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COUNTRY ANALYSIS BRIEFS

United States

Last Updated: November 2005

Background

The United States of America is the world's largest energy producer, consumer, and net importer. It also ranks eleventh worldwide in reserves of oil, sixth in natural gas, and first in coal.

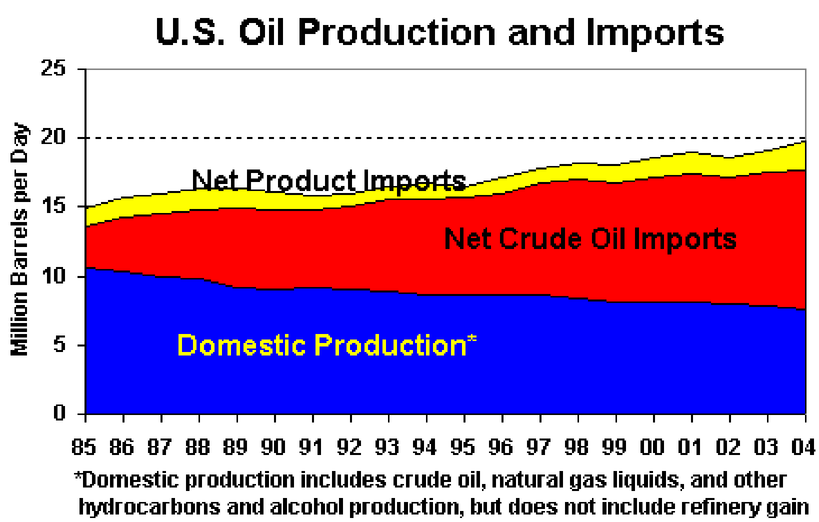
As of October 2005, the US economy continued to expand, with 2005 real growth in gross domestic product (GDP) running at about 3.5 percent. This follows real GDP growth of 4.2 percent in 2004. The U.S. unemployment rate was estimated at 5.0 percent in October, down slightly from 5.1 percent in September, with the economy creating 56,000 net jobs during the month.

For 2005, the U.S. merchandise trade deficit is expected to total $782 billion, up from $665 billion in 2004. The current account deficit now is running at about 6.6 percent of GDP, compared to 1.5 percent in 1995. The U.S. budget deficit was $319 billion in fiscal year (FY) 2005, down from $412 billion in FY 2004. Despite the deficits, the dollar has generally appreciated against several major currencies, including the Euro and the Japanese Yen, during 2005.

Oil

U.S. oil production has been declining for years. In 2005, Hurricanes Katrina and Rita slashed oil output from the Gulf of Mexico.

According to EIA's 2004 Annual Report on U.S. oil and natural gas reserves, the United States had 21.4 billion barrels of proved oil reserves as of December 31, 2004, the eleventh highest in the world. These reserves were concentrated overwhelmingly (over 80 percent) in four states. Texas had 22 percent of total US oil reserves, Louisiana had 20 percent, Alaska 20 percent, and California 18 percent (note: all of these figures include onshore plus Federal and state offshore reserves). U.S. proven oil reserves have declined more than 17 percent since 1990, with the largest single-year decline (1.6 billion barrels) occurring in 1991.



U.S. crude oil production, which declined following the oil price collapse of late 1985/early 1986, leveled off in the mid-1990s, and began falling again following the sharp decline in oil prices of late 1997/early 1998. During 2004, the United States produced around 7.6 million barrels per day (bbl/d) of oil, of which 5.4 million bbl/d was crude oil, 1.8 million bbl/d was natural gas liquids and 0.4 million bbl/d was other liquids. This compares to the 10.6 million bbl/d averaged during 1985. U.S. crude oil production, which averaged 5.4 million bbl/d during the first eight months of 2005, is now at 50-year lows.

The United States contains over 500,000 producing oil wells, the vast majority of which are considered "marginal" or "stripper" wells, generally producing only a few barrels per day of oil. During 2004, top oil producing areas included the Gulf of Mexico (1.5 million bbl/d), Texas onshore (1.1 million bbl/d), Alaska's North Slope (886,000 bbl/d), California (656,000 bbl/d), Louisiana onshore (228,000 bbl/d), New Mexico (176,000 bbl/d), Oklahoma (171,000 bbl/d), and Wyoming (141,000 bbl/d).

EIA expects that lower-48 States oil production in 2005 will decline by 340,000 bbl/d from 2004 levels, to 4.17 million bbl/d. For 2006, an increase of 400,000 bbl/d is expected. Much of the 2005 reduction and 2006 rebound is due to the disruption and subsequent recovery of production in the Gulf of Mexico.

Generally speaking, Lower-48 onshore production, particularly in Texas, has been falling in recent years, while offshore (mainly Gulf of Mexico) production has been rising. For 2005, prior to Hurricanes Katrina and Rita in August and September, Gulf of Mexico oil production had been expected to increase as new fields came online in late 2003 and 2004 (e.g., the southern Green Canyon deepwater area). By late 2005, the Mars, Mad Dog, Ursa, Thunder Horse and Nakika Federal Offshore fields had been expected to account for about 12 percent of Lower-48 oil production. Now, with the impacts of Hurricanes Katrina and Rita, this outlook has been thrown into question.

As of November 10, 2005, 46.7 percent of the Gulf of Mexico's 1.5 million bbl/d crude oil production capacity remained offline, with 39.8 percent of the area's 10 billion cubic feet per day (Bcf/d) of natural gas production capacity also down. EIA currently expects about 23 percent of the Gulf's crude oil production and 21 percent of its natural gas output to remain shut down through March 2006. Overall, through November 14, Hurricanes Katrina and Rita had caused a loss of nearly 86 million barrels of U.S. crude oil output, and over 440 Bcf of natural gas output. In addition, around 804,000 on bbl/d of crude refining capacity remained offline as of November 9.

The destructive 2005 hurricane season came as the Gulf of Mexico had just about fully recovered from Hurricane Ivan in late September 2004. That storm had also caused significant disruptions to Gulf of Mexico operations, with 102 pipelines affected and 27 platforms either destroyed or badly damaged. According to an assessment by the U.S Department of Interior's Minerals Management Service (MMS), "Of the 4,000 structures and 33,000 miles of pipelines in the gulf....150 platforms and 10,000 miles of pipelines were in the direct path of Hurricane Ivan"

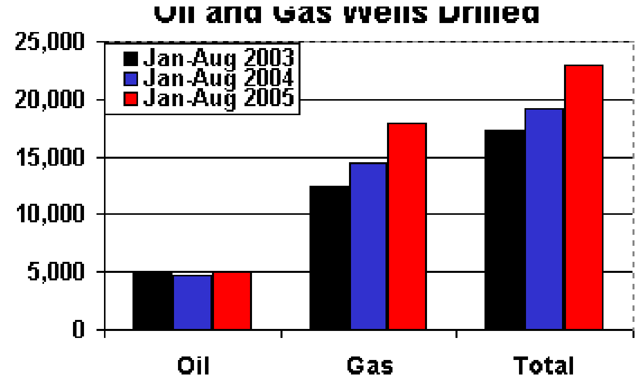
Meanwhile, Alaskan oil production is expected to decrease by 30,000 bbl/d in 2005 and by 20,000 bbl/d in 2006, to 860,000 bbl/d. This continues a steady decline since the state's peak output of 2.02 million bbl/d in 1988. For the period January-August 2005, Alaska averaged production of about 872,000 bbl/d of oil, or about 16 percent of total U.S. crude oil production. Over 400,000 bbl/d of Alaska's oil output comes from the giant Prudhoe Bay Field (major producers include BP, ExxonMobil, and ConocoPhillips), and is transported via the 800-mile Alyeska (Trans-Alaska) pipeline. An oilfield known as Alpine, owned 78 percent by ConocoPhillips and 22 percent by Anadarko, began production in November 2000. Alpine represents one of the largest North American onshore oil discoveries in years, producing around 63,000 bbl/d of high quality, light crude oil in 2004. Production at Alpine is to be maintained using tie-ins to the Nanuq and Fiord satellite fields beginning in late 2006. ConocoPhillips has been the largest oil producer in Alaska since acquiring Arco's Alaska fields in early 2000. The combined crude oil production rate from ConocoPhillips' Greater Kuparak and Western North Slope areas averaged about 156,000 bbl/d in 2004. ConocoPhillips also produced about 142,000 bbl/d at Prudhoe Bay.

In March 2004, the Energy Information Administration (EIA), in response to a Congressional request, issued an analysis of potential oil reserves and production from the Arctic National Wildlife Refuge (ANWR). The report projected that for the mean resource case (10.4 billion barrels technically recoverable, according to the U.S Geological Survey), ANWR peak production rates could range from 0.6 to 1.6 million bbl/d, with initial ANWR production possibly beginning around 2013, and peak production possible around 2024.

In recent years, production from deepwater areas of the Gulf of Mexico has been increasing rapidly, with deepwater wells now accounting for about two-thirds of total U.S. Gulf output. Large fields include ExxonMobil's $1.1 billion Hoover-Diana development (which started up in May 2000 and was producing 80,000 bbl/d by 2002), plus: 1) BP's $2.5 billion Atlantis project, scheduled to come online in the third quarter of 2006, with 150,000 bbl/d of peak oil production capacity; 2) BP's 1-billion-barrel Thunder Horse (previously "Crazy Horse") field, the largest single field ever discovered in the Gulf of Mexico, which came online in January 2005, with peak oil output of 250,000 bbl/d expected; 3) Crosby (developed by Shell, came online in late 2001, peak output of 60,000 bbl/d); 4) Holstein (BP; online in 2004); 5) King (BP); 6) King's Peak (BP); 7) Mad Dog (BHP Billiton; online in early 2005); 8) Marlin (BP); and 9) Nakika (Shell and BP; first production in December 2003; ramping up to 110,000 bbl/d) fields. For its part, BP has stated that it plans to accelerate its deepwater Gulf of Mexico production plans, including the planned $1 billion "Mardi Gras" deep-sea pipeline system, designed to transport more than 1 million bbl/d of oil.

In June 2003, Unocal announced its intentions to build a $500 million deepwater crude oil port, the Bulk Oil Offshore Transfer System (BOOTS) in the Gulf of Mexico 100 miles south of Beaumont, TX. The BOOTS system would have a capacity of 1.2 million bbl/d, and would be linked to refineries in Houston/Texas City, Beaumont/Port Arthur, and Lake Charles. As of October 2004, however, Unocal had placed BOOTS development on hold "pending receipt of sufficient volume commitments from crude oil import shippers."

Oil and Gas Wells Drilled



According to Baker Hughes Inc., which has tallied weekly U.S. drilling activity since 1940, domestic oil and natural gas drilling rebounded sharply from the low point of 488 reached in late April 1999, following the oil price collapse of late 1997. In mid-2001, for instance, the U.S. weekly "rig count" approached the 1,300 mark. After that, the U.S. "rig count" fell, reaching 843 as of mid-October 2002, before rising once again, reaching 1,479 during the week ending November 11, 2005. As of November 11, natural gas rigs outnumbered oil rigs in the United States more than five-fold (1,232 to 241).

Historically, U.S. drilling activity peaked in 1981, with a total of 91,553 wells (43,598 oil, 20,166 natural gas, 27,789 dry wells) drilled in that year. For 2004, a total of 33,813 wells (22,673 natural gas wells, 7,167 oil wells, and 3,973 dry wells) were drilled in the United States, up from the low point of 18,465 total wells drilled in 1999, and also up sharply from the 25,744 wells drilled in 2002. During January-September 2005, total U.S. oil and natural gas wells drilled were up 21 percent from the same period in 2004.

Petroleum Imports/Exports

With U.S. oil production declining and demand increasing, U.S. net oil imports are climbing steadily.

EIA forecasts that the United States will have total net oil imports (crude and products) of 12.2 million bbl/d during 2005, representing around 58 percent of total U.S. oil demand. Overall, the top suppliers of crude oil to the United States during January-August 2005 were Canada (1.6 million bbl/d), Mexico (1.6 million bbl/d), Saudi Arabia (1.5 million bbl/d), Venezuela (1.3 million bbl/d), and Nigeria (1.0 million bbl/d).

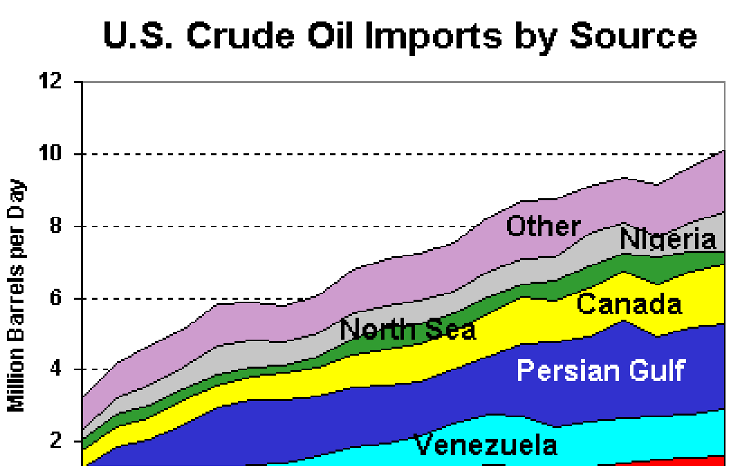
Refining/Downstream

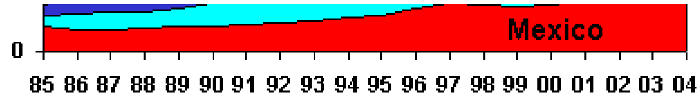
No new oil refineries have been built in the United States in 30 years, although existing refineries have increased capacity. In September and October 2005, Hurricanes Katrina and Rita knocked out refining capacity throughout the Gulf Coast region.

The United States experienced a steep decline in refining capacity between 1981 and the mid-1990s. Between 1981 and 1989, the number of U.S. refineries fell from 324 to 204, representing a loss of 3 million bbl/d in operable capacity (from 18.6 million bbl/d to 15.7 million bbl/d), while refining capacity utilization increased from 69 percent to 87 percent. Much of the decline in U.S. refining capacity resulted from the 1981 deregulation (elimination of price controls and allocations), which effectively removed the major prop from underneath many marginally profitable, often smaller, refineries.

Refinery closures have continued since 1989, bringing the total number of operable U.S. refineries to 148 as of January 1, 2005. In general, refineries that have closed were relatively small and had less favorable economics than other refineries in their market area. Also, in recent years, some smaller, less-economic refineries that needed additional investments for environmental reasons in order to stay in business found closing preferable because they predicted that they could not stay competitive in the long term.

While some refineries have closed, and no new refineries have been built in nearly 30 years, many existing refineries have expanded their capacities. As a result of “capacity creep," whereby existing refineries create additional refining capacity from the same physical structure, capacity per operating refinery increased by 28 percent over the 1990 to 1998 period. Overall, since the mid-1990s, U.S. refinery capacity has increased from 15.0 million bbl/d in 1994 to 17.1 million bbl/d in September 2004. As of November 4, 2005, utilization of operating capacity at U.S. refineries was averaging around 84 percent, down from 91 percent on September 16, 2005 following Hurricanes Katrina and Rita.





Financial Performance, Mergers and Acquisitions

With oil prices in the $60 per barrel range, U.S. oil companies are experiencing strong revenues and profits.

Twenty-five major U.S. energy companies reported overall net income (excluding unusual items) of $26.0 billion on revenues of $295.1 billion during the third quarter of 2005. This level of net income represented a 69 percent increase relative to the third quarter of 2004 (see EIA's "Financial News for Major Energy Companies "). Domestic upstream oil and natural gas production operations accounted for $8.5 billion of net income, with domestic refining and marketing operations earning an additional $7.0 billion. Foreign upstream oil and natural gas production operations accounted for $7.6 billion of net income, while foreign refining and marketing operations accounted for $2.0 billion.

Independent oil and natural gas producers, oil field companies and refiner/marketers reported a sharp increase in net income (up 139 percent) during the second quarter of 2005 compared to the second quarter of 2005 (see EIA's "Financial News for Independent Energy Companies"). This increase in net income was due primarily to large increases in the prices of natural gas and crude oil, and a rise in gross refining margins of 17 percent year-over-year.

On October 13, 2005, the Wall Street Journal (WSJ) reported that Occidental Petroleum Corporation had agreed to acquire Vintage Petroleum Inc. for about $3.5 billion of cash and stock. Other recent acquisitions reported by the Wall Street Journal include: 1) Valero Energy Corp. agreed to acquire Premcor Inc. for $6.9 billion in cash and stock (reported April 25, 2005); 2) ChevronTexaco Corporation agreed to buy Unocal Corporation for about $16.8 billion of cash and stock (April 5, 2005); and 3) Marathon Oil agreed to acquire from Ashland Corporation the 38 percent of the Marathon Ashland Petroleum refining/marketing joint venture that it did not already own (March 19, 2004). Marathon reportedly paid about $3 billion (about $1.1 billion of cash and stock and the assumption of about $1.9 billion in debt) for Ashland's share in the refining/marketing joint venture. In addition to acquiring full ownership of the Marathon Ashland Petroleum assets, Marathon also acquired 61 Valvoline Instant Oil Change outlets and other related assets currently owned by Ashland.

Consumption

The United Statesconsumed an average of about 20.6 million bbl/d of oil during the first nine months of 2005, the same amount year-over-year as in 2004. Of this, motor gasoline consumption was 9.1 million bbl/d (or 44 percent of the total), distillate fuel oil consumption was 4.1 million bbl/d (20 percent), jet fuel consumption was 1.6 million bbl/d (8 percent), and residual fuel oil consumption was 0.9 million bbl/d (4 percent). For 2005 as a whole, EIA's Short-Term Energy Outlook projects that U.S. petroleum demand will decline by 16,000 bbl/d, to an average 20.6 million bbl/d, in response to the combined effects of the hurricanes and high crude oil and product prices. EIA expects motor gasoline, jet fuel, and residual demand all to remain about flat -- at 9.1 million bbl/d, 1.6 million bbl/d, and 0.9 million bbl/d, respectively. EIA expects distillate demand in 2005 to grow by about 1%, to 4.1 million bbl/d. Finally, EIA forecasts demand for "other oils" (natural gas liquids, liquefied refinery gas, other liquids, etc.) to decline by over 4%, to 4.9 million bbl/d, in 2005.

Petroleum Prices

Average retail regular gasoline prices increased sharply after Hurricanes Katrina and Rita. EIA's latest Short-Term Energy Outlook forecasts gasoline prices (self-serve, regular) to average close to $2.38 per gallon for November 2005, down from $2.72 per gallon in October. The average pump price for the third quarter of 2005 is now expected to be about $2.56 per gallon, up $0.67 per gallon from the third quarter of last year. Hurricane recovery should result in further price decreases by the first quarter of 2006. Annual gasoline prices are projected to average $2.29 per gallon in 2005 and $2.43 per gallon in 2006. Should colder weather prevail, retail gasoline prices are projected to be 10-14 cents per gallon higher, on average, during the winter months. The real price of gasoline (in inflation adjusted 2005 dollars) remains below the 1981 peak.

Strategic Petroleum Reserve (SPR)

The U.S. Strategic Petroleum Reserve reached 700 million barrels on August 17, 2005. The Reserve was then used in the aftermath of Hurricane Katrina, with an announced sale of 30 million barrels.

In December 1975, the Energy Policy and Conservation Act (EPCA) was passed, officially establishing the Strategic Petroleum Reserve (SPR) as a reserve of up to 1 billion barrels. To store the reserve oil, the U.S. government acquired several salt caverns along the Gulf of Mexico coastline. The first crude oil was delivered to the SPR in 1977 and stored at the West Hackberry storage site near Lake Charles, LA. Other major storage sites include: Bryan Mound and Big Hill in Texas and Bayou Choctaw in Louisiana. Total storage capacity at the SPR is currently 700 million barrels.

In mid-November 2001, President Bush directed the Department of Energy (DOE) to fill the SPR to its capacity of 700 million barrels to "maximize long-term protection against oil supply disruptions." On August 17, 2005, the SPR reached its goal of 700 million barrels, just two weeks before Hurricane Katrina hit. On August 31, 2005, President George W. Bush authorized the SPR to loan oil to help refineries whose operations had been affected by Hurricane Katrina. In addition, the President announced the sale of 30 million barrels to maintain supplies and calm markets. As of November 14, 2005, the SPR contained around 684 million barrels of oil -- the largest emergency oil stockpile in the world. The SPR has a maximum drawdown capability of 4.3 million bbl/d for 90 days, with oil beginning to arrive in the marketplace 15 days after a presidential decision to initiate a drawdown. The SPR drawdown rate declines to 3.2 million bbl/d from days 91-120, to 2.2 million bbl/d for days 121-150, and to 1.3 million bbl/d for days 151-180. Prior to Hurricane Katrina, other withdrawals from the SPR occurred in 1985, 1990, 1991, 1996-97, and 2004.

Under EPCA, there is no preset "trigger" for withdrawing oil from the SPR. Instead, the President determines that drawdown is required by "a severe energy supply interruption or by obligations of the United States" under the International Energy Agency. EPCA defines a "severe energy supply interruption" as one which: 1) "is, or is likely to be, of significant scope and duration, and of an emergency nature;" 2) "may cause major adverse impact on national safety or the national economy" (including an oil price spike); and 3) "results, or is likely to result, from an interruption in the supply of imported petroleum products, or from sabotage or an act of God." Should the President decide to order an emergency drawdown of the SPR, oil would be distributed mainly by competitive sale to the highest bidder(s). This would be accomplished in a 4-step process, including a "Notice of Sale," receipt of bids, selection of bidders, and finally delivery of oil.

U.S. Energy Sanctions

The U.S. maintains sanctions on Iran, but has lifted nearly all of its sanctions on Libya , opening the door to oil investment there.

Since August 1996, the Iran-Libya Sanctions Act (ILSA) has imposed mandatory and discretionary sanctions on non-U.S. companies that invest more than $20 million annually (lowered in August 1997 from $40 million) in the Iranian oil and natural gas sectors. On August 3, 2001, President Bush signed into law the ILSA Extension Act of 2001. This provided for a 5-year extension of ILSA with amendments that affect certain of the investment provisions. In addition, the United States has maintained various sanctions against Iran since 1979, following the seizure of the U.S. embassy in Tehran on November 4 of that year. In 1995, President Clinton signed two Executive Orders prohibiting U.S. companies and their foreign subsidiaries from conducting business with Iran. Executive Order 12957 specifically banned any "contract for the financing of the development of petroleum resources located in Iran." On March 10, 2005, President Bush extended sanctions for another year, citing Iran's "continued support for terrorism, its efforts to undermine the Middle East peace process and its efforts to acquire weapons of mass destruction."

In April 2004, the United States removed Libya from the ILSA sanctions, following fulfillment of that country's commitments to rid itself of weapons of mass destruction and to renounce terrorism. On September 20, 2004, the President signed an executive order terminating the national emergency (declared in Executive Order 12543 of January 7, 1986), with respect to the policies and actions of the Government of Libya, revoking Executive Order 12544 of January 8, 1986 and Executive Order 12801 of April 15, 1992, all of which imposed sanctions against Libya in response to the national emergency. The new September 2004 executive order also revokes Executive Order 12538 of November 15, 1985, which prohibited the importation into the United States of petroleum products refined in Libya. This lifting of sanctions has opened the door to a potential return of U.S. oil companies to Libya for the first time in nearly 20 years.

Besides Iran, the United States maintains sanctions on two other oil producing nations - Sudan and Syria. For more information on these sanctions, please see EIA's Global Energy Sanctions report.

Natural Gas

U.S. natural gas production is expected to fall in 2005 due to Hurricanes Katrina and Rita. High prices should stimulate both production and imports during 2006.

As of December 31, 2004, EIA estimated that the United States had proven natural gas reserves of 192.5 trillion cubic feet (Tcf), or about 3 percent of world reserves (6th in the world). EIA forecasts U.S. natural gas consumption for 2005 at about 22.3 Tcf, with gross imports of 4.2 Tcf. More than 80 percent of U.S. natural gas imports come from Canada, mainly from the western provinces of Alberta, British Columbia, and Saskatchewan. Overall, the United States depends on natural gas for about 22 percent of its total primary energy requirements (oil accounts for around 41 percent and coal for 23 percent).

Natural Gas Production and Storage

EIA's latest Short-Term Energy Outlook projects that U.S. domestic dry natural gas production in 2005 will decline by about 4 percent, due in large part to the major disruptions to infrastructure in the Gulf of Mexico from both Hurricanes Katrina and Rita. Dry gas production is projected to increase by 4.7 percent in 2006. EIA expects net imports of natural gas (pipeline and liquefied natural gas - LNG) to increase only slightly in 2005 (0.1 percent over 2004) but to increase by over 12 percent in 2006. Imports of LNG appear to have exhibited little change through the first half of 2005 compared to year-ago levels. High natural gas prices in other world markets during the first three quarters of 2005 have served to attract available supplies of LNG that might otherwise have been directed to the United States, although fourth quarter imports are estimated to increase in response to high U.S. prices. Currently, total LNG imports for 2005 are projected to be approximately 650 Bcf in 2005 and just over 1,000 Bcf in 2006, compared to 650 Bcf in 2004.

In the near- to medium-term, EIA expects increases in natural gas production to come mainly from lower 48 sources. Increased use of cost-saving technologies is expected to result in continuing large natural gas finds, including in the deep waters of the Gulf of Mexico but also in onshore fields. In the longer term, Alaska's North Slope fields represent a large potential natural gas source, with an estimated 30-35 Tcf of natural gas resources. Getting the gas to market is the main challenge. One possibility is a $20 billion natural gas pipeline running 3,500 miles from the North Slope along the Alaska Highway into Alberta and on to markets in the U.S. Midwest. In October 2004, Congress promised to cover 80 percent of the project's cost if it were to go bankrupt. Still, the project is considered risky by major energy companies, and it remains uncertain whether or not the project will move ahead.

EIA estimates that working gas in storage as of November 4, 2005 was 3,229 Bcf, which is 123 Bcf (4 percent) above the 5-year average inventory level. Although natural gas storage remains above the 5-year average, the double blows of Hurricanes Katrina and Rita reduced the peak storage achievable over the remainder of the injection season from what was expected previously. Expected working gas in storage at the end of the fourth quarter is expected to be about 2.5 Tcf, 200 Bcf below year-ago levels and about 50 Bcf above the 5-year average.

As of 2003, top natural-gas-producing states (in descending order) included Texas, New Mexico, Oklahoma, Wyoming, Louisiana, Colorado, Alaska, Kansas, Alabama and California.

Natural Gas Demand

U.S. natural gas consumption has grown rapidly the past 15 years, but fell slightly in 2005 on sharply higher prices.

From 1990 through 2004, according to EIA, natural gas consumption in the United States increased by about 16 percent. EIA's latest Short-Term Energy Oulook projects that total natural gas demand will fall by 0.8 percent in 2005, due mainly to higher prices and Hurricanes Katrina and Rita, In 2006, natural gas consumption is expected to recover by 2.8 percent due to an assumed return to normal weather. In addition, a rebound in industrial activity is expected to increase natural gas demand in that sector by about 6 percent over 2005 levels. Natural gas is consumed in the United States mainly in the industrial (38 percent), electric power (24 percent), residential (22 percent), and commercial (13 percent) sectors.

U.S. natural gas consumption and imports are expected to expand substantially in coming decades, with the fastest volumetric growth resulting from additional natural-gas-fired electric power plants. Increased U.S. natural gas consumption will require significant investments in new pipelines and other natural gas infrastructure. New LNG terminals are projected to start coming into operation in 2006, and net LNG imports are expected to increase to 6.4 trillion cubic feet in 2025. Net imports of natural gas from Canada are projected to decline from 3.0 trillion cubic feet in 2005 to 2.5 trillion cubic feet in 2009, rise again to 3.0 trillion cubic feet in 2015, and then decline to 2.5 trillion cubic feet in 2025.

Domestic and Import Pipelines

With U.S natural gas demand growing rapidly, expansion of pipeline networks will be necessary in coming years. In recent years, several natural gas pipelines have come online.

At the close of 2004, the U.S. natural gas transportation network included more than 200 mainline natural gas pipeline systems. Combined, these 107 interstate systems and more than 90 non-interstate systems account for over 297,000 miles of pipeline. Moreover, the interstate network represents approximately 148 Bcf/d of natural gas transportation capacity while the non-interstate pipelines account for at least 30 Bcf/d. During 2004, total U.S. natural gas pipeline system mileage increased by less than 1 percent while overall system capacity increased by slightly more than 4 percent.

Expansion of the U.S. natural gas transmission network slowed in 2004, both in terms of added transportation capacity and new pipeline mileage. Only about 1,450 miles of pipeline and 7.7 Bcf/d of natural gas pipeline capacity were added to the national gas transmission grid during 2004, compared with 2,243 miles and 10.4 Bcf/d of capacity in 2003. The amount of incremental capacity in 2004 was the least since 1999 when only 6.5 Bcf/d was added. During 2004, six new pipeline systems were placed in operation in the deepwater Gulf of Mexico, plus the 560-MMcf/d Cheyenne Plains Pipeline, and a 320-MMcf/d expansion of the southern leg of the El Paso Natural Gas pipeline system.

In the past few years, several major natural gas pipelines came online: the Gulfstream Pipeline, 1,130 MMcf/d–560 miles, which carries natural gas under the Gulf of Mexico from gas-processing facilities located on the Gulf coasts of the States of Mississippi and Alabama to west central Florida; the North Baja Pipeline, 500 MMcf/d–80 miles (in the U.S.), which exports gas to electric power plants located in Baja California, Mexico; the Questar Southern Trails Pipeline, 87 MMcf/d–405 miles, which transports gas from the four corners area of New Mexico/Utah (San Juan Basin) to the California/Arizona border area; and the Guardian, 750 MMcf/d–142 miles, and Horizon, 380 MMcf/d—29 miles, pipelines, which expanded the flow of gas supplies between the Chicago hub and the growing market of northern Illinois and southern Wisconsin. On December 1, 2000, the $2.9 billion, 1.3-Bcf/day Alliance Pipeline from western Canada (Fort St. John, British Columbia) to the Chicago area entered service.

Columbia Gas System's Millennium project ($700 million), which is to connect Canadian natural gas sources to New York and Pennsylvania, received FERC go-ahead on September 19, 2002. Current plans are for Phase I of the Millennium line to be in service by November 2006, although the project has yet to be approved by FERC in its revised form. The second phase is currently on hold until 2008 or later owing to increased competition and a changed market in the New York City metropolitan area. If it is completed, Millennium will transport up to 714 MMcf/d of natural gas, providing an environmentally preferred option for generating electricity. According to the Millennium Pipeline consortium's web site, more than 90 percent of the pipeline's 425-mile overland route uses existing utility corridors, with about 224 miles of the project replacing and upgrading a 50-year-old pipeline system owned and operated by Columbia Gas Transmission Corp.

Growing U.S. demand for Canadian natural gas has been a dominant factor underlying many of the pipeline expansion projects this decade. The U.S. and Canadian natural gas grids are highly interconnected and Canadian natural gas has become an increasingly important component of the total natural gas supply for the United States. This is especially true for certain U.S. regions such as the Northeast, Midwest, the Pacific Northwest and California, which depend on Canadian natural gas for significant amounts of their supply. Overall, the United States received about 3.6 Tcf of natural gas (gross) from Canada during 2004, up from 3.5 Tcf in 2003. Mexico is a small net importer of natural gas from the United States.

Considerable progress has occurred in recent years to connect Canadian natural gas supplies to U.S. consumers. The Northern Border Pipeline, an extension of the Nova Pipeline, came onstream in late 1999 and connects to Chicago through the upper Midwest. A further extension to Indiana entered service in 2001. The Maritimes and Northeast Pipeline came onstream in January 2000, running from Sable Island to New England, with further extensions into the Boston area to be completed during 2003. The pipeline has a capacity of 400 MMcf/d.

The $2.5 billion Alliance Pipeline, at 1,875 miles, is the longest pipeline ever built in North America, and is designed to carry about 1.3 Bcf/d of gas from western Canada (Fort St. John, British Columbia) to the Chicago area. The pipeline began commercial service on December 1, 2000. The U.S. utility Pacific Gas & Electric imports natural gas from British Columbia via the Alliance pipeline.

Another possibility for future U.S. natural gas supplies lies in northern Canada, which contains around one third of that country's recoverable gas reserves. The Mackenzie Valley pipeline, for instance, could carry as much as 1.2 Bcf/d of gas from Canada's far north to southern Canada and the United States, possibly beginning in 2008 (assuming satisfactory completion of a regulatory and environmental review; currently, the project appears stalled). However, Canada is consuming increasing volumes of gas itself for such activities as oil sands extraction and processing. Accordingly, Canada may export less natural gas to the United States than is now expected. A competing pipeline would transport natural gas from Alaska's North Slope to the lower-48 states, with possible capacity as high as 4-5 Bcf/d, potentially beginning sometime around 2012.

On October 12, 2001, the U.S. Coast Guard lifted a ban on LNG tankers from Boston harbor. The ban, in effect starting September 26, 2001 (two weeks after the terrorist attacks in New York and Washington, DC), was established in response to security and safety concerns about the ships that bring LNG to the import facility of Distrigas of

Massachusetts (a Division of Tractebel, Inc.). The decision enabled the reopening of the Distrigas facility in Everett, Massachusetts, one of five currently active LNG facilities in the United States (plus one in Puerto Rico). The other four active U.S. LNG facilities are located in Lake Charles, Louisiana; Elba Island, Georgia; Cove Point, Maryland, which received its first commercial LNG cargo in 23 years in August 2003; and offshore Louisiana (the Gulf Gateway Energy Bridge deepwater port, operational since March 2005). Cove Point is now the nation's largest LNG import facility, and a new 2.5-Bcf storage tank is scheduled to be added in January 2005 by its owner, Dominion. Expansion is also planned for the Lake Charles and Elba Island LNG facilities.

On balance, interest is growing in LNG as a source of natural gas for U.S. electric power generation and also as a source that would provide supply flexibility. EIA expects that net LNG imports to the United States will increase sharply in coming years, growing to 2.5 Tcf in 2010 and 6.4 Tcf in 2025. During 2004, the United States received about 652 Bcf of LNG, mainly from Trinidad and Tobago, Algeria, and Qatar.

Currently, about 55 LNG terminals are on the drawing board to serve North America (mainly the United States). The Sempra Energy Cameron LNG project in Hackenberry, LA, approved in September 2003 by the Federal Energy Regulatory Commission (FERC), marked the first new LNG plant granted approval in the United States in 25 years. Besides the Hackenberry facility, Sempra signed a deal with BP in December 2003 to supply Indonesian LNG to a proposed receiving terminal in Baja California. The gas would then be piped to U.S. West Coast markets. Also, in December 2003, Shell announced plans to build a $700 million LNG receiving terminal, called Gulf Landing, 38 miles off the coast of Louisiana. The project is slated to handle 1 Bcf/d of LNG starting in 2008 or 2009. Other possible LNG projects include: an offshore LNG receiving terminal called Port Pelican, located 40 miles off the Louisiana coast (ChevronTexaco); a $600 million facility near Port Arthur, Texas (ExxonMobil); a terminal in Sabine Pass, LA (Cheniere LNG) approved by FERC in March 2005; and a $450 million terminal in eastern Mississippi (Gulf LNG Energy).

In December 2003, EIA issued a report, "The Global Liquefied Natural Gas Market: Status and Outlook," in conjunction with a Department of Energy LNG summit. At the summit, then-Energy Secretary Spencer Abraham pledged to make the process of licensing and building LNG receiving terminals easier. In March 2004, an agreement between FERC, the Coast Guard, and the Department of Transportation aims at streamlining the process regarding environmental, safety, and security reviews of proposed LNG projects.

Natural Gas Prices

The Henry Hub natural gas spot price averaged over $12 per mcf in September 2005 on increased cooling demand, higher crude oil prices, and Hurricane Katrina.

Natural gas wellhead prices reached then-record highs of nearly $10.00 per thousand cubic feet (mcf) in late 2000/early 2001, but fell sharply soon thereafter to around $2.50 per mcf. Cold weather in the U.S. Northeast and Midwest during the winter of 2002/2003 raised prices once again, as gas storage levels hit unusually low levels and cold weather limited pipeline operations. The Henry Hub natural gas price is expected to average about $9.15 per mcf in 2005 and $9.00 per mcf in 2006. In September 2005, the Henry Hub natural gas spot price averaged $12.40 per mcf, as hot weather in the East and Southwest increased natural gas-fired electricity generation for cooling demand, crude oil prices increased, and Hurricane Katrina hit.

Coal

U.S. coal production was up in 2004 and the first 8 months of 2005; Western U.S. accounts for 55% of U.S. coal output.

The United States produced 1,112 million short tons (Mmst) of coal in 2004, up 3.7 percent from 2003 output, after two straight years of declining output. During the first nine months of 2005, coal production increased 1.1 percent year-over-year. Led by Wyoming (201 Mmst of production in the first half of 2005), the Western half of the country accounts for about 55 percent of the U.S. total, overwhelmingly from surface mines. Appalachia (led by West Virginia and Kentucky) accounts for about 35 percent of total U.S. coal production, mainly from underground mines. About three-fifths of U.S. coal production is bituminous, one-third subbituminous, and about one-tenth lignite (brown coal).

Around 70,000 miners work in the U.S. coal industry (55,000 in the East, 16,000 in the West), down from a peak of 700,000 in 1923, when U.S. coal production was half what it is today. Major U.S. coal companies include Peabody Energy (the largest in terms of production), Arch Coal (the second largest coal producer); and Kennecott Energy.

Coal production in the Appalachian Region increased in 2004 to a total of 390.7 Mmst, after reaching 25-year low in 2003. Although there was an increase in total coal production in the region in 2004, the Appalachian Region has not experienced 3 consecutive years of coal production of less than 400 Mmst since the early 1970s.

Although the Appalachian Region produced more coal in 2004, the production level was still constrained by several factors. Transportation problems affected the amount of coal moved to markets. Railroads experienced numerous delays and barge shipments were curtailed due to river flooding, lock maintenance, and blocked river locks due to sunken barges. The combination of reserve degradation in the region along with the legacy of past lawsuits that had temporarily halted the issuance of needed permits to open new mines or to expand current operations, continued to constrain the amount of coal produced. Geological and equipment problems added to the limitations in coal production in some Appalachian States. Declining productivity and increasing operating costs also contributed to the constrained production levels in the region. However, all but two states in the region had higher production levels in 2004 and the declines that were experienced in those two states were slight.

During 2005, coal production is expected to rise slightly in Appalachia and in the U.S. interior, and increase strongly in the West. In 1998, low-sulfur western coal production surpassed relatively higher-cost, higher-sulfur, Appalachian coal for the first time, following strong increases since 1994, prompted largely by Phase 1 of the CAAA (1990). CAAA originally took effect during 1995, and required lower sulfur emissions from coal combustion. In response, Wyoming increased its coal production sharply, particularly low-sulfur, low-ash (and low cost) coal from the Powder River Basin, where coal is strip-mined.

Recurring problems in the coal industry had varying impacts on coal production in 2004. At issue in 2004 were transportation of coal from mines to consumers; weather; environmental concerns; legal challenges; and global economics. Transportation of coal from the mine to the consumer continues to be an issue for the industry. Most coal in the U.S. is moved by railroads exclusively or in tandem with another method of transportation. In 2004, major railroads experienced record levels of commodities moving around the Nation and as a result, bottlenecks were experienced across the country causing delays in coal deliveries to several utilities throughout the year. Flooding on the major waterways, along with river lock repairs and sunken barges also contributed to the transportation problems. Four hurricanes hit the United States in 2004, causing numerous problems for the coal industry including flooding, disruptions in deliveries, off-line power plants, and the inability of employees to get to the mines in southeastern coal-producing States. Several of the legal challenges concerning mining permits and the levels of environmental review needed to obtain them still have not been settled. The wide-ranging economic expansion experienced in China in 2004 drove world markets for many commodities into overdrive and helped to reestablish the United States into Asian coal markets.

U.S. coal consumption reached a record in 2004 as the economy and electric power generation both increased. Coal prices also increased in 2004.

The continuing economic recovery in 2004 pushed total U.S. coal consumption to another record level. Preliminary data show that total coal consumption increased 9.4 Mmst to reach a level of 1,104.3 Mmst, an increase of 0.9 percent. The electric power sector (electric utilities and independent power producers) accounted for almost 92 percent of all coal consumed in the United States in 2004. The other coal-consuming sectors (other industrial, coking coal, and residential and commercial sectors) had minor changes in their consumption totals. The other industrial sector had almost the same level of coal consumption in 2004 as in 2003, while the coking coal sector had a decrease of 2.4 percent. The residential and commercial sector, the smallest of all coal consuming sectors -- accounting for less than one half of one percent of total consumption -- remained at the same level in 2004. Coal consumption in the electric power sector increased by 10.0 Mmst to end 2004 at a record level of 1,015.1 Mmst

Coal prices rose across the board in 2004. While spot coal prices for some of the producing regions set record levels in 2004, average delivered prices in the consuming sectors increased for the year but not as steeply as the spot prices. Due to the fact that coal deliveries to the electric power sector are mostly done through long-term contracts, the delivered price of coal to the electric power sector increased in 2004, but not by huge amounts. According to preliminary data through November 2004, coal prices at electric utilities (a subset of the electric power sector) increased for a fourth consecutive year, to $27.28 per short ton (1.34 dollars per million Btu), an increase of 6.0 percent. Coal prices at independent power producers increased in 2004 to $27.18 per short ton (1.40 dollars per million Btu), but were still lower that the 2002 price of $27.96 per short ton, which was the first year the price data was available for publication. The increase in the delivered price of coal to the other sectors in 2004 was more evident as both the coking coal sector and the other industrial sector rely more heavily on short-term contracts and the spot market. The average delivered price of coal to the other industrial sector increased by 13.2 percent to an average price of $39.30 per short ton in 2004. The largest increase in consumer prices was in the coking coal sector.

The electric power sector, made up of electricity producers whose primary business is producing power for public distribution, accounts for the vast majority (over 90 percent) of U.S. coal consumption, with coke plants and "other industrial" accounting for most of the remainder. In coming years, as sulfur dioxide emissions standards are tightened (in 2000, for instance, Phase 2 of the Clean Air Act Amendments, CAAA, took effect), the share of low-sulfur coal (mainly from the western U.S.) in the country's coal consumption mix is expected to increase. In 2002, production of medium- and high-sulfur coal was 578 Mmst (52 percent), while low-sulfur coal output was 527 Mmst (48 percent). By 2025, medium- and high-sulfur coal is expected to make up just 43 percent of total U.S. coal output, with low-sulfur coal accounting for 57 percent of the total.

U.S. gross coal exports fell sharply starting in the mid-1990s due mainly to lower world coal prices and increased competition from other coal-producing nations (i.e., Australia, South Africa, China, Venezuela, Colombia), as well as from natural gas -- especially in Europe. In 2004, U.S. coal exports increased for the second year, to 48 Mmst, but were still slightly below the 2001 level. In coming years, the U.S. coal industry is expected to continue to face strong competition from other coal-exporting countries, with limited or negative growth in import demand in Europe and the Americas. The continued rise in U.S. gross coal imports is partly attributable to heightened demand for low-sulfur coal, and in part to the need to meet stricter sulfur emission requirements of Phase 2 of the CAAA. U.S. coal imports set another record level in 2004. Total coal imports were 27.3 Mmst, an increase of 8.9 percent, or 2.2 Mmst.

Electricity

U.S. electricity demand is increasing, as are prices.

In 2004, the United States generated 3,953 billion kilowatthours (Kwh) of electricity, including 3,794 billion Kwh from the electric power sector plus an additional 152 billion Kwh coming from combined heat and power (CHP) facilities in the commercial and industrial sectors. For the electric power sector, coal-fired plants accounted for 52 percent of generation, nuclear 21 percent, natural gas 16 percent, hydroelectricity 7 percent, oil 3 percent, geothermal and "other" 1 percent. During the first half of 2005, electric power generation was about flat year-over-year.

Natural gas-fired power generation has greatly increased its share of the U.S. power mix over the past few years, from just 9 percent in 1988 to 18 percent in 2004. Investment in coal-fired power generation generally has been less attractive than natural gas in recent years due to relatively high capital costs and longer construction periods. As a result, coal's share in the U.S. power mix has fallen from 57 percent in 1988 to 50 percent in 2004. The share of nuclear power generation in the U.S. power mix has remained relatively flat over the past 15 years or so, increasing slightly from 19 percent in 1988 to 20 percent in 2004. Oil's share has fallen from 5 percent in 1988 to 3 percent in 2004.

On a national level during 2004, the retail price of electricity averaged 7.57 cents per Kwh, up 2.0 percent from 7.42 cents per Kwh in 2003. Electricity prices in the United States fell every year between 1993 and 1999, but this trend reversed in 2000. For the first six months of 2005, electricity prices were up 4.2 percent year-over-year, to 7.69 cents per Kwh.

As of January 1, 2004, U.S. net summer electric generating capacity was 948 gigawatts (GW). Of this total, 77 percent was thermal (33 percent coal, 22 percent natural gas, 18 percent "dual-fired," 4 percent petroleum), 10 percent hydro, 10 percent nuclear, and 2 percent "other renewables" (geothermal, solar, wind). The amount and geographical distribution of capacity by energy source is a function of, among other things, availability and price of fuels and/or regulations. Capacity by energy source generally shows a geographical pattern such as: significant nuclear capacity in New England, coal in the central U.S., hydroelectric in the Pacific West, and natural gas in the Coastal South.

Total U.S. annual electricity demand grew about 1.7 percent during 2004. For the first seven months of 2005, electricity demand increased about 1.9 percent year-over-year, driven by accelerated growth in the economy and weather-related increases in the first and the fourth quarters. Overall, electricity demand is expected to increase by 3.3 percent in 2005 and about 1.3 percent in 2006 due largely to weather conditions as well as continuing economic growth.

On August 14, 2003, a huge electric power blackout hits large parts of the northeastern United States, the Midwest, and southern Canada late in the afternoon. Power was knocked out for at least several hours in major cities like New York, Detroit, Cleveland, and Toronto. Three months later (November 2003), the U.S.-Canada Power System Outage Task Force, led by U.S. Secretary of Energy Spencer Abraham and Canadian Natural Resource Minister Herbert Dhaliwal, released a 124-page investigative report which concluded that the blackout was "largely preventable" and cited several failures by regional utility companies and regulators. Analyses of the blackout also were completed by the Michigan Public Service Commission and the Electric Power Research Institute (EPRI).

At present, electric power trade between Mexico and the United States is severely limited by infrastructure constraints, including inadequate power transmission capability (there are only three cross-border transmission lines, two between El Paso and Ciudad Juarez and one between Brownsville and Matamoros). In January 2001, a small (50-MW), natural-gas-fired power plant in Baja California began exporting power to California. Canada exported about 30 billion Kwh of electricity to the United States in 2003, mostly from Quebec, Ontario, and New Brunswick to New England and New York. Smaller volumes are exported from British Columbia and Manitoba to Washington state, Minnesota, California, and Oregon. Considerable reciprocity exists between Canadian and U.S. power markets, as the United States also exports smaller volumes of electricity to Canada.

Nuclear

In 2004, U.S. nuclear power accounted for about 20 percent of total U.S. electricity generation, second only to coal in the U.S. electricity generation mix. Nearly 40 percent of U.S. nuclear output was generated in just five states: Illinois, Pennsylvania, South Carolina, North Carolina, and New York. The average utilization rate for all nuclear units nationwide increased from 66.0 percent in 1990 to 90.3 percent in 2002, an all-time record high. Following the September 11, 2001 terrorist attacks on the United States, security at nuclear power plants around the United States was increased dramatically.

Nuclear power in the United States grew rapidly after 1973, when only 83 billion kWh of nuclear power were produced. By 2004, nuclear power output had increased nine-fold, with 104 licensed nuclear power units (69 pressurized water reactors and 35 boiling water reactors) generating 789 billion kWh of electricity. This rapid growth in nuclear power generation, however, obscures serious underlying problems in the U.S. nuclear industry. After 1974, many planned units were canceled, and since 1977, no orders have been placed for new nuclear units, and none are currently planned. The 1979 Three Mile Island accident greatly increased concerns about the safety of nuclear power plants in the United States. The regulatory reaction to those concerns contributed to the decline in the number of planned nuclear units, with Watts Bar I (1996) the last plant completed. In late March 2000, the Nuclear Regulatory Commission (NRC), in a positive signal to the U.S. nuclear power industry, granted the first-ever renewal of a nuclear power plant's operating license. The 20-year extension (until 2034 and 2036 for two reactors) went to the 1,700-MW Calvert Cliffs plant in Maryland.

On July 9, 2002, the U.S. Congress voted to formally approve Yucca Mountain, located 100 miles north of Las Vegas, as the nation's permanent nuclear waste depository (on December 2, 2003, President Bush signed a $27.3 billion energy and water bill that included funding for the Yucca Mountain facility). Studies on Yucca Mountain as a possible nuclear waste site have been going on for over two decades, with concerns centering on the dangers of transporting nuclear materials to the site via rail or highway. Nuclear utilities have complained that they are running out of nuclear waste storage capacity at their nuclear plants, with many being forced to resort to "dry cask" storage of spent fuel assemblies after water-storage pools reached capacity. The repository also remains a source of controversy between state and federal officials. In February 2002, Nevada Governor Kenny Guinn indicated that he would oppose the project, making congressional approval necessary for Yucca Mountain to go forward. The site's selection is also being challenged in Federal Appeals court by the state of Nevada. Overall, the project is expected to cost $40 to $50 billion and be able to store 77,000 tons of radioactive waste. In November 2004, Congress cut funding for the Yucca Mountain program by $303 million in fiscal year 2005, possibly delaying the facility's opening by several years.

Hydroelectricity/Other Renewables

During 2004, the United States consumed 6.1 quadrillion Btu of renewable energy, about 6 percent of total domestic gross energy demand, with the largest component used for electricity production. As of October 2005, 20 states had adopted renewables portfolio standards (RPS) or mandates aimed at increasing the share of renewable power in the energy mix. Several other states are considering adoption of RPS, while others with RPS already in place are looking for ways to accelerate the development of renewables. Growth in renewable energy continues to be challenged by little or no development of new hydroelectric sites, a slow but lengthy decline in the use of biomass for non-electric purposes, and the high capital costs of most renewable energy production facilities, relative to fossil-fueled alternatives.

Overall, hydropower provided around 45 percent of total U.S. renewable production in 2004, with biofuels (including wood and waste), solar, wind, and geothermal making up most of the remainder. Total hydropower generation fell by around 3.5 percent during 2004 compared to 2003. During the first half of 2005, about 63 percent of U.S. hydroelectric output was supplied by just four states: Washington, California, and Oregon on the Pacific coast, plus New York. For the first half of 2005, total hydropower generation was up 6.8 percent year-over-year.

Wind, solar, biomass, and geothermal power, although growing, continue to supply a tiny fraction of total U.S. energy needs. According to EIA's Annual Energy Outlook 2005, however, renewable power production is expected to grow by

1.5 percent per year between 2003 and 2025, the fastest growth rate of any domestic energy source. In 2003, shipments of solar PV cells and modules fell by 2 percent, to around 109 megawatts, according to EIA's Renewable Energy Annual 2003. The average unit price of PV cells decreased in 2003 by 12 percent, to $1.86 per peak watt. Total shipments of solar thermal collectors stayed roughly flat in 2003, at around 11 million square feet.

In 2004, the United States added 389 MW of wind power capacity, pushing the total to 6,740 MW, up more than four-fold from the 1,584 of wind capacity in 1992. This growth was significantly slower than the record growth of 1,694 MW seen in 2001 and 1,687 MW in 2003, according to the American Wind Energy Association (AWEA). For 2005, the AWEA estimates that the United States will add up to 2,500 MW of wind power capacity. By 2009, the AWEA expects that total installed wind power capacity in the United States could reach 15,000 MW.

Fluctuations in wind power capacity additions stem in part from the uncertain status of a key federal wind Production Tax Credit, or PTC, first established in 1992. The PTC expired on December 31, 2003, and was not renewed until September 2004. In July 2005, the PTC - which had been scheduled to expire at the end of 2005 - was renewed through 2007 at 1.9 cents per kWh. California, Texas, Minnesota, and Iowa currently are the top four states in terms of installed wind power capacity, while the largest wind farm is located on the Oregon-Washington state line.

The first U.S. offshore windmill park, with a peak capacity of 420 MW from 130 turbines, has been proposed for construction off the Cape Cod coast. The project (by Cape Wind) could power more than 200,000 homes in Cape Cod, but has been opposed by local residents who believe the project would mar the area's landscape. On November 9, 2004, the US Army Corps of Engineers (USACE) issued a draft environmental impact statement on the Cape Cod wind project, finding that the positives of the project outweighed any possible negatives.

Meanwhile, Iowa's largest utility (MidAmerican Energy) has announced plans for a 310-MW wind power facility, the country's largest to date. Both Cape Cod and Iowa are areas of the country considered to have significant wind energy potentials. Other large wind projects include the 240-MW Flat Rock Phase I project in New York, the 220-MW Wild Horse project in Washington, the 200-MW Forward Wind Power project in Wisconsin, and the 200-MW Fenton project in Minnesota.

Profile

Country Overview

Chief of State	President George W. Bush (since January 20, 2001; reelected November 2, 2004)
Location	North America, bordering both the North Atlantic Ocean and the North Pacific Ocean, between Canada and Mexico
Independence	July 4, 1776 (from Great Britain)
Population (2005E)	295,734,134
Languages	English 82.1%, Spanish 10.7%, other Indo-European 3.8%, Asian and Pacific island 2.7%, other 0.7% (2000 census)
Religion	Protestant 52%, Roman Catholic 24%, Mormon 2%, Jewish 1%, Muslim 1%, other 10%, none 10% (2002 est.)
Ethnic Group(s)	white 81.7%, black 12.9%, Asian 4.2%, Amerindian and Alaska native 1%, native Hawaiian and other Pacific islander 0.2% (2003 est.) note: a separate listing for Hispanic is not included because the US Census Bureau considers Hispanic to mean a person of Latin American descent (including persons of Cuban, Mexican, or Puerto Rican origin) living in the US who may be of any race or ethnic group (white, black, Asian, etc.)

Economic Overview

Exchange Rate per Dollar (10/18/2005)	British Pound (0.57009); Canadian Dollar (1.1793); Euro (0.83160); Japanese Yen (114.93)
Inflation Rate (2005E)	2.7%
Gross Domestic Product (2005E)	$11.8 trillion
Real GDP Growth Rate (2005E)	3.5%
Unemployment Rate (9/05E)	5.1%
Current Account Balance (2005E)	-$821 billion
Merchandise Exports (2005E)	$899 billion
Exports - Commodities	agricultural products (soybeans, fruit, corn) 9.2%, industrial supplies (organic chemicals) 26.8%, capital goods (transistors, aircraft, motor vehicle parts, computers, telecommunications equipment) 49.0%, consumer goods (automobiles, medicines) 15.0% (2003)
Exports - Partners (2004E)	Canada 23%, Mexico 13.6%, Japan 6.7%, UK 4.4%, China 4.3%
Merchandise Imports (2005E)	$1,681 billion

Imports - Commodities	agricultural products 4.9%, industrial supplies 32.9% (crude oil 8.2%), capital goods 30.4% (computers, telecommunications equipment, motor vehicle parts, office machines, electric power machinery), consumer goods 31.8% (automobiles, clothing, medicines, furniture, toys) (2003)
Imports - Partners (2004E)	Canada 17%, China 13.8%, Mexico 10.3%, Japan 8.7%, Germany 5.2%
Merchandise Trade Balance (2005E)	-$782 billion
Unified Federal Budget Balance (2005E)	-$319 billion

Energy Overview

Secretary of Energy	Samuel Bodman (since February 1, 2005)
Proven Oil Reserves (January 1, 2005E)	21.9 billion barrels
Oil Production (January-October 2005E)	7.5 million barrels per day, of which 5.4 million barrels per day was crude oil (Note: does not include “refinery gain”)
Oil Consumption (2005F)	20.8 million barrels per day
Net Oil Imports (2005F)	12.2 million barrels per day (59% of total consumption)
Crude Oil Imports from the Persian Gulf (January-July 2005E)	2.3 million barrels per day
Top Sources of U.S. Crude Oil Imports (January-July 2005E)	Canada (1.61 million bbl/d); Mexico (1.59 million bbl/d); Saudi Arabia (1.48 million bbl/d); Venezuela (1.29 million bbl/d); Nigeria (1.09 million bbl/d)
Value of Gross Oil Imports (January-July 2005E)	$130.1 billion
Crude Oil Refining Capacity (1/1/05E) (Oil and Gas Journal)	16.8 million barrels per day (132 refineries)
Total Oil Stocks (10/7/05)	1.69 billion barrels (including about 691 million barrels in the U.S. Strategic Petroleum Reserve)
Oil Wells Drilled (January-August 2005E)	5,087 (up from 4,722 during Jan.-Aug. 2004)
Operating Oil and Natural Gas Rotary Rigs in Operation (8/05E)	1,436 (1,227 for natural gas and 206 for oil)
Proven Natural Gas Reserves (January 1, 2005E)	189 trillion cubic feet
Natural Gas Production (2004E)	18.9 trillion cubic feet
Natural Gas Consumption (2004E)	22.4 trillion cubic feet
Gross Natural Gas Imports (2004E)	4.3 trillion cubic feet (85% from Canada)
Natural Gas Wells Drilled (2004E)	22,673 (up from 16,155 in 2002)
Recoverable Coal Reserves (2003E)	270.7 billion short tons
Coal Production (2004E)	1,105 million short tons
Coal Consumption (2004E)	1,102 million short tons
Gross Coal Exports (2004E)	48 million short tons
Primary and Secondary Coal Stocks (closing; 6/05E)	159 Mmst (down from198 Mmst in 5/03)
Electricity Net Summer Installed Capacity (2003E)	948 gigawatts (77% thermal-fired, 10% nuclear; 10% hydroelectric, and 2% "renewables")
Net Electricity Generation (2004E)	3,953 billion kilowatt hours

Electricity Consumption (2004E)	3,717 billion kilowatt hours
Total Energy Consumption (2004E)	100.3 quadrillion Btus*, of which Oil (40%), Natural Gas (23%), Coal (22%), Nuclear (8%), Hydroelectricity (3%), Other Renewables (1%)
Total Per Capita Energy Consumption (2003E)	339.9 million Btus
Energy Intensity (2003E)	9,568.5 Btu per $2000-PPP**

Environmental Overview

Administrator of the U.S. Environmental Protection Agency	Steve Johnson (since May 2, 2005)
Energy-Related Carbon Dioxide Emissions (2003E)	5,802.1 million metric tons, of which Oil (43%), Coal (36%), Natural Gas (21%)
Per-Capita, Energy-Related Carbon Dixoide Emissions (2003E)	20.0 metric tons
Carbon Dioxide Intensity (2003E)	0.6 Metric tons per thousand $2000-PPP**
Environmental Issues	Air pollution resulting in acid rain in both the US and Canada; the US is the largest single emitter of carbon dioxide from the burning of fossil fuels; water pollution from runoff of pesticides and fertilizers; limited natural fresh water resources in much of the western part of the country require careful management; desertification
Major Environmental Agreements	party to: Air Pollution, Air Pollution-Nitrogen Oxides, Antarctic-Environmental Protocol, Antarctic-Marine Living Resources, Antarctic Seals, Antarctic Treaty, Climate Change, Desertification, Endangered Species, Environmental Modification, Marine Dumping, Marine Life Conservation, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands, Whaling signed, but not ratified: Air Pollution-Persistent Organic Pollutants, Air Pollution-Volatile Organic Compounds, Biodiversity, Climate Change-Kyoto Protocol, Hazardous Wastes

Oil and Gas Industry

Major U.S. Oil Companies (2005; partial list)	Amerada Hess, Anadarko, Apache, BP, ChevronTexaco, CITGO, ConocoPhillips, ExxonMobil, Occidental, Marathon, Shell, Sunoco, Unocal, Valero, Williams
Major U.S. Coal Companies (2003; ranked by production)	Peabody Coal Co.; Kennecott Energy; Arch Coal.; RAG American Coal Holding; Consol
Oil Pipelines (2001E)	Around 2 million miles
Natural Gas Transmission Pipelines (2000E)	250,000 miles
Major Ports	Baltimore, Chicago, Hampton Roads, Houston, Los Angeles, New Orleans, New York, Philadelphia

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.
**GDP figures from OECD estimates based on purchasing power parity (PPP) exchange rates.

Links

EIA Links

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U.S. Government

CIA World Factbook - U.S.
U.S. Department of Energy's Office of Fossil Energy Home Page
U.S. Department of Energy: United States report
U.S. Department of Energy Home Page
U.S. Nuclear Regulatory Commission
Federal Energy Regulatory Commission
National Association of State Energy Officials
National Renewable Energy Laboratory (NREL)

Associations and Institutions
American Petroleum Institute
National Petroleum Council
Independent Petroleum Association of America
Petroleum Marketers Association of America
National Petroleum Refiners Association
American Gas Association
National Mining Association
Electric Power Research Institute
Edison Electric Institute
North American Electric Reliability Council
Nuclear Energy Institute
Global Climate Coalition
Resources for the Future
Export Council for Energy Efficiency
Alliance to Save Energy
American Solar Energy Society
Solar Energy Industries Association
American Wind Energy Association
Geothermal Energy Association
American Bioenergy Association

Sources

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Christian Science Monitor
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Financial Times
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Houston Chronicle
Los Angeles Times
Megawatt Daily
New York Times
Oil and Gas Journal
Oil Daily
Petroleum Intelligence Weekly
Pipeline and Gas Journal
Platts Oilgram News
PR Newswire
Reuters
U.S. Energy Information Administration (numerous publications -- see links)
USA Today
Washington Post
Weekly Petroleum Argus
World Gas Intelligence
World Markets Online
World Oil.

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