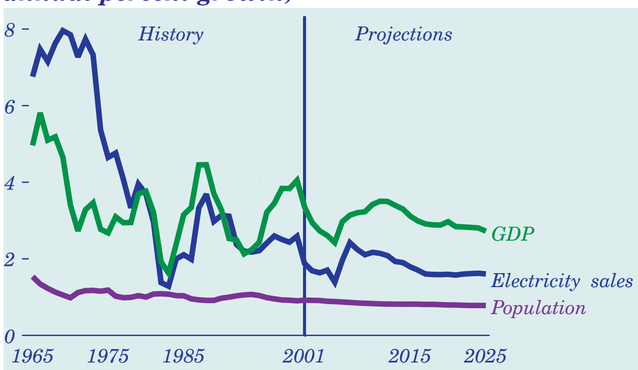
Electricity Use Is Expected To Grow More Slowly Than GDP

Figure 60. Population, gross domestic product, and electricity sales, 1965-2025 (5-year moving average annual percent growth)



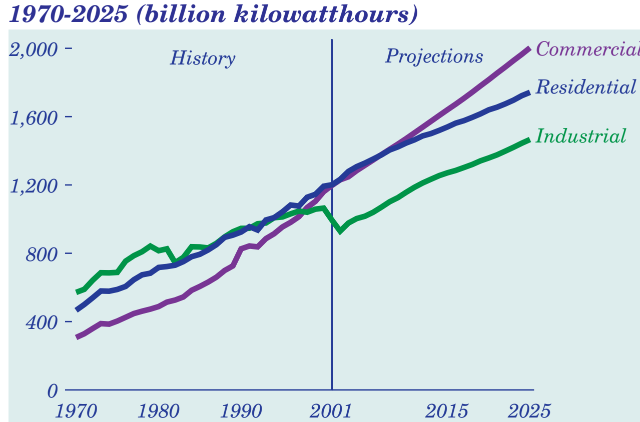
As generators and combined heat and power plants adjust to the evolving structure of the electricity market, they face slower growth in demand than in the past. Historically, demand for electricity has been related to economic growth; that positive relationship is expected to continue, but the ratio is uncertain.

During the 1960s, electricity demand grew by more than 7 percent per year, nearly twice the rate of economic growth (Figure 60). In the 1970s and 1980s, however, the ratio of electricity demand growth to economic growth declined to 1.5 and 1.0, respectively. Several factors have contributed to this trend, including increased market saturation of electric appliances, improvements in equipment efficiency and utility investments in demand-side management programs, and more stringent equipment efficiency standards. Throughout the forecast, growth in demand for office equipment and personal computers, among other equipment, is offset by slowing growth or reductions in demand for space heating and cooling, refrigeration, water heating, and lighting. The continuing saturation of electric appliances, the availability and adoption of more efficient equipment, and promulgation of efficiency standards are expected to hold the growth in electricity sales to an average of 1.8 percent per year between 2001 and 2025, compared with 3.0-percent annual growth in GDP.

Changing consumer markets could mitigate the slowing of electricity demand growth seen in these projections. New electric appliances are introduced frequently. If new uses of electricity are more substantial than currently expected, they could offset some or all of the projected efficiency gains.

Continued Growth in Electricity Use Is Expected in All Sectors

Figure 61. Annual electricity sales by sector, 1970-2025 (billion kilowatthours)



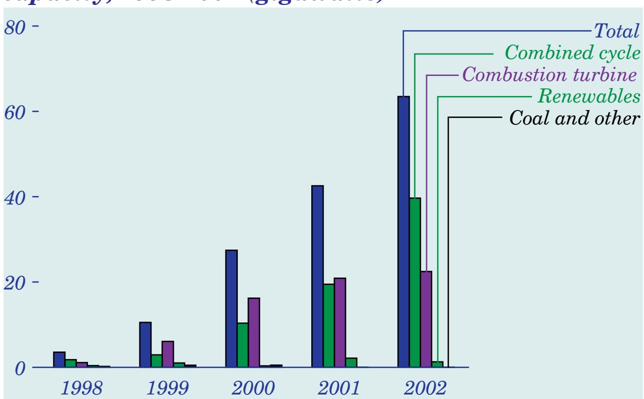
With the number of U.S. households projected to rise by 1.0 percent per year between 2001 and 2025, residential demand for electricity is expected to grow by 1.6 percent annually (Figure 61), a slower rate than in the recent past. Residential electricity demand changes as a function of the time of day, week, or year. During summer, residential demand peaks in the late afternoon and evening, when household cooling and lighting needs are highest. This periodicity increases the peak-to-average load ratio for local utilities, which rely on quick-starting gas turbines or internal combustion engines to meet peak demand. Twenty gigawatts of peaking capacity was added in 2001, and an additional 28 gigawatts is expected by 2003. Peaking capacity from natural gas turbines and internal combustion engines is projected to increase steadily to 179 gigawatts in 2025.

With continued growth in commercial and industrial electricity demand between 2001 and 2025 (2.2 and 1.6 percent per year, respectively), significant additions of baseload generating capacity are projected. Projected growth in commercial floorspace of 1.5 percent per year and growth in industrial shipments of 2.6 percent per year contribute to the expected increase.

In addition to sectoral sales, combined heat and power plants in 2001 produced 137 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. By 2025, their own-use generation is expected to increase to 212 billion kilowatthours as the demand for manufactured products increases.

Recent Surge in Capacity Additions Is Expected To Meet Near-Term Needs

Figure 62. Additions to electricity generating capacity, 1998-2002 (gigawatts)



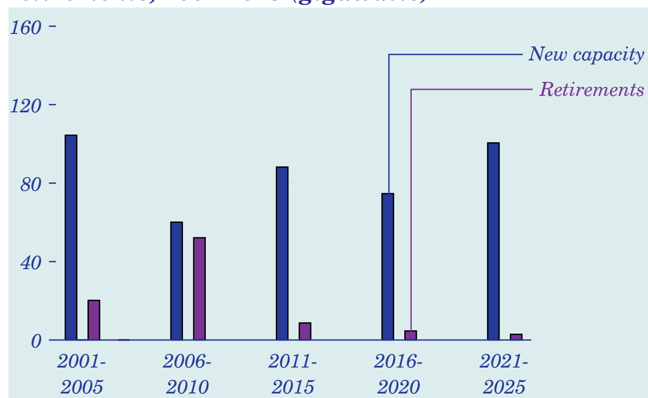
From 1960 to 1969, U.S. power suppliers brought 180 gigawatts of new generating capacity on line—an average of 18 gigawatts per year—and over the next 5 years, from 1970 to 1974, the pace doubled to an average of 36 gigawatts per year. Nearly 314 gigawatts of new capacity was brought on between 1970 and 1979, almost 75 percent more than in the previous 10 years. New capacity additions slowed to 172 gigawatts in the 1980s and 84 gigawatts in the 1990s, and by the mid- to late 1990s many regions of the country needed or were close to needing new capacity in order to meet consumer requirements reliably.

In 2001 and 2002, higher wholesale electricity prices sent strong signals to power plant developers that supplies were tightening, and they embarked on a dramatic building campaign. Although they had not built 20 gigawatts of new capacity in a single year since 1985, they built 27 gigawatts in 2000 and 43 gigawatts in 2001 and are on pace to build 62 gigawatts in 2002 (Figure 62)—by far the most ever built in a single year in the United States. More recently, developers have reported that they are delaying or canceling plants they were planning to build, and new additions are expected to slow in the near term.

Most of the recent additions are natural-gas-fired. Of the 144 gigawatts added between 1999 and 2002, 138 gigawatts is natural-gas-fired, including 72 gigawatts of efficient combined-cycle capacity and 66 gigawatts of combustion turbine capacity, which is used mainly when demand for electricity is high. Only about 5 gigawatts of new renewable plants—mostly wind—and less than 1 gigawatt of new coal-fired capacity were added over the same period.

Retirements and Rising Demand Are Expected To Require New Capacity

Figure 63. Projected new generating capacity and retirements, 2001-2025 (gigawatts)



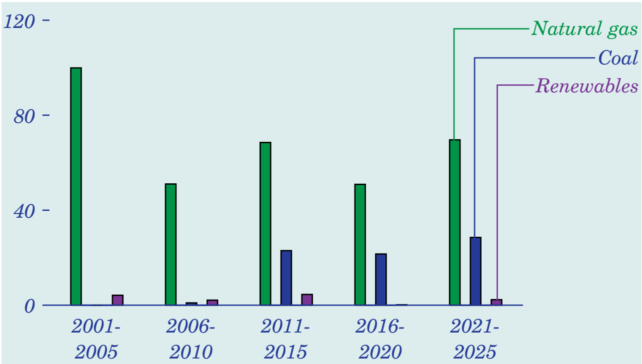
From 2001 to 2025, 428 gigawatts of new generating capacity (excluding combined heat and power plants) is expected to be needed to meet growing demand and to replace retiring units (Figure 63). Between 2001 and 2025, 3 gigawatts (3 percent) of current nuclear capacity and 79 gigawatts (13 percent) of current fossil-fueled capacity [*41*] are expected to be retired, including 56 gigawatts of oil- and natural-gas-fired steam plants. Nearly all the retirements are expected before 2010. Of the 164 gigawatts of new capacity expected by 2010, 30 percent is projected to replace retired oil- and natural-gas-fired steam capacity.

Because of their favorable economics, combined-cycle units are projected to be used for most new requirements. Efficiencies for combined-cycle units are expected to approach 54 percent by 2010, compared with 47 percent for coal-steam units, and the expected construction costs for combined-cycle units are only about 44 percent of those for coal-steam plants. As a result, about one-half (47 percent) of the projected combined-cycle additions are expected by 2010. As natural gas prices rise later in the forecast, new coal-fired capacity is projected to become more competitive, and 91 percent of the projected additions of new coal-fired capacity are expected to be brought on line from 2010 to 2025.

Only a few older, higher cost nuclear power plants, about 3 percent of current operating capacity, are expected to be retired by 2025. Planned capacity expansions at existing nuclear units are expected to raise net nuclear capacity slightly, from 98.2 gigawatts in 2001 to 99.6 gigawatts in 2025.

Natural Gas Units Are Expected To Dominate New Capacity Additions

Figure 64. Projected electricity generation capacity additions by fuel type, including combined heat and power, 2001-2025 (gigawatts)

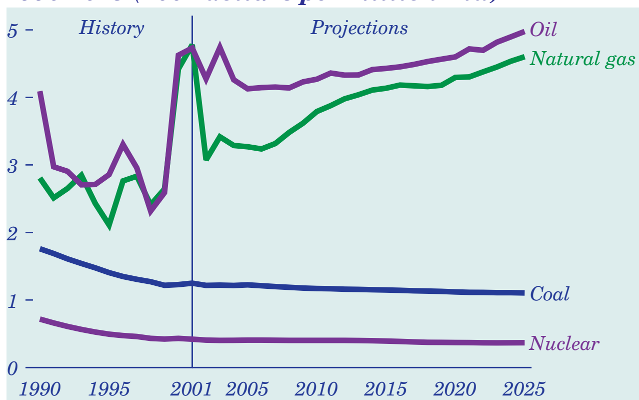


The electric power industry has added capacity at unprecedented speed over the past 2 years, and that trend is expected to continue through 2003. Even so, a total of 428 gigawatts of capacity (excluding combined heat and power plants) is projected to be needed by 2025 to meet growing demand and to offset retirements. Of the new capacity, 80 percent is projected to be natural-gas-fired combined-cycle or combustion turbine technology, including distributed generation capacity (Figure 64). These technologies are designed primarily to supply peak and intermediate capacity, but combined-cycle technology can also be used to meet baseload requirements.

A total of 74 gigawatts of new coal-fired capacity is projected to come on line between 2001 and 2025, accounting for almost 17 percent of all the capacity expansion expected. Competition with low-cost gas-turbine-based technologies and the development of more efficient coal gasification systems have compelled vendors to standardize designs for coal-fired plants in an effort to reduce capital and operating costs in order to maintain a share of the market. Renewable technologies account for 3 percent of expected capacity expansion by 2025—primarily wind, geothermal, and municipal solid waste units. About 16 gigawatts of distributed generation capacity is projected to be added by 2025, as well as a small amount (less than 1 gigawatt) of fuel cell capacity. Oil-fired steam plants, which have higher fuel costs and lower efficiencies, are not expected to account for any new capacity in the forecast.

Rising Natural Gas Prices, Falling Coal Prices Are Projected

Figure 65. Fuel prices to electricity generators, 1990-2025 (2001 dollars per million Btu)

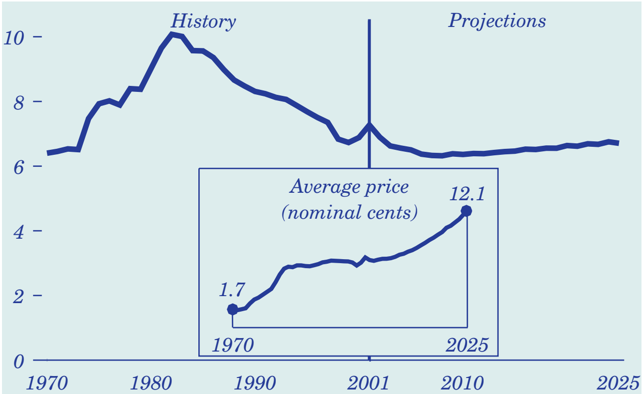


Electricity production costs are a function of the costs for fuel, operations and maintenance, and capital. Fuel costs make up most of the operating costs for fossil-fired units. Falling coal prices have reduced the fuel share of operating costs for coal-fired plants, to about 76 percent in 2000, whereas volatile prices and rapidly increasing usage rates have raised the fuel share for natural-gas-fired combined-cycle plants to 88 percent in 2000. For nuclear units, fuel costs are typically a much smaller portion of total production costs. Nonfuel operations and maintenance costs are a larger component of the operating costs for nuclear power units than for plants that use fossil fuels.

The impact of volatile natural gas prices in the forecast is more than offset by a combination of falling coal prices and stable nuclear fuel costs. After the price spikes of 2000 and 2001, natural gas prices to electricity suppliers are projected to rise by 1.8 percent per year in the forecast, from $3.07 per million Btu in 2002 to $4.60 in 2025 (Figure 65). The increases after 2002 are offset by forecasts of declining coal prices, declining capital expenditures, and improved efficiencies for new plants. Sufficient supplies of uranium and fuel processing services are expected to keep nuclear fuel costs around $0.40 per million Btu (roughly 4 mills per kilowatthour) through 2025. Oil prices to utilities are expected to increase by 0.7 percent per year after 2002, leading to a 51-percent decline in oil-fired generation (excluding combined heat and power) between 2001 and 2025. Oil currently accounts for 3 percent of total generation, and that share is expected to decline to 1 percent by 2025 as oil-fired steam generators are replaced by gas turbine technologies.

Average Electricity Prices Decline From 2001 Highs, Then Gradually Rise

Figure 66. Average U.S. retail electricity prices, 1970-2025 (2001 cents per kilowatthour)



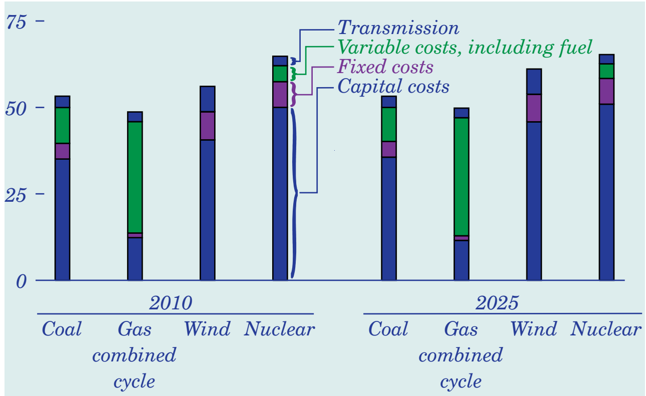
The average price of electricity in real 2001 dollars is expected to decline by an average of 1.6 percent per year from 2001 to 2008 (Figure 66) and then increase by 0.3 percent per year from 2008 to 2025 as natural gas prices rise. Electricity distribution prices are expected to decline as the cost of the distribution infrastructure is spread out over a growing amount of total electricity sales. Delivered electricity prices for residential, commercial, and industrial customers in 2025 are projected to be 7, 8, and 3 percent lower, respectively, than in 2001.

In 2002, 17 States and the District of Columbia had operating competitive retail electricity markets; Texas and Virginia opened their markets to competition in 2002; and Oregon restarted its restructuring process in November 2002. Five States with restructuring legislation on the books (Montana, Nevada, New Mexico, Oklahoma, and Arkansas) have delayed opening competitive retail markets. In addition, California's competitive retail market was suspended throughout 2002.

Specific restructuring plans differ from State to State and utility to utility, but most call for a transition period during which customer access will be phased in. The transition period reflects the time needed for the establishment of competitive market institutions and the recovery of stranded costs as permitted by regulators. It is assumed that competition will be phased in over 10 years, starting from the inception of restructuring in each region. In all the competitively priced regions, the generation price is set by the marginal cost of generation. Transmission and distribution prices are assumed to remain regulated.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 67. Projected levelized electricity generation costs, 2010 and 2025 (2001 mills per kilowatthour)



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 67) [*42*]. The reference case assumes a capital recovery period of 18 years. In addition, the cost of capital is based on competitive market rates, to account for the competitive risk of siting new units.

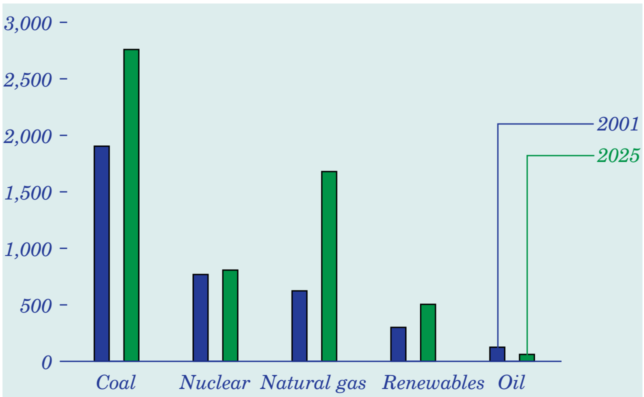
The costs and performance characteristics for new plants are expected to improve over time (Table 8), at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a slower rate as more units are built. The performance (efficiency) of new plants is also assumed to improve, with heat rates for advanced combined cycle and coal gasification units declining to 6,350 and 7,200 Btu per kilowatthour, respectively, by 2010. No further improvement is assumed after 2010.

Table 8. Costs of producing electricity from new plants, 2010 and 2025

Costs	2010 Advanced coal	2010 Advanced combined cycle	2025 Advanced coal	2025 Advanced combined cycle
	2001 mills per kilowatthour			
Capital	35.08	12.33	35.62	11.55
Fixed	4.53	1.34	4.53	1.34
Variable	10.37	32.21	9.85	34.14
Transmission	3.28	2.82	3.23	2.77
Total	**53.26**	**48.70**	**53.23**	**49.80**

Capacity Additions Are Expected at Existing Nuclear Power Plants

Figure 68. Projected electricity generation by fuel, 2001 and 2025 (billion kilowatthours)



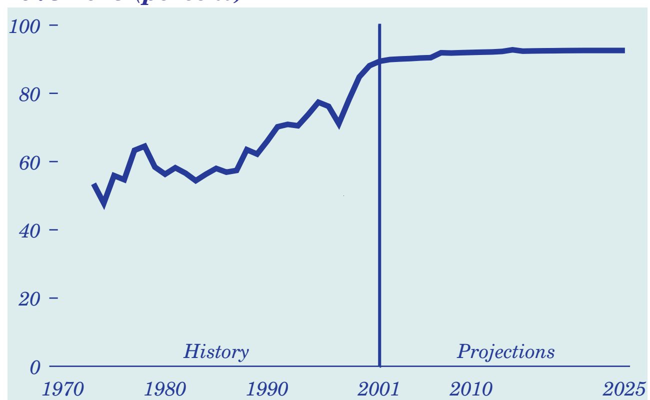
As they have since early in this century, coal-fired power plants are expected to remain the key source of electricity through 2025 (Figure 68). In 2001, coal accounted for 1,904 billion kilowatthours or 51 percent of total generation, including output at combined heat and power plants. Although coal-fired generation is projected to increase to 2,760 billion kilowatthours in 2025, increasing gas-fired generation is expected to reduce coal's share to 47 percent. Concerns about the environmental impacts of coal plants, their relatively long construction lead times, and the availability of economical natural gas make it unlikely that many new coal plants will be built in the near term. Nevertheless, the huge investment in existing coal plants and high utilization rates at those plants are expected to keep coal in its dominant position. By 2025, it is projected that 23 gigawatts of coal-fired capacity will be retrofitted with scrubbers to comply with environmental regulations.

As a result of improvements in performance and ongoing expansions of existing capacity, nuclear generation is expected to increase modestly through 2014 before leveling off. Between 2001 and 2016, about 4 gigawatts of total generating capacity is expected to be added through expansions at 88 of the Nation's 104 operable nuclear power units.

In percentage terms, natural-gas-fired generation is projected to show the largest increase, from 17 percent of the total in 2001 to 29 percent in 2025. As a result, by 2006, natural gas is expected to overtake nuclear power as the Nation's second-largest source of electricity. Generation from oil-fired plants is projected to remain fairly small throughout the forecast.

Nuclear Power Plant Capacity Factors Are Expected To Increase Modestly

Figure 69. Nuclear power plant capacity factors, 1973-2025 (percent)



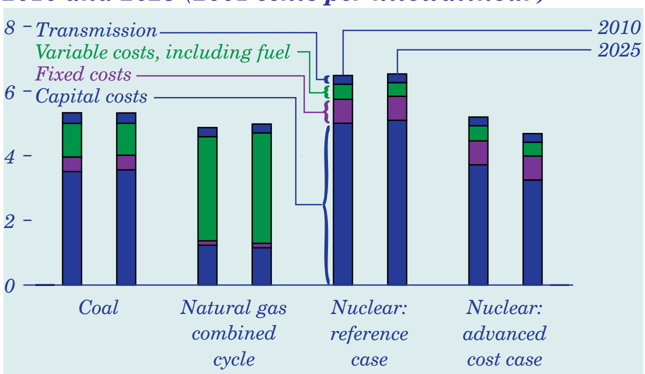
The United States currently has 104 operable nuclear units, which provided 20 percent of total electricity generation in 2001. The performance of U.S. nuclear units has improved in recent years, to a national average capacity factor of 89 percent in 2001 (Figure 69). It is assumed that performance improvements will continue, to an expected average capacity factor of 92 percent by 2010.

In the reference case, 3 percent of current nuclear capacity is projected to be taken out of service by 2025, but the retirements are more than offset by assumed increases in capacity at existing units. The U.S. Nuclear Regulatory Commission (NRC) approved 22 applications for power uprates in 2001, and another 22 were approved or pending in 2002. The reference case assumes that all the uprates will be made, as well as others expected by the NRC over the next 10 years, leading to an increase of 4.2 gigawatts in total nuclear capacity by 2025. No new nuclear units are expected to become operable between 2001 and 2025, because natural gas and coal-fired units are projected to be more economical.

Nuclear units are projected to be retired when their operation is no longer economical relative to the cost of building replacement capacity. By 2025, the majority of nuclear units will be beyond their original licensed lifetimes. As of October 2002, license renewals for 10 nuclear units had been approved by the NRC, and 16 other applications were being reviewed. As many as 23 additional applicants have announced intentions to pursue license renewals over the next 5 years, indicating a strong interest in maintaining the existing stock of nuclear plants.

Sensitivity Case Looks at Possible Reductions in Nuclear Power Costs

Figure 70. Projected levelized electricity costs by fuel type in the advanced nuclear cost case, 2010 and 2025 (2001 cents per kilowatthour)

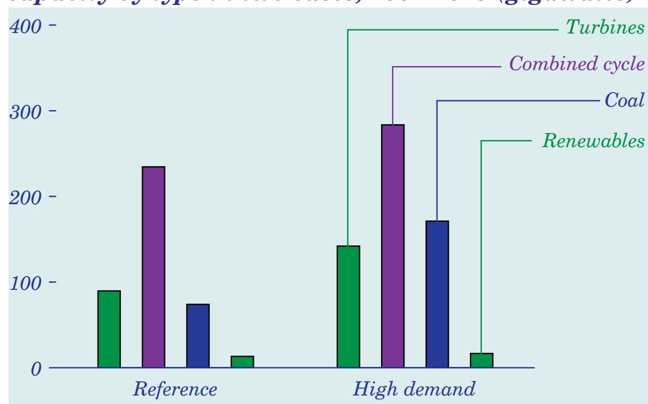


The *AEO2003* reference case assumptions for the cost and performance characteristics of new technologies are based on cost estimates by government and industry analysts, allowing for uncertainties about new, unproven designs. For nuclear power plants, an advanced nuclear cost case analyzes the sensitivity of the projections to lower costs for new plants. The more optimistic cost assumptions for the advanced cost case are consistent with goals endorsed by DOE's Office of Nuclear Energy, including progressively lower overnight construction costs—by 28 percent initially compared with the reference case and by 36 percent in 2025. Achieving those goals may require government support, including cost sharing for the first few units constructed. Cost and performance characteristics for all other technologies are assumed to be the same as those in the reference case.

Projected nuclear generating costs in the advanced nuclear cost case are competitive with the generating costs for new coal- and natural-gas-fired units toward the end of the projection period (Figure 70). A total of 2 gigawatts of new nuclear capacity is projected to come on line by 2020 in the advanced nuclear cost case, and 14 gigawatts by 2025; however, when the advanced nuclear cost assumptions are combined with improved costs and efficiencies for fossil and renewable fuel technologies, along with improvements in end-use technologies, no increase in total nuclear capacity is projected. The projections in Figure 70 are average generating costs, assuming generation at the maximum capacity factor for each technology; the costs and relative competitiveness of the technologies could vary across regions.

High Demand Assumption Leads to Higher Fuel Prices for Generators

Figure 71. Projected cumulative new generating capacity by type in two cases, 2001-2025 (gigawatts)

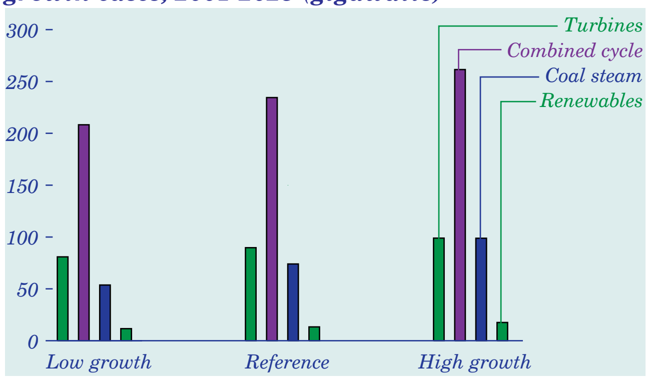


Electricity consumption grows in the forecast, but the projected rate of increase is less than historical levels as a result of assumptions about improvements in end-use efficiency, demand-side management programs, and population and economic growth. Different assumptions result in substantial changes in the projections. In a high demand case, electricity demand is assumed to grow by 2.5 percent per year between 2001 and 2025, as compared with annual growth of 2.2 percent per year between 1990 and 1999. In the reference case, electricity demand is projected to grow by 1.8 percent per year.

In the high demand case, 210 gigawatts more generating capacity is projected to be built between 2001 and 2025 than in the reference case (Figure 71). The shares of coal- and natural-gas-fired capacity additions (including combustion turbine, combined cycle, distributed generation, and fuel cell) are projected to be 27 percent and 70 percent, respectively, in the high demand case, compared with 17 and 80 percent, respectively, in the reference case. Coal consumption for electricity generation is projected to be 20 percent higher in the high demand case than in the reference case in 2025, natural gas consumption 13 percent higher, and carbon dioxide emissions 19 percent (163 million metric tons carbon equivalent) higher. More rapid assumed growth in electricity demand also leads to higher projected prices for electricity in 2025, averaging 7.0 cents per kilowatthour in the high demand case, compared with 6.7 cents in the reference case. Higher projected fuel prices, especially for natural gas, are the primary reason for the difference in electricity prices.

Rapid Economic Growth Would Boost New Natural Gas and Coal Capacity

Figure 72. Projected cumulative new generating capacity by technology type in three economic growth cases, 2001-2025 (gigawatts)



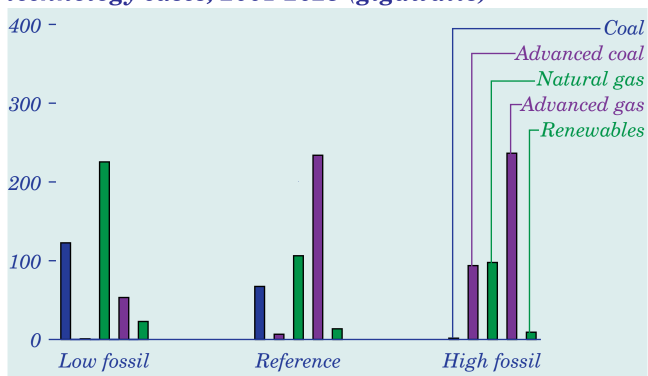
The projected annual average growth rate for GDP from 2001 to 2025 ranges from 3.5 percent in the high economic growth case to 2.5 percent in the low economic growth case. The difference leads to a 13-percent change in projected electricity demand in 2025, with a corresponding difference of 128 gigawatts in the amount of new capacity projected to be built in the high and low economic growth cases. In the high economic growth case, generators are expected to retire about 11 percent of their current capacity by 2025 as the result of increased operating costs for aging units.

More than half of the new capacity projected to be needed in the high economic growth case beyond that added in the reference case is expected to consist of new natural-gas-fired plants, which make up 56 percent of the projected additional new capacity. The stronger assumed growth also is projected to stimulate additions of coal-fired plants, accounting for 36 percent of the increase in projected capacity additions in the high economic growth case over those projected in the reference case (Figure 72).

Current construction costs for a typical plant range from $536 per kilowatt for combined-cycle technologies to $1,367 per kilowatt for coal-steam technologies. Those costs, along with the difficulty of obtaining permits and developing new generating sites, make refurbishment of existing power plants a profitable option. Between 2001 and 2025, generators are expected to maintain most of their older coal-fired plants while retiring many older, higher cost oil- and natural-gas-fired steam generating plants.

Gas-Fired Technologies Lead New Additions of Generating Capacity

Figure 73. Projected cumulative new generating capacity by technology type in three fossil fuel technology cases, 2001-2025 (gigawatts)

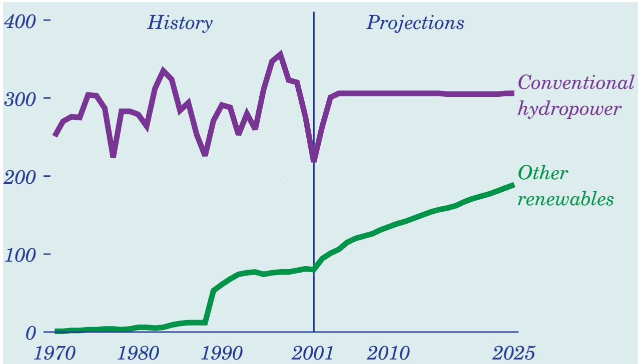


The *AEO2003* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Numerical values for the characteristics of different technologies are determined in consultation with industry and government specialists. In the high fossil fuel case, capital costs and/or heat rates for advanced fossil-fired generating technologies (integrated coal gasification combined cycle, advanced combined cycle, and advanced combustion turbine) reflect potential improvements in costs and efficiencies as a result of accelerated research and development. The low fossil fuel case assumes that capital costs and heat rates for advanced technologies will remain flat throughout the forecast at 2002 levels.

The projected share of additions accounted for by natural gas technologies varies from 66 percent to 80 percent across the cases, and the projected mix between current and advanced gas technologies varies significantly (Figure 73). In the low fossil fuel case 19 percent (53 gigawatts) of the gas plants projected to be added are advanced technology facilities, as compared with 71 percent (236 gigawatts) in the high fossil fuel case. Coal-fired capacity makes up a higher share of projected additions in both the low and high fossil fuel cases (29 percent and 22 percent, respectively) than in the reference case (17 percent). In the low case, conventional coal-fired generating capacity is more competitive with new natural-gas-fired capacity because no improvement is assumed for advanced natural gas technologies. In the high case, advanced coal technologies are more competitive as a result of the assumed rapid pace of technology improvements.

Increases in Nonhydropower Renewable Generation Are Expected

Figure 74. Grid-connected electricity generation from renewable energy sources, 1970-2025 (billion kilowatthours)

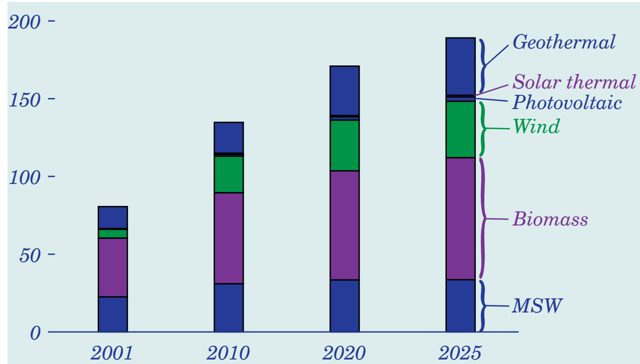


In the *AEO2003* reference case, despite improvements and incentives, grid-connected generators that use renewable fuels (including combined heat and power and other end-use generators) are projected to remain minor contributors to U.S. electricity supply, increasing from 298 billion kilowatthours of generation in 2001 (8.0 percent of total generation and 8.7 percent of retail sales) to 495 billion kilowatthours in 2025 (8.5 percent of generation and 9.4 percent of sales). Extremely low precipitation in 2001 reduced hydroelectric generation to 218 billion kilowatthours. Despite the net addition of 560 megawatts of new capacity by 2025, environmental and other requirements are projected to limit conventional hydroelectric generation to 306 billion kilowatthours in 2025—5.3 percent of generation and 5.8 percent of sales (Figure 74).

Nonhydroelectric renewables account for 4 percent of projected additions to generating capacity from 2001 to 2025. Generation from nonhydropower renewable energy sources is projected to increase from 80 billion kilowatthours in 2001 (2.1 percent of generation and 2.3 percent of sales) to 189 billion in 2025 (3.3 percent of generation and 3.6 percent of sales). The largest source of nonhydroelectric renewable generation in the forecast is biomass, including combined heat and power and co-firing in coal-fired power plants. Electricity generation from biomass is projected to increase from 38 billion kilowatthours in 2001 to 78 billion kilowatthours (1.3 percent of generation and 1.5 percent of sales) in 2025. Most of the increase (62 percent) is expected to come from combined heat and power and a smaller amount from co-firing with coal.

Biomass, Wind, and Geothermal Lead Growth in Renewables

Figure 75. Projected nonhydroelectric renewable electricity generation by energy source, 2010, 2020, and 2025 (billion kilowatthours)



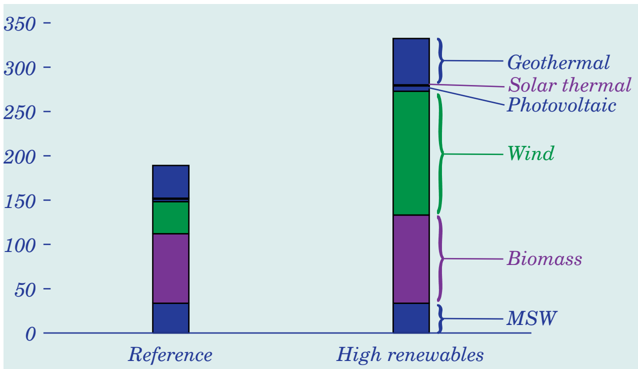
In addition to biomass, significant increases are projected for both geothermal energy and wind power capacity from 2001 to 2025 (Figure 75). Geothermal capacity, all located in western States, is projected to increase to 5.6 gigawatts, supplying 37 billion kilowatthours of electricity (0.6 percent of total generation) in 2025. Wind capacity increases by nearly 300 percent, to 12.0 gigawatts in 2025, much of it in response to State mandates. Generation from wind plants is projected to increase more rapidly than capacity, from less than 6 billion kilowatthours in 2001 to more than 36 billion in 2025, reflecting both a full year's output from capacity that entered service in mid-2001 and expected improvement in the productivity of future wind turbines. Despite expected significant near-term growth, mid-term prospects for wind power expansion are uncertain, depending on future cost and performance, transmission availability, extension of the Federal production tax credit and other incentives, energy security and public interest, and environmental preferences.

Electricity generation from municipal solid waste, including waste combustion and landfill gas, is projected to increase by 12 billion kilowatthours from 2001 to 2025, to nearly 34 billion kilowatthours. No new waste-burning capacity is expected, but landfill gas capacity is projected to increase by 1.1 gigawatts.

Solar technologies overall are not expected to make significant contributions to U.S. grid-connected electricity supplies through 2025. In total, grid-connected photovoltaic and solar thermal generators are projected to supply about 4 billion kilowatthours (0.07 percent of total generation) in 2025 [*43*].

Wind Energy Could Gain Most From Cost Reductions and Tax Credits

Figure 76. Projected nonhydroelectric renewable electricity generation by energy source in two cases, 2025 (billion kilowatthours)

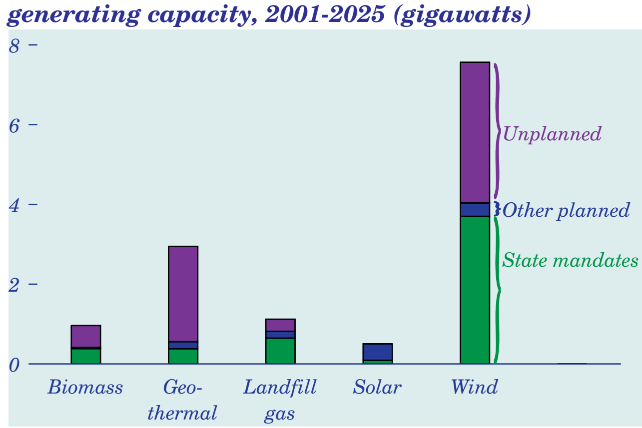


The high renewables case assumes more favorable characteristics for nonhydroelectric renewable energy technologies than in the reference case, including lower capital costs, higher capacity factors, and lower operating costs for some technologies [*44*]. The assumptions in the high renewables case approximate the renewable energy goals of the U.S. Department of Energy [*45*]. Fossil and nuclear technology assumptions are not changed from the reference case.

More rapid technology improvements are projected to increase renewable energy use in the high renewables case, but the predominant role of fossil-fueled technologies in U.S. electricity supply does not change. Total generation from nonhydroelectric renewables is projected to reach 332 billion kilowatthours in 2025, compared with about 189 billion kilowatthours in the reference case (Figure 76), increasing from about 3 percent to almost 6 percent of total generation. About 103 billion kilowatthours of the projected increase is generated from wind power, 15 billion kilowatthours from baseload geothermal, and 21 billion kilowatthours from net increases in biomass use, with increases for dedicated biomass plants and industrial combined heat and power applications more than offsetting reductions in biomass co-firing. Central-station solar technologies remain too expensive for use in new capacity additions, but the use of distributed photovoltaics in end-use markets is expected to more than double from the reference case. The projected increase in renewable energy use in the high renewables case reduces fossil fuel use relative to the reference case projection, lowering total projected carbon dioxide emissions by 31 million metric tons carbon equivalent (1.4 percent).

State Mandates Call for More Generation From Renewable Energy

Figure 77. Projected additions of renewable generating capacity, 2001-2025 (gigawatts)



AEO2003 projects additions of 19 gigawatts of new renewable generating capacity through 2025, including 14 gigawatts in the electric power sector, 4 gigawatts in end-use combined heat and power, and 0.9 gigawatts in small-scale end-use applications. In the electric power sector, 5.2 gigawatts is projected as a result of State mandates (wind power 3.7 gigawatts, landfill gas 0.6 gigawatts, geothermal 0.4 gigawatts, solar thermal 0.09 gigawatts, solar photovoltaics 3 megawatts) and the rest from commercial projects (Figure 77). Projected commercial projects include 0.08 gigawatts of central-station solar thermal and 0.3 gigawatts of grid-connected central-station photovoltaic capacity that is assumed to be built for testing, demonstration, environmental, and other reasons.

In the reference case, a number of States with mandates and renewable portfolio standards in place are projected to add significant amounts of renewable capacity after 2001, including Massachusetts (1,112 megawatts), Texas (1,001 megawatts), Nevada (778 megawatts), California (623 megawatts), Minnesota (399 megawatts), New Jersey (340 megawatts), and New York (335 megawatts). Other States with smaller mandate requirements include Arizona, Hawaii, Iowa, Illinois, Montana, Oregon, West Virginia, and Wisconsin. Most of the new capacity is expected to be constructed in the near term—47 percent by 2003 and more than 60 percent by 2005. Because the current Federal production tax credit for new wind capacity is scheduled to expire after December 2003, 2,475 megawatts (58 percent) of identified new wind capacity is projected to be built before the end of 2003.