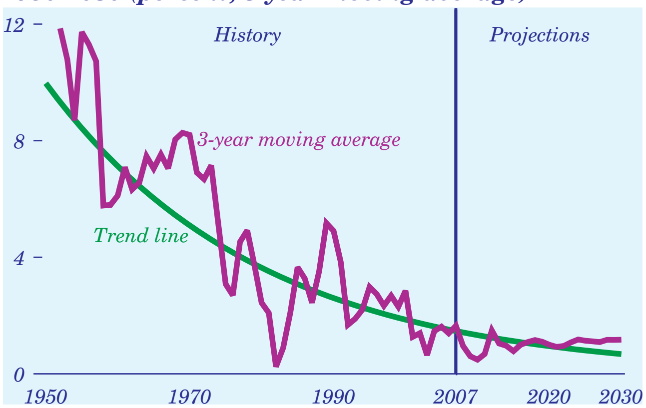
Rate of Electricity Demand Growth Slows, Following the Historical Trend

Figure 54. U.S. electricity demand growth, 1950-2030 (percent, 3-year moving average)



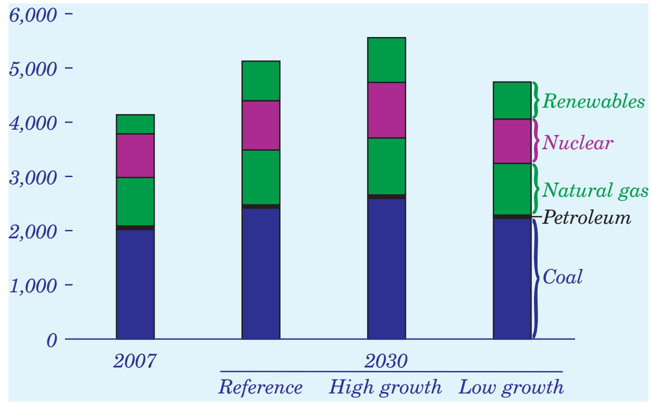
Electricity demand fluctuates in the short term in response to business cycles, weather conditions, and prices. Over the long term, however, electricity demand growth has slowed progressively by decade since 1950, from 9 percent per year in the 1950s to less than 2.5 percent per year in the 1990s. From 2000 to 2007, increases in electricity demand averaged 1.1 percent per year. The slowdown in demand growth is projected to continue over the next 23 years (Figure 54), as a result of efficiency gains in response to rising energy prices and new efficiency standards for lighting, heating and cooling, and other appliances.

In the reference case, electricity demand increases by 26 percent from 2007 to 2030, or by an average of 1.0 percent per year. The largest increase is in the commercial sector (38 percent), where service industries continue to lead demand growth, followed by the residential sector (20 percent) and the industrial sector (7 percent). Population growth and rising disposable incomes increase the demand for products, services, and floorspace, and ongoing population shifts to warmer regions increase the use of electricity for space cooling.

From 2007 levels, electricity demand increases by 36 percent in the high growth case, to 5,323 billion kilowatthours in 2030, compared with an increase of 16 percent in the low growth case, to 4,518 billion kilowatthours in 2030. Plug-in electric hybrid vehicles are not expected to reverse the trend of slowing growth in electricity demand, which increases by only 0.1 percent for every 1 million PHEV-40 vehicles in operation.

Coal-Fired Power Plants Provide Largest Share of Electricity Supply

Figure 55. Electricity generation by fuel in three cases, 2007 and 2030 (billion kilowatthours)



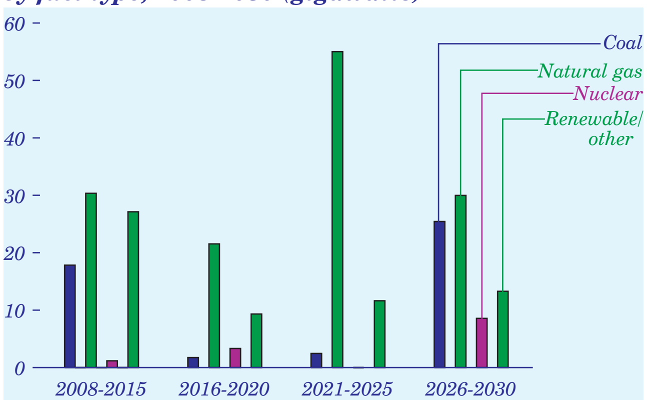
Coal continues to provide the largest share of energy for U.S. electricity generation in the *AEO2009* reference case, with only a modest decrease from 49 percent in 2007 to 47 percent in 2030. Total electricity generation at coal-fired power plants in 2030 is 19 percent higher than the 2007 total (Figure 55). Growth in coal-fired generating capacity is limited by concerns about GHG emissions and the potential for mandated limits, but existing plants continue to be used intensively.

Concerns about GHG emissions have little effect on construction of new capacity fueled by natural gas. The natural gas share of generation increases to 21 percent in 2027, before dropping to 20 percent in 2030, about the same as in 2007. Generation from nuclear power increases by 13 percent from 2007 to 2030, as addition of new units and uprates at existing units increase overall capacity and generation. The nuclear share of total generation falls somewhat, however, from 19 percent in 2007 to 18 percent in 2030. Renewable generation, supported by Federal tax incentives and State renewable programs, increases by more than 100 percent from 2007 to 2030, when it accounts for 14 percent of total generation.

Projected growth in demand for electricity varies with different assumptions about future economic conditions. In 2030, total generation in the high economic growth case is 9 percent above the reference case projection, and in the low economic growth case it is 7 percent below the reference case.

Most New Capacity Uses Natural Gas as Fewer Coal-Fired Plants Are Added

Figure 56. Electricity generation capacity additions by fuel type, 2008-2030 (gigawatts)



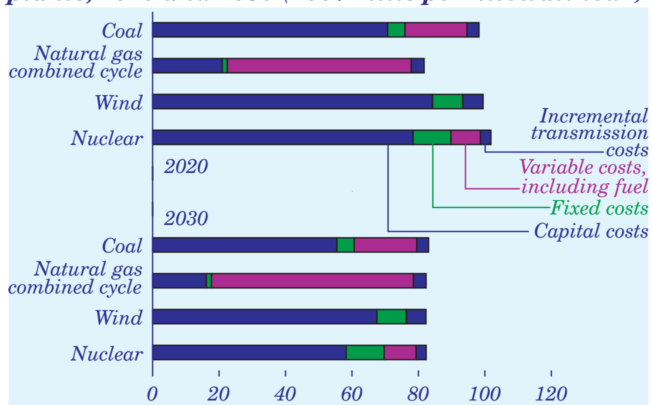
Decisions to add capacity and the choice of fuel type depend on electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different options, fuel prices, and the availability of Federal tax credits for some technologies. With growing electricity demand and the retirement of 30 gigawatts of existing capacity, 259 gigawatts of new generating capacity (including end-use CHP) will be needed between 2007 and 2030.

Natural-gas-fired plants account for 53 percent of capacity additions in the reference case, as compared with 22 percent for renewables, 18 percent for coal-fired plants, and 5 percent for nuclear (Figure 56). Escalating construction costs have the largest impact on capital-intensive technologies, including renewables, coal, and nuclear; but Federal tax incentives, State energy programs, and rising prices for fossil fuels increase the cost-competitiveness of renewable and nuclear capacity. In contrast, uncertainty about future limits on GHG emissions and other possible environmental regulations (reflected in the *AEO2009* reference case by adding 3 percentage points to the cost of capital for new coal-fired capacity) reduces the competitiveness of coal.

Projected capacity additions also are affected by demand growth and by fuel prices. Reflecting slower and faster growth in demand for electricity, capacity additions from 2007 to 2030 total 184 gigawatts and 350 gigawatts in the low and high economic growth cases, respectively. The higher fuel costs in the *AEO-2009* high oil price case lead to fewer additions of natural-gas-fired plants, because fuel costs make up a relatively large share of their total expenditures.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 57. Levelized electricity costs for new power plants, 2020 and 2030 (2007 mills per kilowatthour)



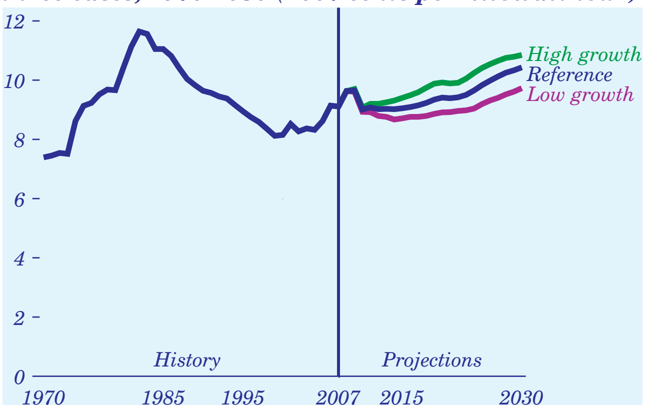
Technology choices for new generating capacity are made to minimize costs while meeting local and Federal emissions constraints. Capacity expansion decisions consider capital, operating, and transmission costs. Typically, coal-fired, nuclear, and renewable plants are capital-intensive, whereas operating (fuel) expenditures account for most of the costs associated with natural-gas-fired capacity (Figure 57) [*96*]. Capital costs depend on such factors as interest rates and cost-recovery periods. Fuel costs can vary according to plant operating efficiency, resource availability, and transportation costs.

Regulatory uncertainty affects capacity planning decisions. Unless they are equipped with CCS equipment, new coal-fired plants could incur higher costs as a result of higher expenses for siting and permitting. Because nuclear and renewable power plants (including wind plants) do not emit GHGs, however, their costs are not directly affected by regulatory uncertainty.

Capital costs can decline over time as developers gain experience with a given technology. In the *AEO2009* reference case, capital costs are adjusted upward initially, to reflect the optimism inherent in early public estimates of project costs. The costs decline as project developers gain experience, and the decline continues at a progressively slower rate as more units are built. Operating efficiencies also are assumed to improve over time, and variable costs could therefore be reduced unless increases in fuel costs exceed the savings from efficiency gains.

Electricity Prices Moderate in the Near Term, Then Rise Gradually

Figure 58. Average U.S. retail electricity prices in three cases, 1970-2030 (2007 cents per kilowatthour)



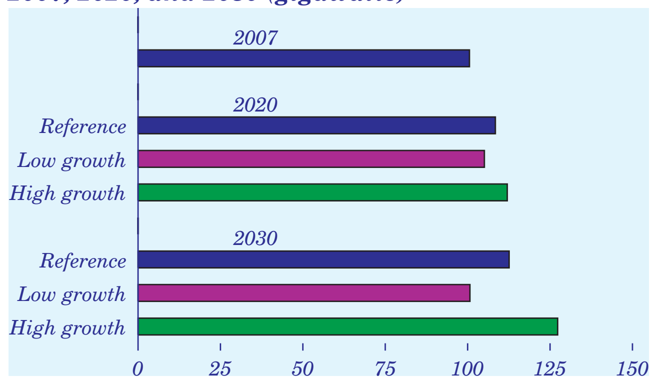
In recent years, real electricity prices (in 2007 dollars) have increased sharply, as fuel costs and capital costs have risen rapidly and restructuring initiatives that constrained price increases have ended. In the *AEO2009* reference case, real electricity prices fall in the near term when fuel prices decline during the economic slowdown. With economic recovery, real electricity prices stabilize at 9.0 cents per kilowatthour in 2010, then remain at that level for several years, while fuel prices remain relatively low and new coal- and natural-gas-fired capacity comes on line. Real electricity prices begin to rise steadily after 2015, as fuel prices increase more rapidly and the need for new capacity grows. Much of the new renewable capacity is required by State renewable mandates.

Real retail electricity prices increase to 10.4 cents per kilowatthour in 2030 in the reference case (Figure 58). They are higher in the high economic growth case, reaching 10.8 cents per kilowatthour in 2030 as stronger economic growth leads to more rapid growth in electricity demand. Electricity prices are lower in the low economic growth case, at 9.7 cents per kilowatthour in 2030.

Transmission costs, while remaining a relatively small component of delivered electricity prices, increase by 35 percent from 2007 to 2030 because of the additional investment needed to meet electricity demand growth, alleviate existing transmission constraints and bottlenecks, facilitate the operation of competitive wholesale energy markets, and link new generation from remote wind facilities with demand centers.

EPACT2005 Tax Credits Are Expected To Stimulate Some Nuclear Builds

Figure 59. Electricity generating capacity at U.S. nuclear power plants in three cases, 2007, 2020, and 2030 (gigawatts)

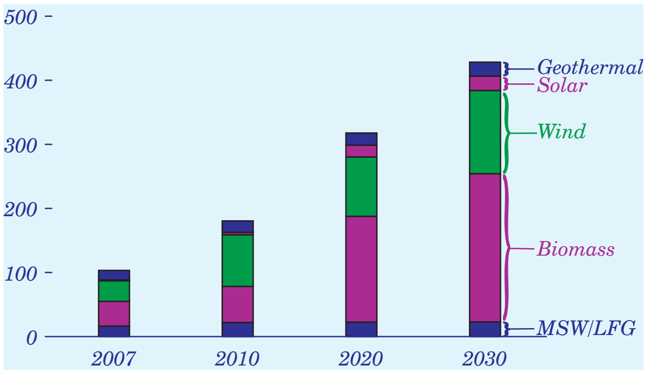


In the *AEO2009* reference case, nuclear power capacity increases from 100.5 gigawatts in 2007 to 112.6 gigawatts in 2030, including 3.4 gigawatts of expansion at existing plants, 13.1 gigawatts of new capacity, and 4.4 gigawatts of retirements. The reference case includes a second unit in 2014 at the Watts Bar site, where construction was halted in 1988 after being partially completed. Rising costs for construction materials have greatly increased the estimated cost of new nuclear plants, which when combined with the current instability of financial markets makes new investments in nuclear power uncertain. In the reference case, some 10 new nuclear power plants are completed through 2030. The first few are eligible for the EPACT2005 PTC. Most existing nuclear units continue to operate through 2030, based on the assumption that they will apply for and receive operating license renewals. Seven units, totaling 4.4 gigawatts, are retired after 2028, when they reach the end date of their original licenses plus a 20-year renewal.

In the *AEO2009* projections, nuclear capacity additions vary with assumptions about overall demand for electricity and the prices of other fuels (Figure 59). The amount of nuclear capacity added also is sensitive to assumptions about future plans and policies for limiting or reducing GHG emissions. Across the oil price and economic growth cases, nuclear capacity additions from 2007 to 2030 range from 1 to 28 gigawatts. In the low economic growth case, with falling electricity demand and rising interest rates, new nuclear plants are not economical. More new nuclear capacity is built in the high growth and high oil price cases, because overall capacity requirements are higher and/or alternatives are more expensive.

Biomass and Wind Lead Projected Growth in Renewable Generation

Figure 60. Nonhydroelectric renewable electricity generation by energy source, 2007-2030 (billion kilowatthours)

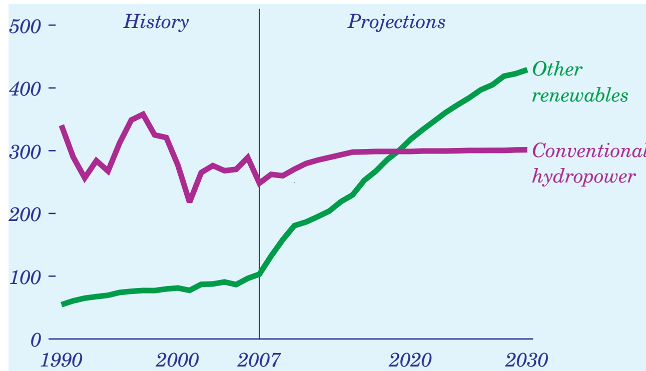


The potential for growth in electricity generation from wind power depends on a variety of factors, including fossil fuel costs, State renewable energy programs, technology improvements, access to transmission grids, public concerns about environmental and other impacts, and the future of the Federal PTC for wind, which is scheduled to expire at the end of 2009. Other renewable technologies are guaranteed a tax credit for an additional year. In the *AEO2009* reference case, generation from wind power increases from 0.8 percent of total generation in 2007 to 2.5 percent in 2030 (Figure 60). Generation from biomass, both dedicated and co-firing, grows from 39 billion kilowatthours in 2007 (0.9 percent of the total) to 231 billion kilowatthours (4.5 percent) in 2030. Generation from geothermal facilities also increases but at such a slow rate that it does not gain market share. Current assessments show limited potential for expansion at conventional geothermal sites. Enhanced geothermal development remains economically infeasible.

The principal reason for the robust growth of renewable electricity generation in the end-use sectors, which is included in the totals above, is the EISA2007 renewable fuels mandate. Biorefineries producing cellulosic ethanol use residues from the biomass feedstock for electricity production. Generation from biomass comprises nearly 80 percent, or 91 billion kilowatthours, of end-use renewable electricity in 2030. Solar technologies in general remain too costly for grid-connected applications, but demonstration programs and State policies support some growth in central-station solar PV, and small-scale, customer-sited PV applications grow rapidly [*97*].

Technology Advances, Tax Provisions Increase Renewable Generation

Figure 61. Grid-connected electricity generation from renewable energy sources, 1990-2030 (billion kilowatthours)

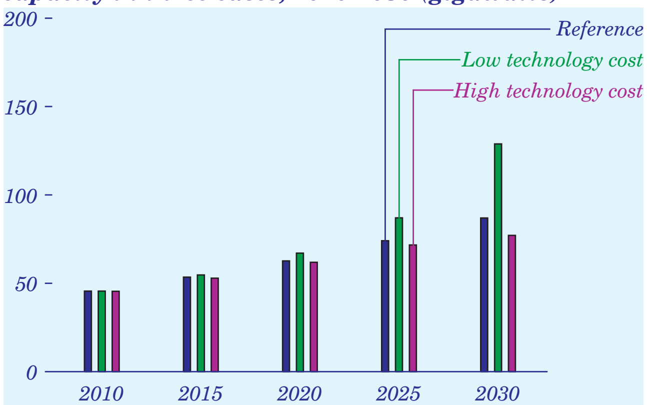


The *AEO2009* reference case includes both State RPS requirements and a risk premium on high-carbon generating technologies. As a result, total renewable electricity generation grows by nearly 380 billion kilowatthours, to 730 billion kilowatthours (14.2 percent of total domestic power production) in 2030. Environmental concerns and a scarcity of new large-scale sites limit the growth of conventional hydropower, and from 2007 to 2030 its share of total generation remains between 6 percent and 7 percent. Generation from nonhydroelectric alternatives increases, bolstered by legislatively mandated State RPS programs, technology advances, and State and Federal supports (Figure 61). Although the Federal PTC is assumed to expire after 2009 for wind and after 2010 for other renewables, nonhydropower renewable generation increases from 2.5 percent of total generation in 2007 to 8.3 percent in 2030.

Wind and biomass are the largest sources of electricity among the nonhydropower renewables. Initially helped by the Federal PTC, their growth continues as States meet their RPS requirements and more States enact RPS programs each year. Central-station solar is also growing rapidly in California. Although the technology remains costly, several credible project announcements have been made that would lead to capacity expansion in the hundreds of megawatts. Moreover, as States continue to organize regional climate pacts, renewable generation will become more prominent in carbon-constrained regions. The Northeast RGGI is the only such program included in the *AEO2009* reference case, but western States are moving forward quickly with their own programs.

Higher or Lower Costs Affect Trends in Renewable Generation Capacity

Figure 62. Nonhydropower renewable generation capacity in three cases, 2010-2030 (gigawatts)

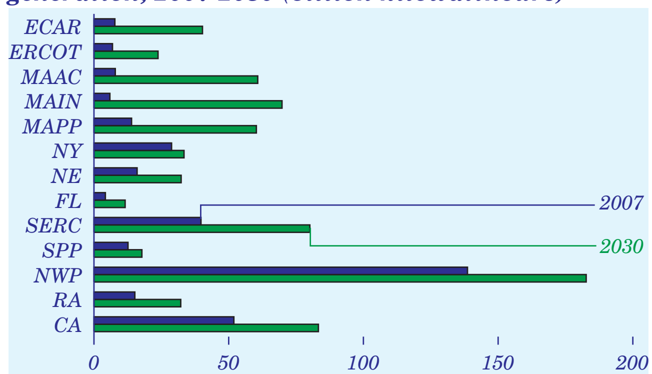


If the costs of renewable generation technologies decline significantly faster than projected in the *AEO-2009* reference case, there may be more new renewable capacity than is needed to meet State renewable generation mandates. The low renewable technology cost case assumes costs 25 percent lower than in the reference case in 2030, resulting in 38 percent more new wind capacity and 200 percent more new dedicated biomass capacity. New end-use solar capacity in 2030 is 49 percent above the reference case level, although the technology remains too expensive for widespread use in bulk power markets; geothermal, hydroelectric, and municipal solid waste capacity shows little change, because economical resources are limited. A significant increase in dedicated biomass capacity in the low cost case draws biomass away from less efficient co-firing operations and helps producers meet State RPS requirements.

In the *high renewable technology cost case*, the costs for renewable capacity remain at the reference case levels and "dedicated energy crops" are not developed, resulting in slightly less new renewable capacity in 2030 than in the reference case (Figure 62). State mandates still are expected to guarantee a significant amount of growth in renewable capacity, however, even with the higher costs. In the high cost case, biomass co-firing operations make a larger contribution to RPS compliance than in the reference case. Although many State RPS laws include cost containment measures that may limit overall compliance if renewable generation is more expensive than projected in the reference case, many of those provisions either are discretionary or cannot be analyzed fully in the high cost case.

State Portfolio Standards Increase Generation from Renewable Fuels

Figure 63. Regional growth in nonhydroelectric renewable electricity generation, including end-use generation, 2007-2030 (billion kilowatthours)



As of early November 2008, 28 States and the District of Columbia had legislatively mandated RPS programs. The mandatory programs are included in the reference case, but States' voluntary goals are not. Because NEMS does not provide projections at the State level, the reference case assumes that most States will reach their goals within each program's legislative framework, and the results are aggregated at the regional level. In some States, however, compliance could be limited by authorized funding levels for the programs. For example, California is not expected to meet its renewable energy targets because of limits on the authorized funding for its RPS program.

By region, the fastest growth in nonhydroelectric renewable generation is projected for MAIN (Figure 63). The largest share of wind power is in the MAIN region, which includes Illinois, Wisconsin, and parts of Michigan and Missouri. In Texas, generation from wind power grows until the Federal PTC expires on December 31, 2010, and resumes growth after 2020, when natural gas prices begin to rise more rapidly. Solar and geothermal energy are used in the Southwest. Biomass generates most of the required renewable energy in the Mid-Atlantic region, which in 2030 contains nearly 53 percent of the Nation's dedicated biomass capacity.

Most NEMS regions include at least one State with an RPS program (see Figure F2 in Appendix F for a map of the regions). The only area without widespread RPS programs is the Southeast, where North Carolina is the only State with an enforceable RPS.