	7.16	6.63	6.94	7.62	8.05	7.89	8.50	9.16	9.76	*9.83*	*10.15*
Energy Demand															
World Petroleum (million barrels per day)	61.8	63.1	64.9	65.9	66.0	66.6	66.8	67.0	68.3	69.9	71.3	73.0	73.8	*74.9*	*76.2*
U.S. Petroleum (million barrels per day)	16.33	16.72	17.34	17.37	17.04	16.77	17.10	17.24	17.72	17.72	18.31	18.62	18.92	*19.29*	*19.32*
Natural Gas (trillion cubic feet)	16.22	17.21	18.03	18.80	18.72	19.03	19.54	20.28	20.71	21.58	21.96	21.97	21.34	*21.86*	*22.37*
Coal (million short tons)......................................	797	830	877	891	897	898	907	943	950	962	1006	1029	1044	*1054*	*1083*
Electricity (billion kilowatthours)															
Utility Sales [c]	2369	2457	2578	2647	2713	2762	2763	2861	2935	3013	3098	3140	3220	*3259*	*3318*
Nonutility Own Use [d]	NA	NA	NA	97	113	122	137	138	150	158	158	161	164	*166*	*168*
Total	2369	2457	2578	2744	2826	2884	2901	2999	3085	3171	3256	3301	3384	*3425*	*3487*
Total Energy Demand [e] (quadrillion Btu)	NA	NA	NA	NA	84.2	84.3	85.6	87.4	89.3	91.0	94.0	94.2	94.7	*96.5*	*97.5*
Total Energy Demand per Dollar of GDP (thousand Btu per 1992 Dollar)..................	NA	NA	NA	NA	13.72	13.86	13.71	13.68	13.50	13.45	13.43	12.96	12.54	*12.31*	*12.16*

[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 1998 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 CONTROL0999.

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

	Year														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Macroeconomic															
Real Gross Domestic Product															
(billion chained 1992 dollars)	5488	5649	5865	6062	6136	6079	6244	6390	6611	6762	6995	7270	7552	*7837*	*8012*
GDP Implicit Price Deflator															
(Index, 1992=1.000)	0.806	0.831	0.861	0.897	0.936	0.973	1.000	1.026	1.051	1.075	1.096	1.116	1.127	*1.141*	*1.158*
Real Disposable Personal Income															
(billion chained 1992 Dollars)	4077	4155	4325	4412	4490	4484	4605	4667	4773	4906	5043	5183	5348	*5509*	*5676*
Manufacturing Production															
(Index, 1992=1.000)	0.881	0.928	0.971	0.990	0.985	0.962	1.000	1.037	1.099	1.159	1.214	1.296	1.349	*1.389*	*1.406*
Real Fixed Investment															
(billion chained 1992 dollars)	805	799	818	832	806	741	783	843	916	966	1051	1138	1268	*1377*	*1414*
Real Exchange Rate															
(Index, 1990=1.000)	NA	NA	NA	NA	0.999	1.007	1.013	1.057	1.034	0.961	1.017	1.105	1.152	*1.164*	*1.152*
Business Inventory Change															
(billion chained 1992 dollars)	-4.2	5.1	9.5	19.2	6.6	-6.1	-9.2	6.1	11.1	11.2	12.0	20.1	19.9	*-0.5*	*1.0*
Producer Price Index															
(index, 1982=1.000)	1.002	1.028	1.069	1.122	1.163	1.165	1.172	1.189	1.205	1.248	1.277	1.276	1.244	*1.254*	*1.285*
Consumer Price Index															
(index, 1982-1984=1.000)	1.097	1.137	1.184	1.240	1.308	1.363	1.404	1.446	1.483	1.525	1.570	1.606	1.631	*1.668*	*1.715*
Petroleum Product Price Index															
(index, 1982=1.000)	0.532	0.568	0.539	0.612	0.748	0.671	0.647	0.620	0.591	0.608	0.701	0.680	0.513	*0.610*	*0.755*
Non-Farm Employment															
(millions)	99.3	102.0	105.2	107.9	109.4	108.3	108.6	110.7	114.1	117.2	119.6	122.7	125.8	*128.5*	*130.3*
Commercial Employment															
(millions)	62.9	65.2	67.8	70.0	71.3	70.8	71.2	73.2	76.1	78.8	81.1	83.9	86.6	*89.4*	*91.1*
Total Industrial Production															
(index, 1992=1.000)	0.890	0.932	0.974	0.991	0.989	0.970	1.000	1.035	1.091	1.144	1.196	1.267	1.314	*1.345*	*1.367*
Housing Stock															
(millions)	98.0	99.8	101.6	102.9	103.5	104.5	105.5	106.8	108.2	109.6	111.0	112.5	114.3	*115.9*	*117.2*
Weather [a]															
Heating Degree-Days															
U.S.	4295	4334	4653	4726	4016	4200	4441	4700	4483	4531	4713	4542	3951	*4360*	*4494*
New England	6517	6546	6715	6887	5848	5960	6844	6728	6672	6559	6679	6662	5680	*6216*	*6520*
Middle Atlantic	5665	5699	6088	6134	4998	5177	5964	5948	5934	5831	5986	5809	4812	*5537*	*5751*
U.S. Gas-Weighted	4442	4391	4804	4856	4139	4337	4458	4754	4659	4707	4980	4802	4185	*4604*	*4734*
Cooling Degree-Days (U.S.)	1249	1269	1283	1156	1260	1331	1040	1218	1220	1293	1180	1156	1411	*1295*	*1233*

[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 CONTROL0999.

Table A3. Annual International Petroleum Supply and Demand Balance

(Millions Barrels per Day, Except OECD Commercial Stocks)

	Year														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Demand [a]															
OECD															
U.S. (50 States)	**16.3**	**16.7**	**17.3**	**17.4**	**17.0**	**16.8**	**17.1**	**17.2**	**17.7**	**17.7**	**18.3**	**18.6**	**18.9**	*19.3*	*19.3*
Europe [b]	**12.1**	**12.3**	**12.4**	**12.5**	**12.6**	**13.4**	**13.6**	**13.5**	**13.6**	**14.1**	**14.3**	**14.4**	**14.7**	*14.9*	*15.1*
Japan	**4.4**	**4.5**	**4.8**	**5.0**	**5.1**	**5.3**	**5.4**	**5.4**	**5.7**	**5.7**	**5.9**	**5.7**	**5.5**	*5.5*	*5.6*
Other OECD	**2.5**	**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*
Total OECD	**35.3**	**36.0**	**37.1**	**37.6**	**37.5**	**38.1**	**38.8**	**39.0**	**39.9**	**40.6**	**41.4**	**41.8**	**42.2**	*42.9*	*43.3*
Non-OECD															
Former Soviet Union	**9.0**	**9.0**	**8.9**	**8.7**	**8.4**	**8.3**	**6.8**	**5.6**	**4.8**	**4.6**	**4.0**	**4.3**	**4.2**	*4.2*	*4.2*
Europe	**2.2**	**2.2**	**2.2**	**2.1**	**1.9**	**1.4**	**1.3**	**1.3**	**1.3**	**1.3**	**1.4**	**1.4**	**1.5**	*1.5*	*1.6*
China	**2.0**	**2.1**	**2.3**	**2.4**	**2.3**	**2.5**	**2.7**	**3.0**	**3.1**	**3.3**	**3.5**	**3.8**	**3.9**	*4.1*	*4.3*
Other Asia	**3.8**	**4.1**	**4.4**	**4.9**	**5.3**	**5.7**	**6.2**	**6.8**	**7.9**	**7.9**	**8.5**	**8.8**	**8.7**	*8.8*	*9.1*
Other Non-OECD	**9.5**	**9.7**	**10.0**	**10.3**	**10.5**	**10.6**	**11.0**	**11.4**	**11.8**	**12.1**	**12.4**	**12.8**	**13.2**	*13.4*	*13.7*
Total Non-OECD	**26.5**	**27.1**	**27.7**	**28.3**	**28.5**	**28.5**	**28.0**	**28.1**	**29.0**	**29.3**	**29.9**	**31.2**	**31.5**	*32.0*	*32.9*
Total World Demand	**61.8**	**63.1**	**64.9**	**66.0**	**66.0**	**66.6**	**66.8**	**67.0**	**68.9**	**69.9**	**71.3**	**73.0**	**73.8**	*74.9*	*76.2*
Supply [c]															
OECD															
U.S. (50 States)	**11.0**	**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*	*9.0*
Canada	**1.8**	**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*	*2.6*
North Sea [d]	**3.8**	**3.8**	**3.8**	**3.7**	**3.9**	**4.1**	**4.5**	**4.8**	**5.5**	**5.9**	**6.3**	**6.2**	**6.2**	*6.2*	*6.6*
Other OECD	**1.4**	**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*	*1.6*
Total OECD	**17.9**	**17.9**	**17.8**	**17.1**	**17.1**	**17.5**	**17.9**	**18.0**	**18.7**	**19.2**	**19.7**	**19.9**	**19.7**	*19.3*	*19.9*
Non-OECD															
OPEC	**19.3**	**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*	*30.6*
Former Soviet Union	**12.3**	**12.5**	**12.5**	**12.1**	**11.4**	**10.4**	**8.9**	**8.0**	**7.3**	**7.1**	**7.1**	**7.1**	**7.2**	*7.3*	*7.3*
China	**2.6**	**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*
Mexico	**2.8**	**2.9**	**2.9**	**2.9**	**3.0**	**3.2**	**3.2**	**3.2**	**3.2**	**3.1**	**3.3**	**3.4**	**3.5**	*3.5*	*3.6*
Other Non-OECD	**6.8**	**11.3**	**7.3**	**7.7**	**8.0**	**8.1**	**8.4**	**8.7**	**9.2**	**9.9**	**10.2**	**10.5**	**10.8**	*11.1*	*11.3*
Total Non-OECD	**43.9**	**44.6**	**47.0**	**48.9**	**49.7**	**49.1**	**49.1**	**49.4**	**49.6**	**50.7**	**52.0**	**54.2**	**55.2**	*54.4*	*56.1*
Total World Supply	**61.8**	**62.5**	**64.8**	**65.9**	**66.8**	**66.7**	**67.0**	**67.4**	**68.3**	**69.9**	**71.8**	**74.1**	**74.9**	*73.6*	*76.0*
Total Stock Withdrawals	**0.0**	**0.6**	**0.1**	**0.0**	**-0.8**	**-0.1**	**-0.2**	**-0.3**	**0.1**	**0.0**	**-0.4**	**-1.1**	**-1.2**	*1.3*	*0.2*
OECD Comm. Stocks, End (bill. bbls.)	**2.7**	**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*	*2.6*
Net Exports from Former Soviet Union	**3.4**	**3.5**	**3.6**	**3.4**	**3.0**	**2.1**	**2.1**	**2.3**	**2.4**	**2.5**	**3.0**	**2.9**	**3.0**	*3.1*	*3.1*

[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)

	Year														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Imported Crude Oil [a]															
(dollars per barrel)	**14.00**	**18.13**	**14.57**	**18.08**	**21.75**	**18.70**	**18.20**	**16.14**	**15.52**	**17.14**	**20.61**	**18.50**	**12.12**	*17.47*	*22.58*
Natural Gas Wellhead															
(dollars per thousand cubic feet)	**1.94**	**1.66**	**1.69**	**1.69**	**1.71**	**1.64**	**1.74**	**2.04**	**1.85**	**1.55**	**2.16**	**2.32**	**1.96**	*2.17*	*2.32*
Petroleum Products															
Gasoline Retail [b] (dollars per gallon)															
All Grades	**0.88**	**0.91**	**0.92**	**1.02**	**1.17**	**1.15**	**1.14**	**1.13**	**1.13**	**1.16**	**1.25**	**1.24**	**1.07**	*1.19*	*1.35*
Regular Unleaded	**0.88**	**0.91**	**0.91**	**0.99**	**1.13**	**1.10**	**1.09**	**1.07**	**1.08**	**1.11**	**1.20**	**1.20**	**1.03**	*1.15*	*1.31*
No. 2 Diesel Oil, Retail															
(dollars per gallon)	**0.88**	**0.93**	**0.91**	**0.99**	**1.16**	**1.12**	**1.10**	**1.11**	**1.11**	**1.10**	**1.22**	**1.19**	**1.04**	*1.14*	*1.27*
No. 2 Heating Oil, Wholesale															
(dollars per gallon)	**0.49**	**0.53**	**0.47**	**0.56**	**0.70**	**0.62**	**0.58**	**0.54**	**0.51**	**0.51**	**0.64**	**0.59**	**0.42**	*0.52*	*0.67*
No. 2 Heating Oil, Retail															
(dollars per gallon)	**0.84**	**0.80**	**0.81**	**0.90**	**1.06**	**1.02**	**0.93**	**0.91**	**0.89**	**0.87**	**0.99**	**0.99**	**0.85**	*0.89*	*1.09*
No. 6 Residual Fuel Oil, Retail [c]															
(dollars per barrel)	**14.46**	**17.76**	**14.04**	**16.20**	**18.66**	**14.32**	**14.21**	**14.00**	**14.79**	**16.49**	**19.01**	**17.82**	**12.73**	*16.55*	*21.34*
Electric Utility Fuels															
Coal															
(dollars per million Btu)	**1.58**	**1.51**	**1.47**	**1.44**	**1.45**	**1.45**	**1.41**	**1.38**	**1.36**	**1.32**	**1.29**	**1.27**	**1.25**	*1.23*	*1.24*
Heavy Fuel Oil [d]															
(dollars per million Btu)	**2.40**	**2.98**	**2.41**	**2.85**	**3.22**	**2.49**	**2.46**	**2.36**	**2.40**	**2.60**	**3.01**	**2.79**	**2.07**	*2.60*	*3.44*
Natural Gas															
(dollars per million Btu)	**2.35**	**2.24**	**2.26**	**2.36**	**2.32**	**2.15**	**2.33**	**2.56**	**2.23**	**1.98**	**2.64**	**2.76**	**2.38**	*2.64*	*2.85*
Other Residential															
Natural Gas															
(dollars per thousand cubic feet)	**5.83**	**5.55**	**5.47**	**5.64**	**5.80**	**5.82**	**5.89**	**6.17**	**6.41**	**6.06**	**6.35**	**6.95**	**6.82**	*6.77*	*7.10*
Electricity															
(cents per kilowatthour)	**7.4**	**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*	*8.0*

[a] Refiner acquisition cost (RAC) of imported crude oil.

[b] Average self-service cash prices.

[c] Average for all sulfur contents.

[d] 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														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Supply															
Crude Oil Supply															
Domestic Production [a]	**8.68**	**8.35**	**8.14**	**7.61**	**7.36**	**7.42**	**7.17**	**6.85**	**6.66**	**6.56**	**6.46**	**6.45**	**6.25**	*5.99*	*5.97*
Alaska	**1.87**	**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*	*0.95*
Lower 48	**6.81**	**6.39**	**6.12**	**5.74**	**5.58**	**5.62**	**5.46**	**5.26**	**5.10**	**5.08**	**5.07**	**5.16**	**5.08**	*4.94*	*5.02*
Net Imports (including SPR) [b]	**4.02**	**4.52**	**4.95**	**5.70**	**5.79**	**5.67**	**5.99**	**6.69**	**6.96**	**7.14**	**7.40**	**8.12**	**8.60**	*8.62*	*8.93*
Other SPR Supply	**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**	*0.05*	*0.00*
Stock Draw (Including SPR)	**-0.08**	**-0.12**	**0.00**	**-0.09**	**0.02**	**-0.01**	**0.01**	**-0.06**	**-0.02**	**0.09**	**0.05**	**-0.06**	**-0.05**	*0.04*	*-0.02*
Product Supplied and Losses	**-0.05**	**-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*
Unaccounted-for Crude Oil	**0.14**	**0.14**	**0.20**	**0.20**	**0.26**	**0.20**	**0.26**	**0.17**	**0.27**	**0.19**	**0.22**	**0.14**	**0.11**	*0.27*	*0.21*
Total Crude Oil Supply	**12.72**	**12.85**	**13.25**	**13.40**	**13.41**	**13.30**	**13.41**	**13.61**	**13.87**	**13.97**	**14.19**	**14.66**	**14.89**	*14.91*	*15.10*
Other Supply															
NGL Production	**1.55**	**1.59**	**1.62**	**1.55**	**1.56**	**1.66**	**1.70**	**1.74**	**1.73**	**1.76**	**1.83**	**1.82**	**1.76**	*1.77*	*1.77*
Other Hydrocarbon and Alcohol Inputs	**0.11**	**0.12**	**0.11**	**0.11**	**0.13**	**0.15**	**0.20**	**0.25**	**0.26**	**0.30**	**0.31**	**0.34**	**0.38**	*0.36*	*0.37*
Crude Oil Product Supplied	**0.05**	**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*
Processing Gain	**0.62**	**0.64**	**0.66**	**0.66**	**0.68**	**0.71**	**0.77**	**0.77**	**0.77**	**0.77**	**0.84**	**0.85**	**0.89**	*0.88*	*0.89*
Net Product Imports [c]	**1.41**	**1.39**	**1.63**	**1.50**	**1.38**	**0.96**	**0.94**	**0.93**	**1.09**	**0.75**	**1.10**	**1.04**	**1.17**	*1.21*	*1.21*
Product Stock Withdrawn	**-0.12**	**0.09**	**0.03**	**0.13**	**-0.14**	**-0.04**	**0.06**	**-0.05**	**0.00**	**0.15**	**0.03**	**-0.09**	**-0.17**	*0.16*	*-0.02*
Total Supply	**16.33**	**16.72**	**17.33**	**17.37**	**17.04**	**16.76**	**17.10**	**17.26**	**17.72**	**17.72**	**18.31**	**18.62**	**18.92**	*19.30*	*19.32*
Demand															
Motor Gasoline [d]	**6.94**	**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*	*8.54*
Jet Fuel	**1.31**	**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*	*1.70*
Distillate Fuel Oil	**2.91**	**2.98**	**3.12**	**3.16**	**3.02**	**2.92**	**2.98**	**3.04**	**3.16**	**3.21**	**3.37**	**3.44**	**3.46**	*3.52*	*3.56*
Residual Fuel Oil	**1.42**	**1.26**	**1.38**	**1.37**	**1.23**	**1.16**	**1.09**	**1.08**	**1.02**	**0.85**	**0.85**	**0.80**	**0.89**	*0.84*	*0.69*
Other Oils [e]	**3.75**	**3.90**	**4.03**	**3.95**	**3.95**	**3.99**	**4.20**	**4.17**	**4.41**	**4.36**	**4.63**	**4.77**	**4.69**	*4.84*	*4.83*
Total Demand	**16.33**	**16.72**	**17.34**	**17.37**	**17.04**	**16.77**	**17.10**	**17.24**	**17.72**	**17.72**	**18.31**	**18.62**	**18.92**	*19.29*	*19.32*
Total Petroleum Net Imports	**5.44**	**5.91**	**6.59**	**7.20**	**7.16**	**6.63**	**6.94**	**7.62**	**8.05**	**7.89**	**8.50**	**9.16**	**9.76**	*9.83*	*10.15*
Closing Stocks (million barrels)															
Crude Oil (excluding SPR)	**331**	**349**	**330**	**341**	**323**	**325**	**318**	**335**	**337**	**303**	**284**	**305**	**324**	*310*	*316*
Total Motor Gasoline	**233**	**226**	**228**	**213**	**220**	**219**	**216**	**226**	**215**	**202**	**195**	**210**	**216**	*201*	*208*
Jet Fuel	**50**	**50**	**44**	**41**	**52**	**49**	**43**	**40**	**47**	**40**	**40**	**44**	**45**	*47*	*46*
Distillate Fuel Oil	**155**	**134**	**124**	**106**	**132**	**144**	**141**	**141**	**145**	**130**	**127**	**138**	**156**	*143*	*141*
Residual Fuel Oil	**47**	**47**	**45**	**44**	**49**	**50**	**43**	**44**	**42**	**37**	**46**	**40**	**45**	*38*	*44*
Other Oils [f]	**265**	**260**	**267**	**257**	**261**	**267**	**263**	**273**	**275**	**258**	**250**	**259**	**291**	*266*	*265*

[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)

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Supply															
Total Dry Gas Production	**16.06**	**16.62**	**17.10**	**17.31**	**17.81**	**17.70**	**17.84**	**18.10**	**18.82**	**18.60**	**18.79**	**18.90**	**18.86**	*18.69*	*18.97*
Net Imports	**0.69**	**0.94**	**1.22**	**1.27**	**1.45**	**1.64**	**1.92**	**2.21**	**2.46**	**2.69**	**2.78**	**2.84**	**2.99**	*3.33*	*3.60*
Supplemental Gaseous Fuels	**0.11**	**0.10**	**0.10**	**0.11**	**0.12**	**0.11**	**0.12**	**0.12**	**0.11**	**0.11**	**0.11**	**0.10**	**0.12**	*0.12*	*0.13*
Total New Supply	**16.86**	**17.66**	**18.42**	**18.69**	**19.38**	**19.45**	**19.88**	**20.42**	**21.39**	**21.40**	**21.69**	**21.84**	**21.97**	*22.15*	*22.70*
Total Underground Storage															
Opening	**6.45**	**6.57**	**6.55**	**6.65**	**6.33**	**6.94**	**6.78**	**6.64**	**6.65**	**6.97**	**6.50**	**6.51**	**6.52**	*7.04*	*6.81*
Closing	**6.57**	**6.55**	**6.65**	**6.33**	**6.94**	**6.78**	**6.64**	**6.65**	**6.97**	**6.50**	**6.51**	**6.52**	**7.04**	*6.81*	*6.68*
Net Withdrawals	**-0.12**	**0.02**	**-0.10**	**0.33**	**-0.61**	**0.16**	**0.14**	**-0.01**	**-0.32**	**0.46**	**-0.01**	**-0.01**	**-0.52**	*0.23*	*0.13*
Total Supply	**16.74**	**17.68**	**18.32**	**19.02**	**18.77**	**19.61**	**20.02**	**20.42**	**21.08**	**21.86**	**21.68**	**21.84**	**21.45**	*22.38*	*22.83*
Balancing Item [a]	**-0.52**	**-0.47**	**-0.29**	**-0.22**	**-0.05**	**-0.58**	**-0.47**	**-0.14**	**-0.37**	**-0.28**	**0.29**	**0.13**	**-0.11**	*-0.52*	*-0.46*
Total Primary Supply	**16.22**	**17.21**	**18.03**	**18.80**	**18.72**	**19.03**	**19.54**	**20.28**	**20.71**	**21.58**	**21.96**	**21.97**	**21.34**	*21.86*	*22.37*
Demand															
Lease and Plant Fuel	**0.92**	**1.15**	**1.10**	**1.07**	**1.24**	**1.13**	**1.17**	**1.17**	**1.12**	**1.22**	**1.25**	**1.20**	**1.24**	*1.23*	*1.24*
Pipeline Use	**0.49**	**0.52**	**0.61**	**0.63**	**0.66**	**0.60**	**0.59**	**0.62**	**0.69**	**0.70**	**0.71**	**0.75**	**0.73**	*0.75*	*0.75*
Residential	**4.31**	**4.31**	**4.63**	**4.78**	**4.39**	**4.56**	**4.69**	**4.96**	**4.85**	**4.85**	**5.24**	**4.98**	**4.48**	*4.80*	*4.93*
Commercial	**2.32**	**2.43**	**2.67**	**2.72**	**2.62**	**2.73**	**2.80**	**2.86**	**2.90**	**3.03**	**3.16**	**3.22**	**3.03**	*3.21*	*3.30*
Industrial (Incl. Nonutilities)	**5.58**	**5.95**	**6.38**	**6.82**	**7.02**	**7.23**	**7.53**	**7.98**	**8.17**	**8.58**	**8.87**	**8.84**	**8.59**	*8.53*	*8.50*
Cogenerators [b]	**NA**	**NA**	**NA**	**NA**	**1.30**	**1.41**	**1.70**	**1.80**	**1.98**	**2.18**	**2.30**	**2.16**	**2.14**	*2.19*	*2.23*
Other Nonutil. Gen. [b]	**NA**	**NA**	**NA**	**NA**	**0.09**	**0.16**	**0.18**	**0.22**	**0.16**	**0.17**	**0.16**	**0.18**	**0.18**	*0.18*	*0.19*
Electric Utilities	**2.60**	**2.84**	**2.64**	**2.79**	**2.79**	**2.79**	**2.77**	**2.68**	**2.99**	**3.20**	**2.73**	**2.97**	**3.26**	*3.34*	*3.66*
Total Demand	**16.22**	**17.21**	**18.03**	**18.80**	**18.72**	**19.03**	**19.54**	**20.28**	**20.71**	**21.58**	**21.96**	**21.97**	**21.34**	*21.86*	*22.37*

[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.

[b]Annual projections for nonutility gas consumption, as well as the detail on independent power producers' share of gas consumption, are provided by the office of Coal, Nuclear, Electric and Alternative Fuels, Energy Information Administration.

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)

	Year														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Supply															
Production	890.3	918.8	950.3	980.7	1029.1	996.0	997.5	945.4	1033.5	1033.0	1063.9	1089.9	1118.1	1109.6	1129.1
Appalachia	NA	NA	NA	464.8	489.0	457.8	456.6	409.7	445.4	434.9	451.9	467.8	460.4	458.8	459.0
Interior	NA	NA	NA	198.1	205.8	195.4	195.7	167.2	179.9	168.5	172.8	170.9	168.4	159.2	154.8
Western	NA	NA	NA	317.9	334.3	342.8	345.3	368.5	408.3	429.6	439.1	451.3	489.4	491.6	515.3
Primary Stock Levels [a]															
Opening	33.1	32.1	28.3	30.4	29.0	33.4	33.0	34.0	25.3	33.2	34.4	28.6	34.0	36.1	34.4
Closing	32.1	28.3	30.4	29.0	33.4	33.0	34.0	25.3	33.2	34.4	28.6	34.0	36.1	34.4	34.6
Net Withdrawals	1.0	3.8	-2.1	1.4	-4.4	0.4	-1.0	8.7	-7.9	-1.2	5.8	-5.3	-2.2	1.8	-0.3
Imports	2.2	1.7	2.1	2.9	2.7	3.4	3.8	7.3	7.6	7.2	7.1	7.5	8.7	8.9	10.2
Exports	85.5	79.6	95.0	100.8	105.8	109.0	102.5	74.5	71.4	88.5	90.5	83.5	78.0	62.1	62.7
Total Net Domestic Supply	808.0	844.7	855.3	884.2	921.6	890.9	897.8	886.9	961.8	950.4	986.3	1008.5	1046.6	1058.2	1076.4
Secondary Stock Levels [b]															
Opening	170.2	175.2	185.5	158.4	146.1	168.2	167.7	163.7	120.5	136.1	134.6	123.0	106.4	129.5	143.7
Closing	175.2	185.5	158.4	146.1	168.2	167.7	163.7	120.5	136.1	134.6	123.0	106.4	129.5	143.7	150.0
Net Withdrawals	-5.0	-10.2	27.0	12.3	-22.1	0.5	4.0	43.2	-15.7	1.5	11.7	16.6	-23.1	-14.2	-6.3
Waste Coal Supplied to IPPs [c]	0.0	0.0	0.0	0.0	0.0	0.0	6.0	6.4	7.9	8.5	8.8	8.1	9.2	10.3	12.7
Total Supply	803.1	834.4	882.3	896.5	899.4	891.4	907.8	936.5	954.0	960.4	1006.7	1033.2	1032.7	1054.3	1082.8
Demand															
Coke Plants	35.9	37.0	41.9	40.5	38.9	33.9	32.4	31.3	31.7	33.0	31.7	30.2	28.2	27.8	27.9
Electricity Production															
Electric Utilities	685.1	717.9	758.4	766.9	773.5	772.3	779.9	813.5	817.3	829.0	874.7	900.4	910.9	904.9	926.1
Nonutilities (Excl. Cogen.) [d]	NA	NA	NA	0.9	1.6	10.2	14.6	17.1	19.5	20.8	22.2	21.6	28.1	44.9	51.9
Retail and General Industry [e]	75.6	75.2	76.3	82.3	83.1	81.5	80.2	81.1	81.2	78.9	76.9	77.1	75.6	76.1	76.8
Total Demand [f]	796.6	830.0	876.5	890.6	897.1	897.8	907.0	943.1	949.7	961.7	1005.6	1029.2	1042.7	1053.6	1082.8
Discrepancy [g]	6.5	4.4	5.8	5.9	2.4	-6.4	0.8	-6.6	4.3	-1.3	1.2	4.0	-10.1	0.6	0.0

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

[b] Secondary stocks are held by users.

[c] Estimated independent power producers (IPPs) consumption of waste coal. This item includes waste coal and coal slurry reprocessed into briquettes, 1.2 million tons in 1999 and 3.1 million tons in 2000.

[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 1998 and projections for 1999 and 2000 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] Synfuels plant demand in 1993 was 1.7 million tons per quarter and is assumed to remain at that level.

[f] Total Demand includes estimated IPP consumption.

[g] 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)

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Supply															
Net Utility Generation															
Coal	**1385.8**	**1463.8**	**1540.7**	**1553.7**	**1559.6**	**1551.2**	**1575.9**	**1639.2**	**1635.5**	**1652.9**	**1737.5**	**1787.8**	**1807.5**	*1777.4*	*1835.6*
Petroleum	**136.6**	**118.5**	**148.9**	**158.3**	**117.0**	**111.5**	**88.9**	**99.5**	**91.0**	**60.8**	**67.3**	**77.8**	**110.2**	*100.0*	*77.7*
Natural Gas	**248.5**	**272.6**	**252.8**	**266.6**	**264.1**	**264.2**	**263.9**	**258.9**	**291.1**	**307.3**	**262.7**	**283.6**	**309.2**	*319.5*	*349.3*
Nuclear	**414.0**	**455.3**	**527.0**	**529.4**	**576.9**	**612.6**	**618.8**	**610.3**	**640.4**	**673.4**	**674.7**	**628.6**	**673.7**	*713.8*	*696.8*
Hydroelectric	**290.8**	**249.7**	**222.9**	**265.1**	**279.9**	**275.5**	**239.6**	**265.1**	**243.7**	**293.7**	**328.0**	**337.2**	**304.4**	*296.3*	*289.5*
Geothermal and Other [a]	**11.5**	**12.3**	**12.0**	**11.3**	**10.7**	**10.1**	**10.2**	**9.6**	**8.9**	**6.4**	**7.2**	**7.5**	**7.2**	*3.9*	*2.4*
Subtotal	**2487.3**	**2572.1**	**2704.3**	**2784.3**	**2808.2**	**2825.0**	**2797.2**	**2882.5**	**2910.7**	**2994.5**	**3077.4**	**3122.5**	**3212.2**	*3210.9*	*3251.3*
Nonutility Generation [b]	**NA**	**NA**	**NA**	**NA**	**221.5**	**253.3**	**301.8**	**325.2**	**354.9**	**375.9**	**382.4**	**384.7**	**378.6**	*441.8*	*462.6*
Total Generation	**NA**	**NA**	**NA**	**NA**	**3029.6**	**3078.3**	**3099.0**	**3207.8**	**3265.6**	**3370.4**	**3459.9**	**3507.2**	**3590.7**	*3652.7*	*3713.8*
Net Imports	**35.9**	**46.3**	**31.8**	**11.0**	**2.3**	**19.6**	**25.4**	**27.8**	**44.8**	**39.2**	**38.0**	**36.6**	**28.8**	*27.0*	*27.4*
Total Supply	**NA**	**NA**	**NA**	**NA**	**3032.0**	**3098.0**	**3124.4**	**3235.6**	**3310.5**	**3409.6**	**3497.9**	**3543.8**	**3619.5**	*3679.7*	*3741.2*
Losses and Unaccounted for [c]	**NA**	**NA**	**NA**	**NA**	**206.2**	**214.2**	**223.7**	**236.3**	**225.7**	**238.4**	**242.3**	**242.8**	**235.8**	*254.9*	*254.7*
Demand															
Electric Utility Sales															
Residential	**819.1**	**850.4**	**892.9**	**905.5**	**924.0**	**955.4**	**935.9**	**994.8**	**1008.5**	**1042.5**	**1082.5**	**1075.8**	**1124.0**	*1136.0*	*1168.4*
Commercial	**630.5**	**660.4**	**699.1**	**725.9**	**751.0**	**765.7**	**761.3**	**794.6**	**820.3**	**862.7**	**887.4**	**928.4**	**948.9**	*973.1*	*986.4*
Industrial	**830.5**	**858.2**	**896.5**	**925.7**	**945.5**	**946.6**	**972.7**	**977.2**	**1008.0**	**1012.7**	**1030.4**	**1032.7**	**1047.3**	*1048.7*	*1057.8*
Other	**88.6**	**88.2**	**89.6**	**89.8**	**92.0**	**94.3**	**93.4**	**94.9**	**97.8**	**95.4**	**97.5**	**102.9**	**99.9**	*101.0*	*105.4*
Subtotal	**2368.8**	**2457.3**	**2578.1**	**2646.8**	**2712.6**	**2762.0**	**2763.4**	**2861.5**	**2934.6**	**3013.3**	**3097.8**	**3139.8**	**3220.1**	*3258.8*	*3318.0*
Nonutility Own Use [b]	**NA**	**NA**	**NA**	**97.2**	**113.2**	**121.7**	**137.3**	**137.8**	**150.2**	**158.0**	**157.8**	**161.2**	**163.6**	*166.0*	*168.5*
Total Demand	**NA**	**NA**	**NA**	**2744.0**	**2825.8**	**2883.7**	**2900.7**	**2999.2**	**3084.8**	**3171.3**	**3255.6**	**3301.0**	**3383.7**	*3424.7*	*3486.5*
Memo:															
Nonutility Sales to Electric Utilities [d]	**NA**	**NA**	**NA**	**NA**	**108.2**	**131.6**	**164.4**	**187.5**	**204.7**	**217.9**	**224.7**	**223.5**	**215.0**	*275.9*	*294.1*

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

[b] For 1989 to 1991, estimates for nonutility generation are estimates made by the Energy Markets and Contingency Information Division, based on Form EIA-867 (Annual Nonutility Power Producer Report) data. Historical data and Projections for the same items are from the Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration, based on Form EIA-867.

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

[d] Historical data for nonutility sales to electric utilities are from the Energy Information Administration, *Annual Energy Review*, DOE/EIA-0389, Table 8.1, for 1982 to 1988; from Form EIA-867 (Annual Nonutility Power Producer Report) for 1989 to 1996.

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.