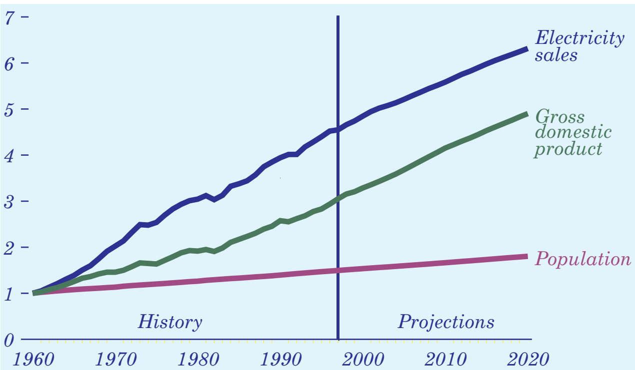
Electricity Sales Growth Is Expected To Accompany GDP Growth

Figure 66. Population, gross domestic product, and electricity sales growth, 1960-2020 (index, 1960 = 1)



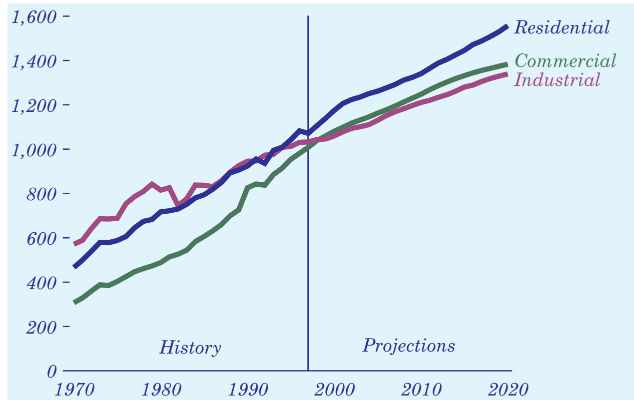
While generators and cogenerators try to adjust to the evolving structure of the electricity market, they are also faced with slower growth in demand than in the past. Historically, the demand for electricity has been related to economic growth. This positive relationship will continue, but the magnitude of the ratio is uncertain.

During the 1960s, electricity demand grew by more than 7 percent a year, nearly twice the rate of economic growth (Figure 66). 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. The same trend is expected to continue throughout the forecast, as retiring equipment is replaced with new, more efficient units.

Changing consumer markets could mitigate the slowing of electricity demand growth seen in these projections. New electric appliances are introduced frequently. Only a few years ago, no one foresaw the growth in home computers, facsimile machines, copiers, and security systems, all powered by electricity. If new uses of electricity are more substantial than currently expected, they could partially offset future efficiency gains.

Residential Consumption Leads Projected Electricity Sales Growth

Figure 67. Annual electricity sales by sector, 1970-2020 (billion kilowatthours)



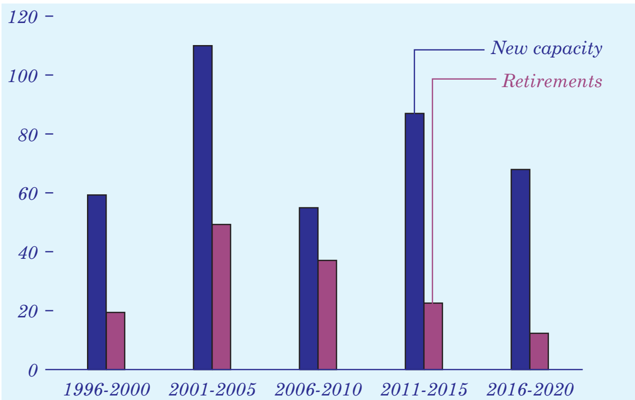
With the number of U.S. households projected to rise by 1.1 percent a year between 1997 and 2020, residential demand for electricity grows by 1.6 percent annually (Figure 67). Residential electricity demand changes as a function of the time of day, week, or year. During summer, residential demand peaks 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 satisfy peak demand. Although many regions currently have surplus baseload capacity, strong growth in the residential sector will result in a need for more “peaking” capacity. Between 1997 and 2020, generating capacity from gas turbines and internal combustion engines is expected to more than triple.

Electricity demand in the commercial and industrial sectors grows by 1.4 and 1.1 percent a year, respectively, between 1997 and 2020. Annual commercial floorspace growth of 0.8 percent and industrial output growth of 1.9 percent drive the increase.

In addition to sectoral sales, cogenerators in 1997 produced 146 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. By 2020, these producers are expected to see only a slight decline in their share of total generation, increasing their own-use generation to 184 billion kilowatthours as demand for manufactured products increases.

Rising Demand, Plant Retirements Create a Need for New Generators

Figure 68. New generating capacity and retirements, 1996-2020 (gigawatts)



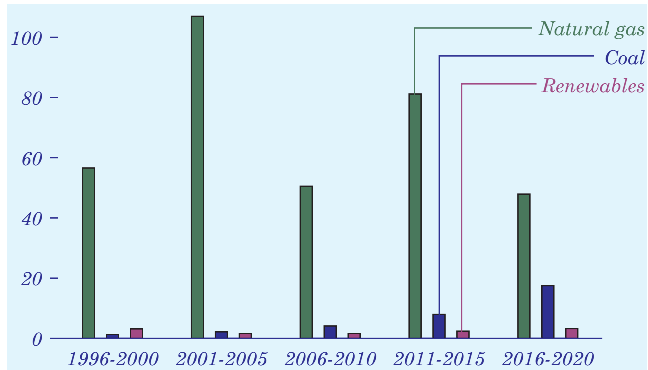
Despite slower demand growth, 363 gigawatts of new generating capacity will be needed by 2020 to meet growing demand and to replace retiring units. Between 1997 and 2020, 50 gigawatts (51 percent) of current nuclear capacity and 76 gigawatts (16 percent) of current fossil-steam capacity [*61*] are expected to be retired. Of the 155 gigawatts of new capacity needed after 2010 (Figure 68), 16 percent will replace retired nuclear capacity.

The reduction in baseload nuclear capacity has a marked impact on the electricity outlook after 2010: 44 percent of the new combined-cycle and 78 percent of the new coal capacity projected in the entire forecast are brought on line between 2010 and 2020. Before the advent of natural gas combined-cycle plants, fossil-fired baseload capacity additions were limited primarily to pulverized-coal steam units; however, efficiencies for combined-cycle units are expected to approach 54 percent by 2010, compared to 38 percent for coal-steam units, with construction costs only about 37 percent those for coal-steam plants.

As older nuclear power plants age and their operating costs rise, more than one-half of currently operating nuclear capacity is expected to retire by 2020. More optimistic assumptions about operating lives and costs for nuclear units would reduce the need for new fossil-based capacity and reduce fossil fuel prices.

More Than a Thousand New Plants Could Be Needed by 2020

Figure 69. Electricity generation and cogeneration capacity additions by fuel type, 1996-2020 (gigawatts)

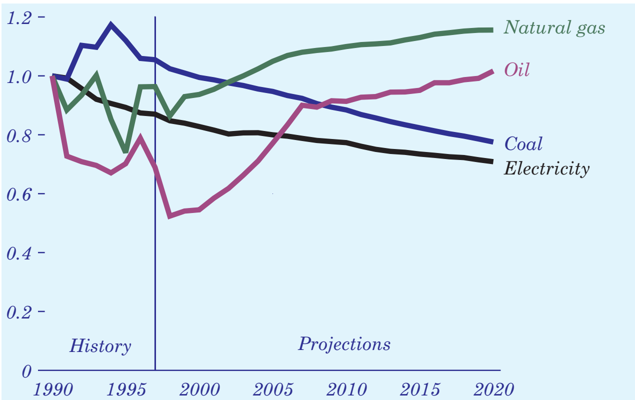


Before building new capacity, utilities are expected to use other options to meet demand growth—maintenance of existing plants, power imports from Canada and Mexico, and purchases from cogenerators. Even so, assuming an average plant capacity of 300 megawatts, a projected 1,210 new plants with a total of 363 gigawatts of capacity will be needed by 2020 to meet growing demand and to offset retirements. Of the new capacity, 88 percent is projected to be combined-cycle or combustion turbine technology fueled by natural gas or both oil and gas (Figure 69). Both technologies are designed primarily to supply peak and intermediate capacity, but combined-cycle technology can also be used to meet baseload requirements.

More than 32 gigawatts of new coal-fired capacity is projected to come on line between 1996 and 2020, accounting for almost 9 percent of all capacity expansion. Competition with low-cost gas-turbine-based technologies and the development of more efficient coal gasification systems has compelled vendors to standardize designs for coal-fired plants in efforts to reduce capital and operating costs in order to maintain a share of the market. Renewable technologies account for the remaining 3 percent of capacity expansion by 2020—primarily, wind and biomass gasification units. Oil-fired steam plants, with higher fuel costs and lower efficiencies, account for very little of the new capacity in the forecast.

Projected Declines in Coal Prices Would Mean Cheaper Electricity

Figure 70. Fuel prices to electricity suppliers and electricity price, 1990-2020 (index, 1990 = 1)



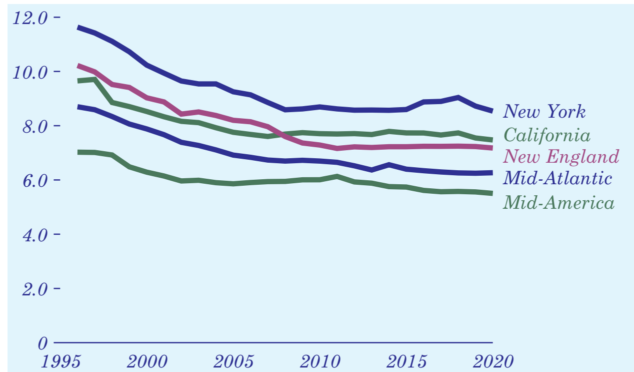
Between 1997 and 2020, the average price of electricity in real 1997 dollars is projected to decline by 0.9 percent a year as a result of competition among electricity suppliers (Figure 70). By sector, projected prices in 2020 are 16, 21, and 22 percent lower than 1997 prices for residential, commercial, and industrial customers.

The cost of producing electricity is a function of fuel costs, operating and maintenance costs, and the cost of capital. For existing plants, fuel costs typically represent $24 million annually or 79 percent of the total operational costs (fuel and operating and maintenance) for a 300-megawatt coal-fired plant and $31 million annually or 93 percent of the total operational costs for a gas-fired combined-cycle plant of the same size in 1997.

Natural gas prices to electricity suppliers rise by 0.8 percent a year in the forecast, from $2.76 per thousand cubic feet in 1997 to $3.31 in 2020. Gas-fired electricity generation increases by 211 percent, from 509 to 1,582 billion kilowatthours. Offsetting these increases are declining coal prices, declining capital expenditures, and improved efficiencies for new plants. Oil prices to utilities are expected to increase by 1.7 percent a year. As a result, oil-fired generation is expected to decline by more than 66 percent between 1997 and 2020. However, oil currently accounts for only 2.6 percent of total generation, and that share is expected to decline to 0.6 percent by 2020 as oil-fired steam generators are replaced by gas turbine technologies.

Retail Competition Is Expected To Lower Electricity Prices

Figure 71. Electricity prices in five regions in transition to competitive markets, 1997-2020 (1997 cents per kilowatthour)



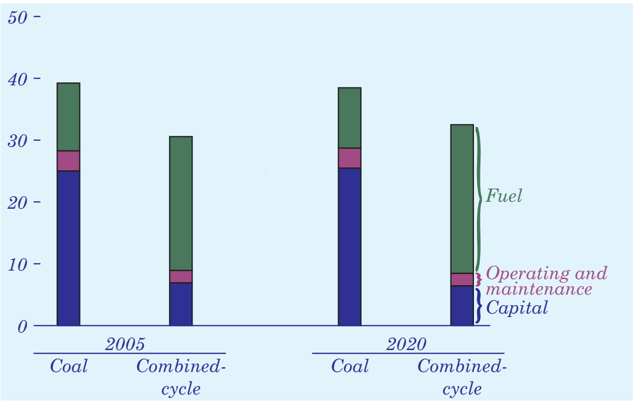
The reference case assumes a transition to competitive pricing in five regions—California, New York, New England, the Mid-Atlantic Area Council (consisting of Pennsylvania, Delaware, New Jersey and Maryland), and the Mid-America Interconnected Network (consisting of Illinois and parts of Wisconsin and Missouri). The 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. The region-wide 10-percent rate reduction required in California is represented. For the other regions it is assumed that competition will be phased in between 1999 and 2007, with fully competitive prices beginning in 2008. In all the competitively priced regions, the generation price (the price for the energy alone) is set by the marginal cost of generation. Transmission and distribution prices are assumed to remain regulated.

Prices in these regions fall rapidly in the early years of the projections, especially in the regions that have the highest prices today (Figure 71). From 1997 through 2005 the average price in the five regions declines by 2.6 percent a year. In addition, by 2020 the range of prices across the regions is expected to be much narrower than it is today. In 1997, the difference in electricity prices among the regions was 6.7 cents per kilowatthour, but by 2020 it is expected to narrow to 3.9 cents per kilowatthour.

New Gas-Fired Generators Could Be Less Expensive Than Coal Plants

Figure 72. Electricity generation costs, 2005 and 2020 (1997 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 levelized costs (Figure 72). The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is increased by 1 percentage point, to account for the competitive risk of siting new units.

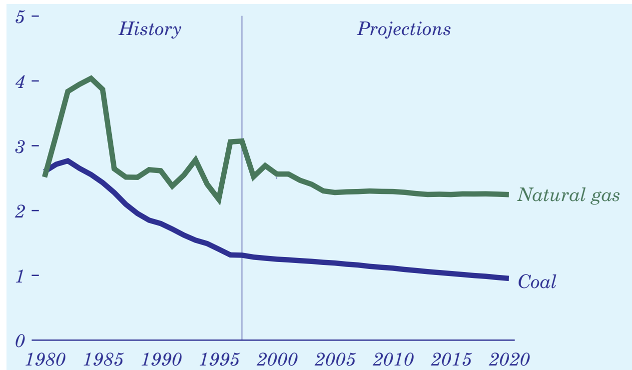
In the *AEO99* forecasts, the costs and performance characteristics for new plants improve over time, at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to refelct the optimism inherent in early project cost estimates. As project developers gain experience, the costs are assumed to decline rapidly. 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 declining by 5 to 18 percent between 1995 and 2020, depending on the technology (Table 5).

Table 5. Costs of producing electricity from new plants, 2005 and 2020

Item	2005 Conventional pulverized coal	2005 Advanced combined cycle	2020 Conventional pulverized coal	2020 Advanced combined cycle
	1997 mills per kilowatthour			
Capital	25.02	6.92	25.47	6.45
O&M	3.25	2.01	3.25	2.01
Fuel	10.96	21.64	9.75	24.03
Total	**39.22**	**30.56**	**38.42**	**32.49**
	Btu per kilowatthour			
Heat rate	9,253	6,639	9,087	6,350

Lower Generating Costs Are Projected for Both Coal and Gas Plants

Figure 73. Average fuel costs for coal- and gas-fired generating plants, 1980-2020 (1997 cents per kilowatthour)

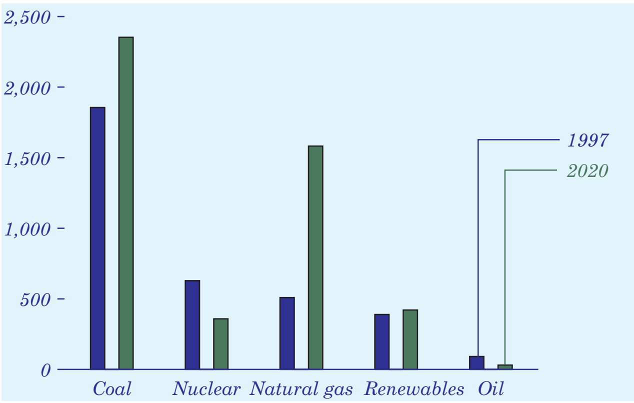


Since 1980, the per-kilowatthour fuel costs for gas-fired and, particularly, coal-fired power plants have fallen significantly (Figure 73). For coal plants, fuel prices have been declining since the early 1980s. For gas plants, fuel prices rose in the early 1980s but declined sharply in 1986. Generating costs for coal-fired plants decreased by 49 percent from 1980 to 1996, and the costs for gas-fired plants, even with the price increase that occurred in 1996, were still 24 percent lower than their peak in 1984.

The trend of declining costs for coal-fired plants is expected to continue as coal prices continue falling. In addition, nonfuel operations and maintenance costs are also expected to fall. In 1982, coal-fired steam plants used 250 employees per gigawatt of installed capacity, but utilities were able to reduce that number to 200 by 1995. Efforts to cut staff and reduce operating costs were prompted by the combination of technology improvements and competitive pressure. The amount by which utilities can continue to cut costs is uncertain, but many analysts agree that further reductions are possible. For gas-fired plants, per-kilowatthour generating costs are expected to fall early in the projections before leveling off. Although natural gas prices are expected to increase, the fuel costs per kilowatthour for gas-fired power plants are projected to remain steady as the efficiencies of new plants improve, offsetting the rise in fuel prices.

Coal-Fired Plants Are Projected To Dominate Electricity Generation

Figure 74. Electricity generation by fuel, 1997 and 2020 (billion kilowatthours)



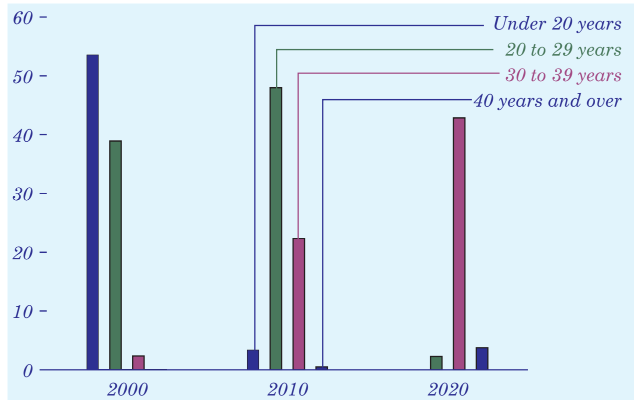
As they have since early in this century, coal-fired power plants are expected to remain the dominant source of electricity through 2020 (Figure 74). In 1997, coal accounted for 1,856 billion kilowatthours or 53 percent of total generation. Although coal-fired generation increases to 2,352 billion kilowatthours, increasing gas-fired generation reduces coal s share to 49 percent in 2020. oncerns 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 before 2000. evertheless, slow demand growth and the huge investment in existing plants will keep coal in its dominant position. y 2020, it is projected that 26 gigawatts of capacity will be retrofitted with scrubbers and 217 gigawatts with x control technologies, to meet the re uirements of the lean Air Act Amendments of 1990 (AAA90) and the zone Transport ule (see egislation and egulations, page 12).

The large investment in existing plants will also make nuclear power a growing source of electricity at least through 2000. ecause the recent performance of nuclear power plants has improved substantially, nuclear generation is projected to increase until 2000, then decline as older units are retired.

In percentage terms, gas-fired generation increases the most, from 14 percent of the 1997 total to 33 percent in 2020. As a result, by 2003, natural gas overtakes nuclear power as the ation s second-largest source of electricity. Generation from oil-fired plants remains fairly small throughout the forecast.

More Than Half of U.S. Nuclear Capacity Could Close by 2020

Figure 75. Operable nuclear power capacity by age of plant, 2000, 2010, and 2020 (gigawatts)

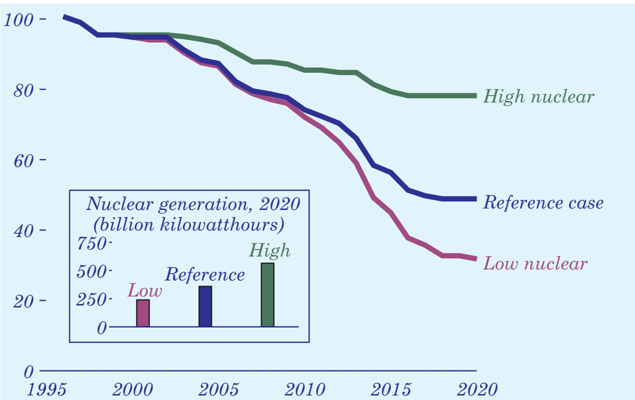


The nuclear power plants now in operation are aging, and many will reach the end of their operating licenses in the forecast period (Figure 75). In the reference case, 51 percent of current nuclear capacity is expected to be taken out of service by 2020. Some early retirements are included, based on the assumption that major capital investments will be needed after 30 years of operation and will be made only if they are more economical than building new capacity. In all, 27 nuclear units are projected to be retired early in the reference case. o new nuclear units are expected to become operable by 2020, because natural gas and coal-fired plants are projected to be more economical. y 2020, the nuclear share of total electricity generation is projected to fall to 7 percent from its current share of 18 percent.

Although some nuclear units are expected to be retired before the expiration of their 40-year operating licenses, others are expected to operate longer than their current license terms. The .S. uclear egulatory ommission has defined an application process for utilities to renew an existing license for 20 additional years. In 1998, two utilities altimore Gas and Electric and uke ower submitted license renewal applications. The forecast assumes that license renewal will be chosen if a further capital investment to extend the operating life of a nuclear unit after 40 years is more economical than building new capacity. The reference case projects that six units with license expiration dates before 2020 will continue operating after license renewals.

Favorable Conditions Could Forestall Some Nuclear Retirements

Figure 76. Operable nuclear capacity in three cases, 1996-2020 (gigawatts)

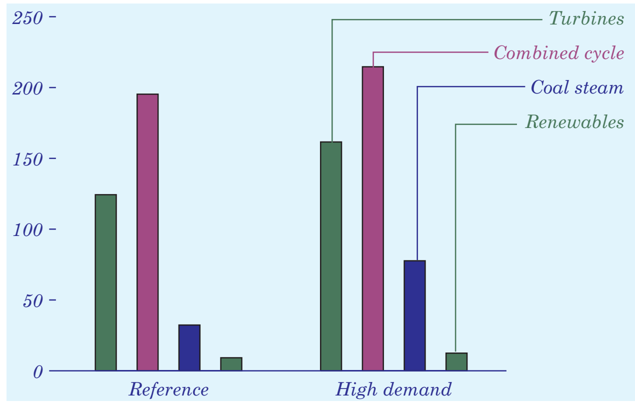


Two alternative cases—the high and low nuclear cases—show how nuclear plant retirement decisions affect the projections for capacity (Figure 76). The low nuclear case assumes that the capital expenditures required after 30 and 40 years of operation are higher than assumed in the reference case, leading to the retirement of 15 additional units by 2020. Higher costs could result from more severe degradation of the units or from waste disposal problems. The high nuclear case assumes that no additional capital expenditures will be required after 40 years and that more license renewals will be obtained by 2020. Conditions favoring license renewal could include performance improvements, a solution to the waste disposal problem, or stricter limits on emissions from fossil-fired generating facilities in response to environmental concerns.

In the low nuclear case, more than 60 new fossil-fired units (assuming an average size of 300 megawatts) would be built to replace additional retiring nuclear units. The new capacity would be split between coal-fired (30 percent), combined-cycle (28 percent), and combustion turbine (42 percent) units. The additional fossil-fueled capacity would produce 17 million metric tons of carbon emissions above those in the reference case in 2020. In the high nuclear case, 28 gigawatts of new fossil-fired capacity would not be needed, as compared with the reference case, and carbon emissions would be reduced by 11 million metric tons in 2010 and 31 million metric tons in 2020 (4 percent of total emissions by electricity generators).

Gas-Fired Capacity Additions Are Favored in the Projections

Figure 77. Cumulative new generating capacity by type in two cases, 1997-2020 (gigawatts)

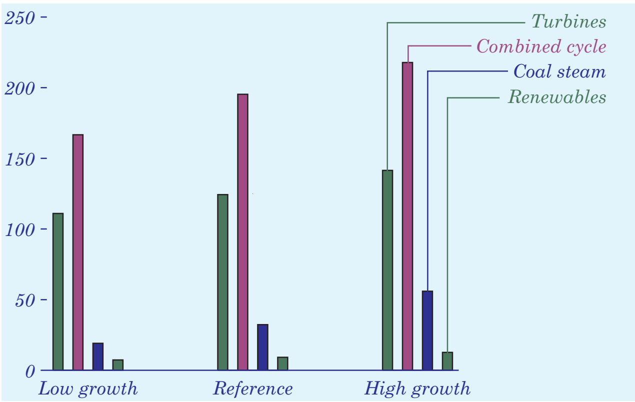


Electricity consumption grows in the forecast, but the rate of increase lags behind historical levels as a result of assumptions regarding efficiency improvements in end-use technologies, demand-side management programs, and population and economic growth. Deviations from these assumptions could result in substantial changes in electricity demand. For example, if electric vehicles enter the market faster than expected, the demand for electricity would also increase more rapidly. Lower electricity prices due to the effect of competitive markets could lead to increased consumption and less concern for conservation. In a high demand case, electricity demand is assumed to grow by 2.0 percent a year between 1997 and 2020, comparable to the annual growth rate of 2.2 percent between 1990 and 1997. In the reference case, electricity demand is projected to grow by 1.4 percent a year.

In the high demand case, 113 gigawatts more new generating capacity is built than in the reference case between 1997 and 2020—equivalent to 376 new 300-megawatt generating plants (Figure 77). The shares of coal- and gas-fired capacity additions are about the same—9 and 88 percent, respectively, in the reference case and 16 and 81 percent in the high demand case. Relative to the reference case, there is a 12-percent increase in coal consumption and a 17 percent increase in natural gas consumption in the high demand case, and carbon emissions from electricity generation are 96 million metric tons (13 percent) higher.

Stronger Economic Growth Would Require More Generating Capacity

Figure 78. Cumulative new generating capacity by type in three cases, 1997-2020 (gigawatts)



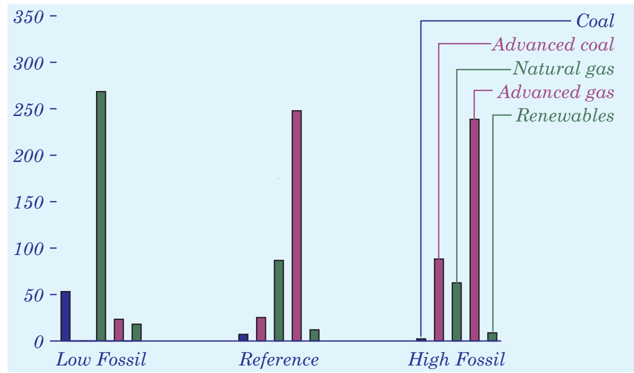
From 1997 to 2020, the annual average growth rate for GDP ranges between 2.6 and 1.5 percent in the high and low economic growth cases, respectively. The difference of a percentage point in the economic growth rate leads to a 17-percent change in electricity demand in 2020, with a corresponding difference of 124 gigawatts of new capacity required in the high and low economic growth cases. Utilities are expected to retire between 19 and 20 percent of their current generating capacity (equivalent to 460 to 505 300-megawatt generating plants) by 2020 as the result of increased operating costs for aging plants.

Most of the new capacity needed in the high economic growth case is expected to consist of natural-gas-fired plants—both turbine and combined-cycle units—which make up almost 60 percent of the projected new capacity in the high growth case. The stronger growth also stimulates additions of coal-fired plants, particularly in the later years, when higher natural gas prices make new coal-fired facilities more attractive economically (Figure 78).

Current construction costs for a typical 400-megawatt plant range from $400 per kilowatt for combined-cycle technologies to $1,079 per kilowatt for coal-steam technologies. These costs, combined with the difficulty of obtaining permits and developing new generating sites, make refurbishment of existing power plants a profitable option for utility resource planners. Between 1997 and 2020, utilities are expected to maintain most of their older coal-fired plants while retiring many of their older oil- and gas-fired generating plants.

Higher Costs for New Technologies Would Favor New Coal-Fired Capacity

Figure 79. Cumulative new electricity generating capacity by technology type in three cases, 1997-2020 (gigawatts)

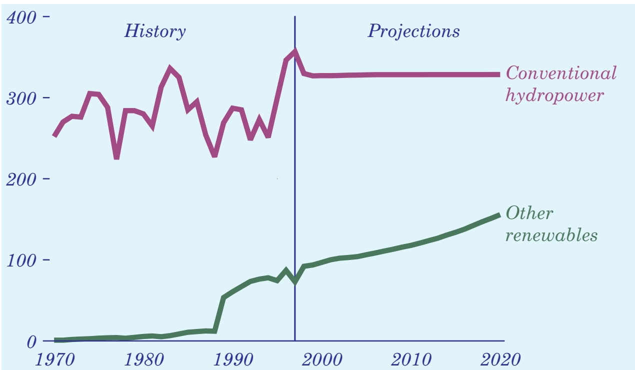


The *AEO99* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Numerical values for the characteristics of different technologies are determined in consultation with industry and government specialists. In the high fossil fuel case, capital costs, operating costs, and heat rates for advanced fossil-fired generating technologies (integrated coal gasification combined cycle, advanced combined cycle, advanced combustion turbine, and molten carbonate fuel cell) were revised to reflect potential improvements in costs and efficiencies as a result of accelerated research and development. The low fossil fuel case assumes that no advanced technologies will come on line during the projection period.

Because of their high initial capital costs, integrated coal gasification combined cycle (IGCC) units do not become competitive with gas technologies until late in the projections in the reference case. In the high fossil fuel case, which assumes lower initial capital costs and higher efficiencies for the IGCC technology, 88 gigawatts of IGCC capacity are projected. The low fossil fuel case, as compared with the reference case, projects 77 gigawatts less gas-fired capacity additions, 51 gigawatts more coal-fired capacity additions, and 6 gigawatts more renewable capacity additions between 1997 and 2020 (Figure 79).

Steady Growth Is Expected for Renewable Electricity Supply

Figure 80. Grid-connected electricity generation from renewable energy sources, 1970-2020 (billion kilowatthours)

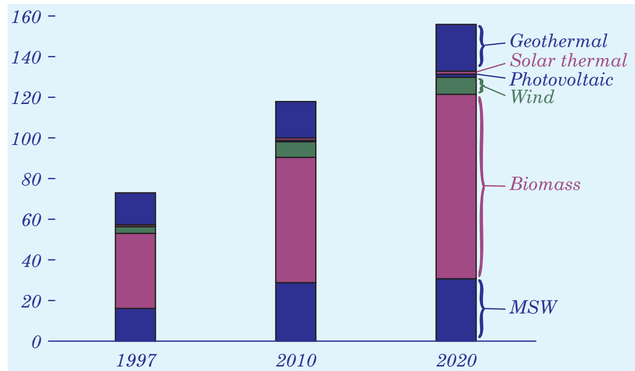


In the *AEO99* projections, expectations for renewables in the U.S. electricity supply are mixed. Targeted investment raises near-term projections, but in the long term renewables are at a disadvantage because of their higher costs, competition from fossil technologies, low fossil fuel prices, and the competitive marketplace. Total U.S. electricity generation from renewable resources increases from 430 billion kilowatthours in 1997 to 484 billion kilowatthours in 2020 (Figure 80). Most of the growth is attributed to biomass; geothermal, municipal solid waste, and wind generation also increase substantially. Overall, renewables are projected to make up a smaller share of U.S. electricity generation in 2020, declining from over 12 percent in 1997 to barely 10 percent in 2020.

Conventional hydroelectricity, which currently dominates U.S. renewable generation, is not expected to increase through 2020. Almost no new hydropower capacity is expected. As a result, after an excellent water year in 1997, hydroelectricity quickly slips from 357 billion kilowatthours (about 10 percent of U.S. electricity supply) to 329 billion kilowatthours a year (less than 7 percent) in 2020. Further, other water priorities—such as to enhance fish populations, for irrigation, or for recreation—could further reduce hydropower output.

Biomass Leads Projected Growth in Generation From Renewables

Figure 81. Nonhydroelectric renewable electricity generation by energy source, 1997, 2010, and 2020 (billion kilowatthours)

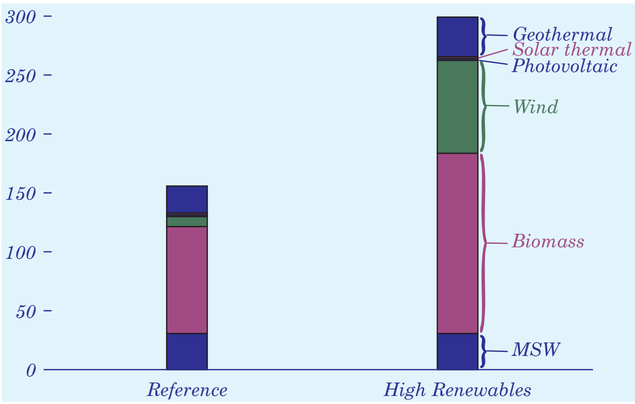


Renewables other than hydropower are projected to grow more substantially (Figure 81) as a result of near-term State and utility programs and the long-run demand for new capacity. Biomass use grows the most in the projections, to 91 billion kilowatthours in 2020, approaching 2 percent of U.S. generation. The increases reflect expected improvements in generating technologies, new energy crops, and growth of industries using wood byproducts for cogeneration. More efficient new units and retirements of less efficient older ones result in a 47-percent increase in geothermal generation through 2020. Generation from municipal solid waste grows to more than 30 billion kilowatthours, reflecting increased use of landfill gas and improved generating efficiency. Wind power also increases—extending from California to the Midwest, Texas, and the Northwest—helped in the near term by State and utility support programs. Overall, nonhydroelectric renewables increase from 2 percent of total generation in 1997 to more than 3 percent in 2020.

Solar thermal and photovoltaic technologies are not expected to become notable contributors to overall U.S. grid-connected electricity supply by 2020. Solar thermal technologies remain more costly than alternatives. Photovoltaics, while too costly for large-scale grid applications, are increasingly competitive for small, high-value niche markets, and the technology has attracted State and public interest as an environmentally attractive alternative. Off-grid applications and exports of photovoltaics are expected to continue robust growth.

Technology Improvements Could Increase Renewable Generation

Figure 82. Nonhydroelectric renewable electricity generation in two cases, 2020 (billion kilowatthours)

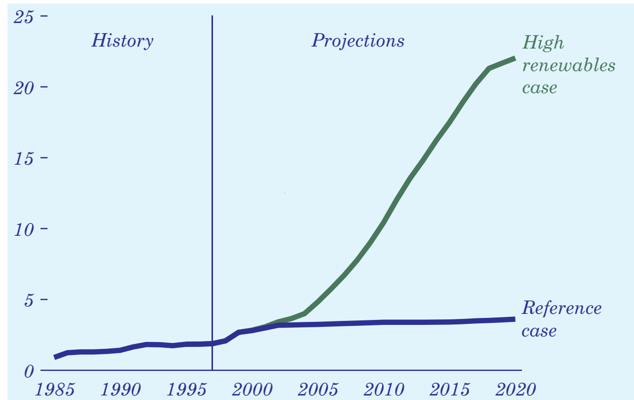


To examine more rapid improvements in renewable technologies, the high renewables case replaces the *AEO99* reference case assumptions for capital costs, operations and maintenance expenses, and capacity factors for nonhydroelectric renewables with more optimistic Department of Energy renewable energy assumptions, with no change in the assumptions for nuclear and fossil fuel technologies. The high renewables case also assumes that the yields for energy crops grown on pasture and crop land will be nearly 20 percent higher than expected in the reference case, and that the additional capacity effects of State RPS programs included in the reference case will extend beyond 2010, adding 97 megawatts of additional generating capacity by 2020.

The results of the high renewables case suggest that technology improvements would increase generation from some renewable sources (Figure 82) but would not alter the dominant role of fossil fuels in the U.S. fuel mix overall. Generation from nonhydroelectric renewables is projected at 299 billion kilowatthours in 2020, compared with 156 billion in the reference case. The increment in generation is mostly from wind, biomass, and geothermal resources, which displace coal and natural gas. Wind capacity in 2020 is over 22 gigawatts, compared with 3.6 gigawatts in the reference case (Figure 83). As a result, the share of total electricity generation from nonhydroelectric renewables increases to 6.2 percent, compared with 3.2 percent in the reference case, and carbon emissions in 2020 are reduced by 70 million tons, or 3.5 percent.

Lower Costs Could Boost Wind-Powered Generating Capacity

Figure 83. Wind-powered electricity generating capacity in two cases, 1985-2020 (gigawatts)



The *AEO99* projections show a growing number of State programs in support of renewable energy investment (see "Issues in Focus," page 22). The programs, reflecting both energy and environmental interests, are intended to spur private investment despite the increasingly competitive marketplace. Although the long-term implications of mandates, renewable portfolio standards (RPS), green power marketing, system benefits funds, and other State actions are not entirely clear, they are having the immediate effect of increasing renewable generating capacity. Whereas last year no quantifiable State RPS programs existed, *AEO99* projects 638 megawatts of new generating capacity as the result of RPS programs in Arizona, Connecticut, Massachusetts, and Nevada, as well as an additional 579 megawatts from a separate initiative in California.

Almost 64 percent of the known new capacity from mandates, State RPS programs, and the California initiative is from wind; biomass represents 14 percent, and other renewable energy technologies represent the rest in roughly equal shares (although solar thermal represents less than 3 percent). Most is expected to be in operation before 2005. Actual additions could well be greater, reflecting new capacity in States currently in the process of identifying winning technologies; the additional capacity effects should extend well beyond 2005.