Market for New Coal Powerplant Technologies in the U.S.
1997 Annual Energy Outlook Results

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Abstract: Over the next 20 years, the combination of slow growth in the demand for electricity, even slower growth in the need for new capacity, especially baseload capacity, and the competitiveness of new gas-fired technologies limits the market for new coal technologies in the U.S. In the later years of the 1997 Annual Energy Outlook projections, post-2005, when a significant amount of new capacity is needed to replace retiring plants and meet growing demand, some new coal-fired plants are expected to be built, but new gas-fired plants are expected to remain the most economical choice for most needs. The largest market for clean coal technologies in the United States maybe in retrofitting or repowering existing plants to meet stricter environmental standards, especially over the next 10 years. Key uncertainties include the rate of growth in the demand for electricity and the level of competing fuel prices, particularly natural gas. Higher then expected growth in the demand for electricity and/or relatively higher natural gas prices would increase the market for new coal technologies.

I. Key 1997 Annual Energy Outlook Results

Over the next 20 years the demand for electricity is expected to continue to increase with economic growth (Figure 1). However, the combination of increased market saturation of electric appliances, improvements in equipment efficiency, utility investments in demand-side management programs and legislation establishing more stringent equipment efficiency standards has slowed the rate of growth from the level seen in the 1960s and 1970s. Overall the demand for electricity is projected to grow 1.5 percent annually, with the residential and industrial sales growing faster than commercial sales (Figure 2).

The need for new capacity, especially baseload capacity, is expected to grow slower than total demand. Between 1995 and 2015 total U.S. generating capacity increases from 767 to 970 gigawatts, an annual rate of increase of 1.2 percent. However, due to the expected retirements of 38 gigawatts of existing nuclear capacity and 71 gigawatts of existing fossil-steam capacity, total capacity additions amount to 310 gigawatts over the next 20 years (Figure 3). Nuclear plants are assumed to retire at the end of their 40-year license period or before if their operating and maintenance costs exceed 4.0 cents per kilowatt hour. Fossil-steam plant retirements include reported retirement plans from utilities and the retirement of high operating cost units that would not be competitive in a deregulated environment.

Figure 1. Population, Gross Domestic Product, and Electricity Sales Growth, 1960-2015 (Index, 1960 = 100)

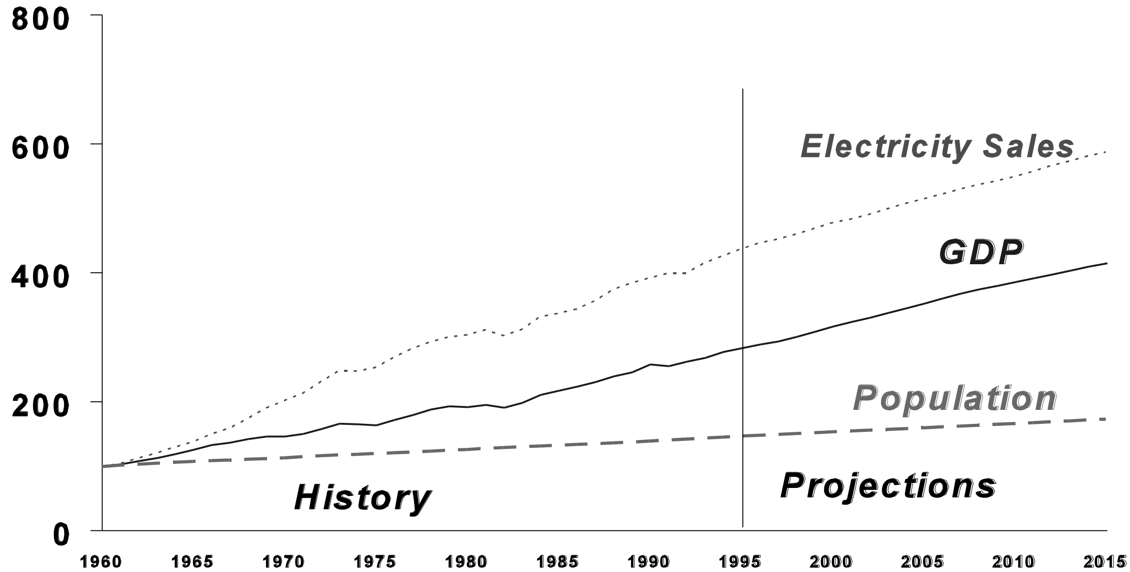


Figure 2. Electricity Sales by Sector, 1970 - 2015 (Billion kilowatthours)

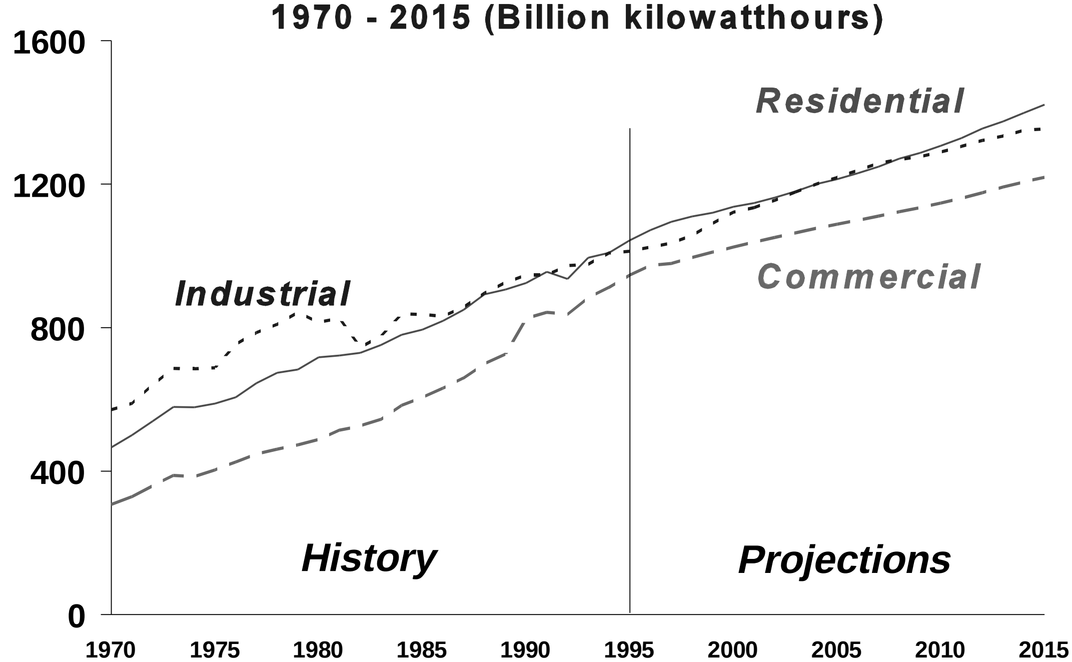
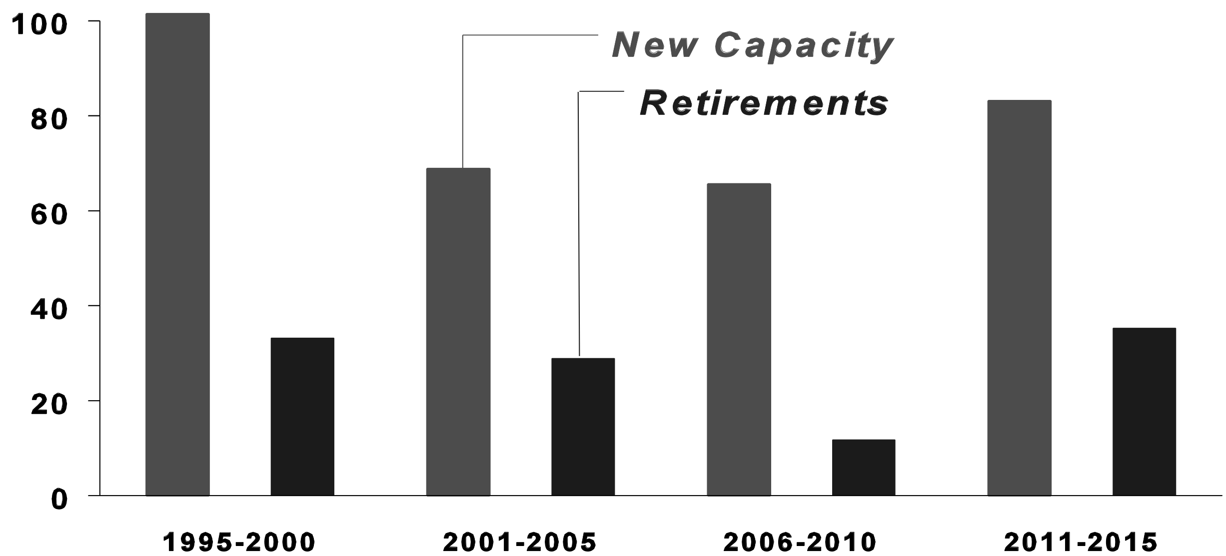


Figure 3. New Generating Capacity and Retirements, 1990 - 2015 (Gigawatts)



Natural gas-fired combustion turbines and combined-cycle units are expected to dominate new plant additions, especially in the near-term (Figure 4). About 80 percent of the capacity additions over the 1995 through 2015 period are projected to be gas-fired. Coal-fired and renewable (and other) plants account for the remaining capacity (11 and 8 percent, respectively). In the near term, between 1995 and 2000, new capacity is expected to be built to meet peaking needs. As a result, 65 percent of the gas-fired capacity built in that period are simple combustion turbines while the rest are combined-cycle plants. This pattern reverses itself in the last five years of the forecast when new plants are needed to serve growing baseload and intermediate demands. Over this 5 year period combined-cycle plants account for about 75 percent of the gas-fired plants added.

It is also during the later years of the forecast, 2005 to 2015, when most of the new coal plants projected to be added are brought on line. About 70 percent of the 37 gigawatts of coal plants projected to be built between 1995 and 2015 are brought on-line in 2005 and later. Over the 20 years of the projections, gas and coal prices to powerplants slowly diverge, with gas prices rising at approximately 1 percent per year (most of this increase occurs after 2005) while coal prices decline at a rate of 0.9 percent annually (Figure 5). In some regions of the country this widening fuel cost differential is large enough to allow new coal plants to be competitive with gas plants even though they cost much more to build. The vast majority, approximately 75 percent, of the

Figure 4. Electricity Generation and Cogeneration Capacity Additions by Fuel Type, 1995 - 2015 (Gigawatts)

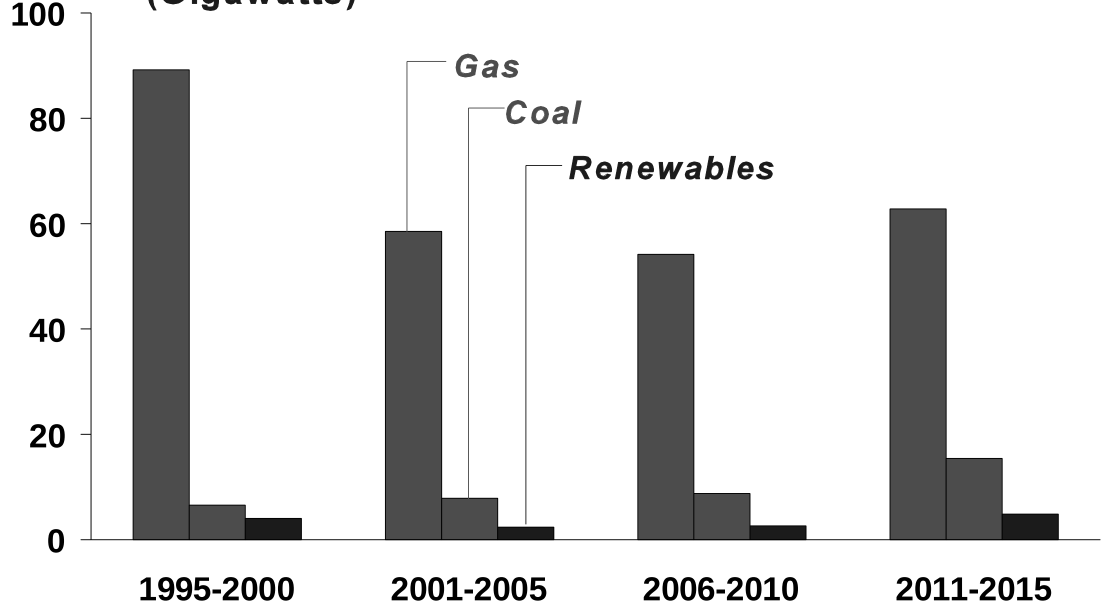
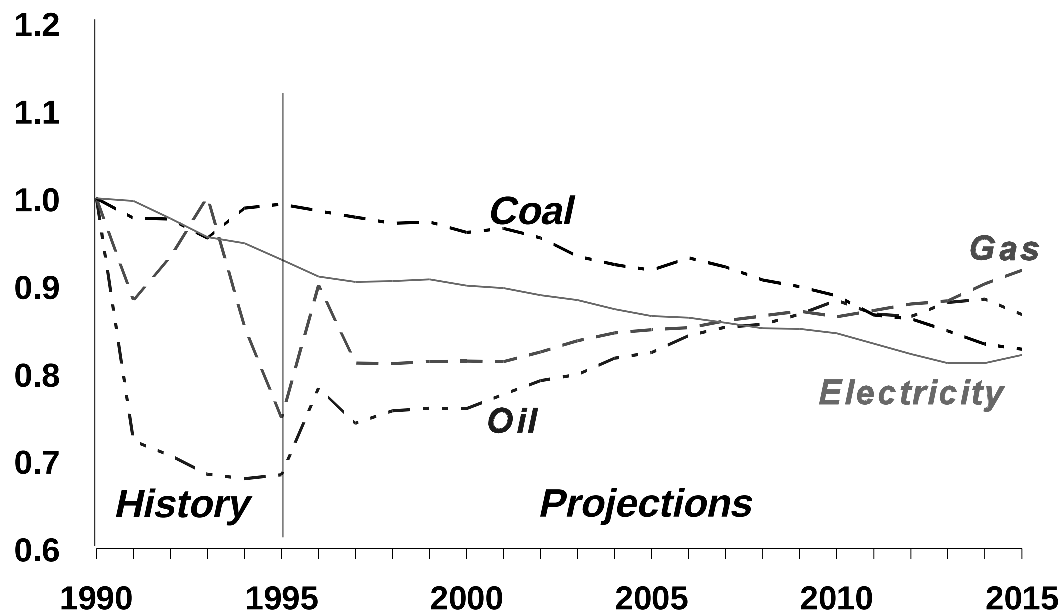


Figure 5. Fuel Prices to Electricity Suppliers and Electr Prices, 1990 - 2015 (Index, 1990 = 1.0)

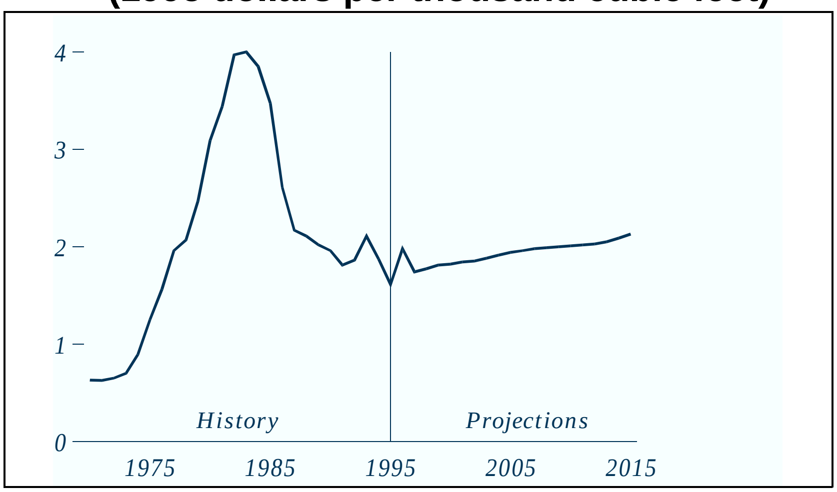


coal plants built are expected to be conventional pulverized coal plants with the remaining being integrated coal gasification plants (IGCC).[1]

II. Natural Gas, Coal, and Electricity Prices

Wellhead prices for natural gas in the lower 48 States increase by 1.4-percent annually in the reference case (Figure 6) reaching $2.13 per thousand cubic feet (in 1995 dollars) in 2015. The price increases reflect the rising demand for natural gas and its impact on the natural progression of the discovery process from larger and more profitable fields to smaller, less economical ones. In *AEO97*, technological progress arrests and even reverses declining finding rates in some regions. As a result, natural gas production is increased, with less drilling activity and at lower cost, particularly in offshore regions, where technological progress has a greater impact on the development of relatively immature fields. In addition, competition within the industry and projections of lower interest rates reduce the costs of transmission and distribution, offsetting the projected increase in wellhead prices, so that the average delivered price of natural gas declines between 1995 and 2015 at an average rate of 0.2 percent.

Figure 6. Lower 48 Natural Gas Wellhead Prices, 1970-2015 (1995 dollars per thousand cubic feet)



Coal minemouth prices are projected to decline in the forecast as a result of increasing productivity, a shift to western production, and competitive pressures on labor costs. In *AEO97*, the average minemouth price of coal is projected to be $15.46 per ton in 2015 (Figure 7). Lower coal transportation rates--leading to higher production from western mines, where production costs are lower than in the East--are the primary reason for the lower minemouth prices.

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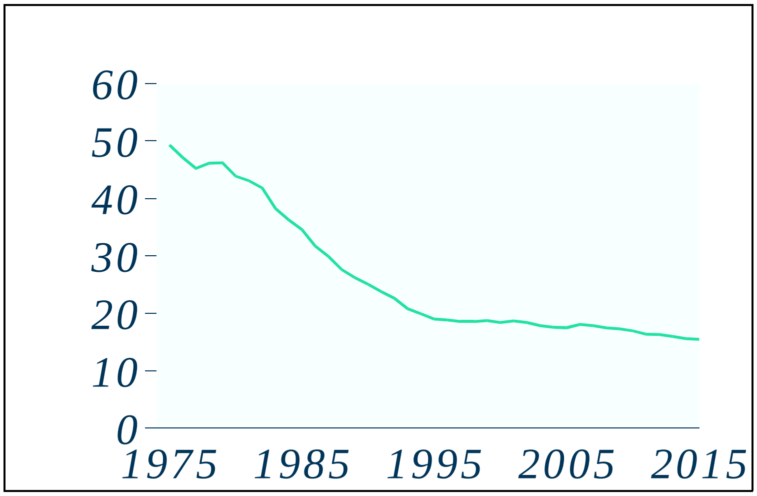
[1] The Electricity Market Module allows the representation of two coal technologies. The IGCC technology was used as representative of an advanced coal technology.

Figure 7. Coal Minemouth Price Projections, 1995-2015 (1995 dollars) (Dollars per ton)



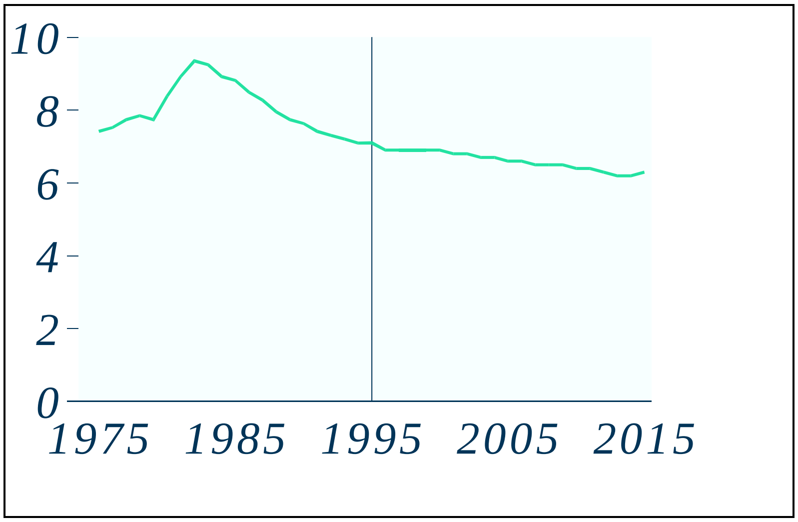
The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Changes in fuel costs affect transportation rates, but fuel efficiency also grows with other productivity improvements in the forecast. As a result, average coal transportation rates decline by 0.9 percent a year between 1995 and 2015. The most rapid declines are likely to occur in routes that originate in coalfields with the greatest production growth. Railroads are likely to reinvest profits from increasing coal traffic to reduce future costs and rates in regions with the best outlook. Thus, coalfields that are most successful at improving productivity and, therefore, lowering minemouth prices are likely to obtain the lowest transportation rates and, consequently, the largest markets at competitive delivered prices.

Regional differences in production and transportation costs are already affecting coal distribution patterns. Western coal is gaining share in midwestern and southeastern markets, and coal for export is moving along different domestic routes. Retirements of barge capacity have exceeded replacements in recent years, and the resulting increase in inland barge rates has caused some traffic to shift to rail or Great Lakes vessels for all or part of the journey from mines to U.S. ports of exit. In spite of railroad mergers and consolidation in the barge industry, real coal transportation costs are projected to continue their historical decline, as competition among surviving carriers forces technological improvements.

Average electricity prices also decline through 2015. The average price in 2015 is projected to be 6.3 cents per kilowatt hour, as a result of lower projected fossil fuel prices and anticipated industry restructuring (Figure 8). Increased competition in the electricity industry is assumed to lead to lower operating and maintenance costs, lower general and administrative costs, early retirement of inefficient units, and other cost reductions. The *AEO97* assumes that operating and

maintenance expenses decline by 2.5 percent annually from 1997 to 2007, continuing the trend of the previous 10-year period. Also, expenses charged to general and administrative functions (billing, salaries, and benefits) are assumed to drop by 25 percent during the same period as generators position themselves for increased competition. *AEO97* reflects the evolving trend of competition within electricity markets but does not include the full impacts of restructuring and deregulation. Although the projections include the recent actions taken by the Federal Energy Regulatory Commission on open access, specific actions to be taken by State public utility commissions and their timing are not yet known and have not been incorporated.

Figure 8. Electricity Price Projections, 1995-2015
(1995 dollars) (Cents per kilowatt hour)



III. Economics of Coal versus Gas Technologies

The expected increasing reliance on gas-fired plants is driven by their economic competitiveness relative to other generating options. Over the last decade technological innovations in natural gas recovery and combustion have combined to lower expectations of future natural gas prices and dramatically increase the combustion efficiency of new gas plants. The result is that gas-fired plants are currently the economical choice for most applications. Figure 9 and Table 1 show the component costs of producing power from a pulverized coal plant and an advanced gas-fired combined cycle plant.[2] As shown the two technologies differ significantly in what drives their total levelized costs. Total coal plant costs are dominated by their capital costs while gas-fired combined-cycle plant total costs are dominated by fuel costs. Overall 55 to 60 percent of a coal plant total costs are related to its construction costs, while 62 to 68 percent of a gas combined-cycle plants costs are accounted for by fuel expenses.

Table 1. Costs of Producing Electricity From New Plants, 2000 and 2015

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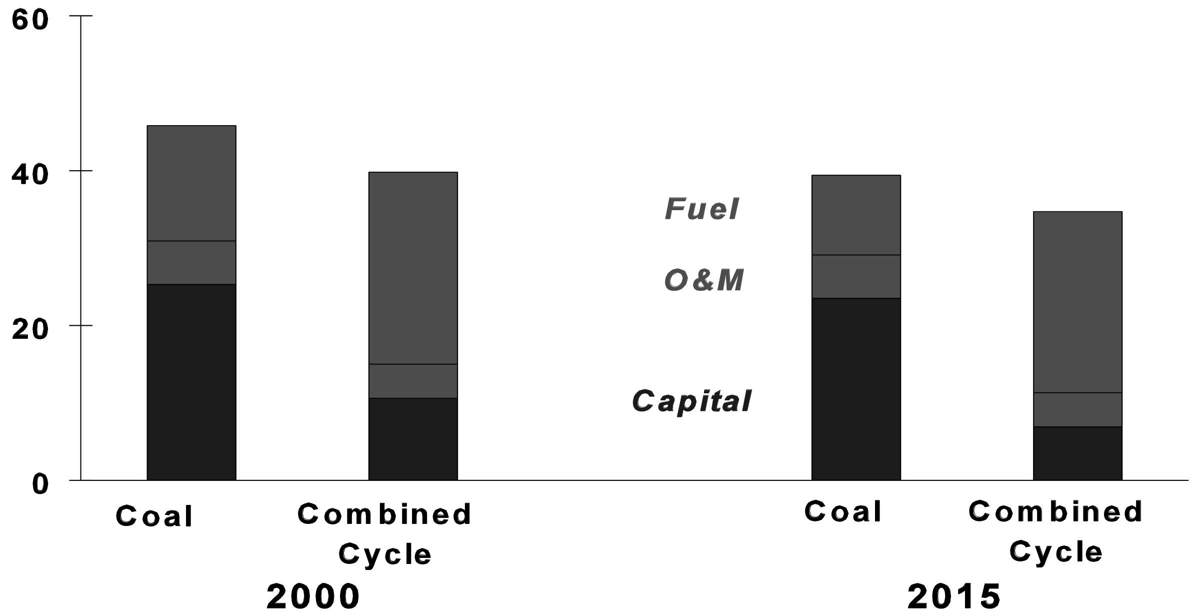
[2]The figures shown are nationwide averages. In some regions coal is more competitive while in others it is less competitive.

Figure 9. Levelized Cost of Electricity, 2000 and 2015 (Mills per Kilowatthour)



	2000	2000	2015	2015
	Conventional Pulverized Coal	**Advanced Combined-Cycle**	**Conventional Pulverized Coal**	**Advanced Combined-Cycle**
	1995 mills per kilowatt hour			
Capital	25.3	10.6	23.5	6.9
O&M	5.6	4.4	5.6	4.4
Fuel	14.9	24.8	10.3	23.4
Total	**45.8**	**39.9**	**39.4**	**34.5**
	Btu per kilowatt hour			
Heatrate	9,928	6,985	9,463	5,700

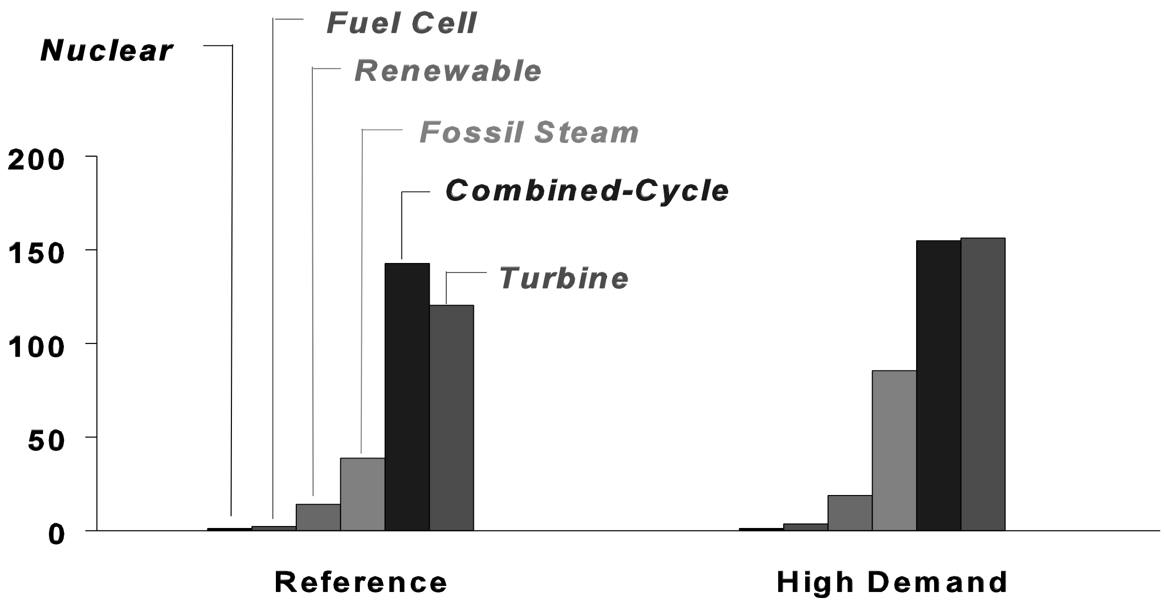
IV. Uncertainties and Impacts of Electricity Market Restructuring

Among the uncertainties with respect to the size of the market for new coal powerplant technologies are the rate of growth of the demand for electricity, the prices of competing fuels, especially natural gas and the rate of technological innovation (improvements in the cost and performance of advanced generating technologies). The restructuring of the electricity market could also have a significant impact, but its impact would affect the demand for electricity and fuel prices. While the rate of growth in the demand for electricity has slowed over the last 30 years, over the last 15 years it has averaged 2.4 percent per year. It is expected that the long-term slowing will continue, but it is possible that new electricity uses, tomorrow's VCRs, fax machines, and computers, will continue to evolve and maintain the rate of growth seen in recent years. To test the sensitivity of the results to higher electricity demand growth a case was prepared assuming a rate of growth in the demand for electricity of 2.0 percent annually, much higher than the 1.5 percent annual growth rate in the reference case. The impact on the need for new capacity is large, over 100 gigawatts of capacity beyond that required in the reference case is brought on line (Figure 10). The higher demand growth increases the market for all capacity types, but coal plants gain the most. Between the reference case and the high demand case the amount of new coal plants added more than doubles, reaching a cumulative total of over 80 gigawatts between 1995 and 2015. The reasons for this are twofold. First, the higher demand level increases the total need for new capacity. And, second, the higher demand level has a stronger impact on natural gas prices than it does on coal prices making new coal plants relatively more economically attractive.

If, as many expect, the restructuring of U.S. electricity markets results in lower electricity prices the demand for electricity is likely to be somewhat higher, though how much is unclear. However, this may not result in increased needs for capacity. The need for capacity is determined by the highest demand for electricity occurring during a given period, the so called peak demand. Prices during these supply constrained time periods may actually be much higher in a restructured electricity market than they are today and consumers may respond by reducing their consumption during these time periods while increasing it in lower cost time periods. The net result of this shifting demand could be increasing utilization of existing lower cost facilities, but a reduction in the need for new capacity for some time.

Two additional cases were prepared to assess the sensitivity of the results to the rate of technological improvement. In the reference case, higher initial capital costs are assumed for new, advanced generating facilities, to account for both technological optimism and inexperience in constructing the new designs. The costs are assumed to decline as a function of market penetration. To examine the effects of these assumptions, a high technology case was developed, with capital cost reductions due to learning effects assumed to be 50 percent greater than in the reference case, and optimism factors (which increase the cost of the earliest units constructed) assumed to be 50 percent lower than in the reference case. These assumptions result in costs for advanced technologies being approximately 12 percent lower than in the reference case. A low technology case was also prepared assuming that only those technologies available (beyond the initial testing and pilot program phase) as of 1996 are permitted to compete. The most

Figure 10. New Generating Capacity by Fuel Type in Two Demand Cases, 1995-2015 (Gigawatts)



significant result between the low and high technology cases is the shift from conventional gas-fired technologies to advanced gas-fired technologies (Figure 11). Advanced coal and renewables plants only penetrate by small amounts.

Two alternative *AEO97* analyses--the high and low nuclear cases--show how changing assumptions about the operating lifetimes of nuclear plants affect the reference case forecast of nuclear and fossil capacity. The low nuclear case assumes that, on average, all units are retired 10 years before the end of their 40-year license periods (93 units by 2015). Early shutdowns could be caused by unfavorable economics, waste disposal problems, or physical degradation of the units. The high nuclear case assumes 10 additional years of operation for each unit (only 4 units retired by 2015), suggesting that license renewals would be permitted. Conditions favoring that outcome could include continued performance improvements, a solution to the waste disposal problem, or stricter limits on emissions from fossil-fired generating facilities. In the low nuclear case, more than 100 new fossil-fueled units (assuming an average unit size of 300 megawatts) would be built to replace retiring nuclear units. The new capacity would be split mainly between coal-fired (37 percent) and combined-cycle (47 percent) units. The additional fossil-fueled capacity would produce 43 million metric tons of carbon emissions above those in the *AEO97* reference case, in 2015 (1,799 million metric tons total, 678 million metric tons from electric generators). Also, 3 gigawatts of additional new renewable and fuel cell capacity would be built. In the high nuclear case, 32 gigawatts of new capacity additions--mostly fossil-fueled plants--are avoided, as compared with those in the *AEO97* reference case, and carbon emissions are reduced by 29 million metric tons (4 percent of total emissions by electricity generators).

Figure 11. Unplanned Capacity Additions in Three Technology Cases, 1995-2015 (Gigawatts)

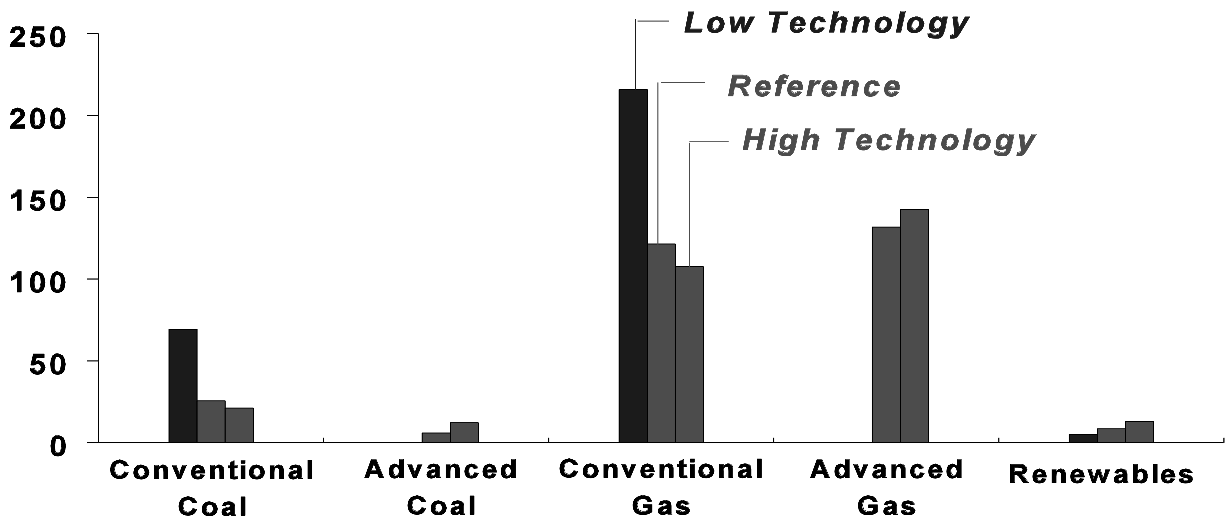
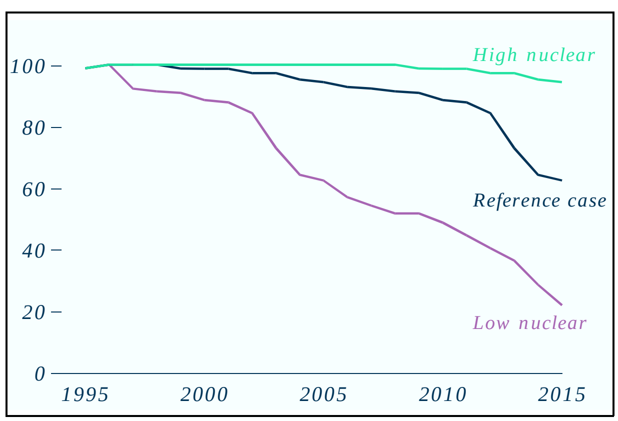


Figure 12. Operable Nuclear Capacity in Three Nuclear Cases, 1995-2015 (Gigawatts)



V. Conclusions

Over the next 10 to 20 years natural gas-fired generation technologies are expected to meet most of the needs for new capacity. Their relatively low capital costs, high thermal efficiencies and low emissions rates make them very attractive. New coal fired technologies are expected to account for around 11 percent of new capacity added, though that number could be larger if the demand for electricity or natural gas prices prove higher than expected. The major market of new clean coal technologies in the U.S. may be in retrofitting or repowering existing plants to meet new environmental requirements.

Figure Notes

Figure 1. Population, Gross Domestic Product, and Electricity Sales Growth, 1960-2015
History: Energy Information Administration, *Annual Energy Review* 1995, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections**: *Annual Energy Outlook* 1997, Tables A8 and A20.

Figure 2. Annual Electricity Sales by Sector, 1970-2015
History: Energy Information Administration, *Annual Energy Review* 1995, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections**: *Annual Energy Outlook* 1997, Table A8.

Figure 3. New Generating Capacity and Retirements, 1990-2015
Annual Energy Outlook 1997, Table A9.

Figure 4. Electricity Generation and Cogeneration Capacity Additions by Fuel Type, 1995-2015
Annual Energy Outlook 1997, Table A9.

Figure 5. Fuel Prices to Electricity Suppliers and Electricity Prices
History: Energy Information Administration, *Annual Energy Review* 1995, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections**: *Annual Energy Outlook* 1997, Tables A3 and A8.

Figure 6. Lower 48 Natural Gas Wellhead Prices, 1970-2015
Annual Energy Outlook 1997, Table A1.

Figure 7. Coal Minemouth Fuel Price Projections, 1995-2015
Annual Energy Outlook 1997, Table A1.

Figure 8. Electricity Fuel Price Projections, 1995-2015
Annual Energy Outlook 1997, Table A8.

Figure 9. Levelized Cost of Electricity, 2000 and 2015
Annual Energy Outlook 1997, National Energy Modeling System, run AEO97B.D100296K.

Figure 10. New Generating Capacity by Fuel Type in Two Cases, 1995-2015
Annual Energy Outlook 1997, Tables A9 and F6.

Figure 11. Unplanned Capacity Additions in Three Cases, 1995-2015
Annual Energy Outlook 1997, Tables A9 and B9.

Figure 12. Operable Nuclear Capacity in Three Cases, 1995-2015
Annual Energy Outlook 1997, Table F5.