THE AGING STOCK OF COAL-FIRED ELECTRIC GENERATING UNITS: UTILIZATION, RETIREMENTS, REPOWERING, ADDITIONS AND ENVIRONMENTAL POLICY IMPLICATIONS

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Abstract

The conventional notions of capital scrappage and replacement used in formulating many environmental regulations are inadequate as can be seen in the increasing reliance of electric utilities on older, more polluting, coal units. The notion of a fixed replacement ratio associated with the New Source Performance Standards (NSPS) in the Clean Air Act (CAA) is not a valid assumption for stationary sources that require a significant investment and have long lifetimes. The replacement ratio and deterioration rate for the capital stock of coal-fired generating units in the U.S. is not fixed, as is demonstrated by the changing age and utilization trends in the industry. Clearly replacement decisions are affected by a multitude of financial and regulatory factors.

A database of all coal-fired generating units in the U.S. over the years 1985 through 1994, obtained from the Department of Energy was studied. It was found that over these 10 years, coal capacity aged on average 0.89 years per year, to an average of 22.6 years old in 1994. Similar trends were found for all coal units and annual generation. Although the stock of capital was found to be aging, it was also found that coal units were, nonetheless, being utilized more intensively. Overall, capacity factors weighted by summer capacity increased by 5.5 percentage points over the ten years, to 62 percent. Interestingly, older units experienced higher increases in utilization than other units. In terms of investment trends, few coal-fired retirements, repowering projects, or capacity additions are planned for the next ten years as utilities and nonutilities show reluctance to assume investment risks.

Environmental regulations and public pressure have increased the cost of constructing new capacity. However, the most important factors have been the changes made by Public Utility Commissions and the more recent regulatory changes resulting in large part from the passage of the Energy Policy Act of 1992, that have caused the risks of investing in capital intensive coal burning units to be shifted onto the generators themselves, and away from ratepayers. This shift in risk has produced a reluctance by both utilities and nonutilities to invest in new capital as long as demand can be met through extending the life and/or increasing the utilization of existing capital. Increased reliance on an aging stock of coal units, however, is likely to have significant environmental implications; therefore both environmental and energy policy makers must consider the effects of regulatory changes on investment decisions in the industry and what impacts those decisions will have on the environment.

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"The glory of friendship is not the outstretched hand, nor the kindly smile, nor the joy of companionship; it is the spiritual inspiration that comes to one when he discovers that someone else believes in him and is willing to trust him with his friendship."

- Ralph Waldo Emerson (1803-1882)

I want to give special attention to the wonderful students in the Technology and Policy Program. I cannot say enough to capture how much I value the friendships I have formed with this most interesting and intellectual collection of individuals.

This thesis is the capstone of a long and rewarding academic experience. It has been highly demanding at times, from the days of third grade book reports to more recent NSF fellowship applications, but never once have my parents stopped believing in me, expecting me to do anything but the very best I can, and be nothing but ethical in all of my endeavors. Because of their lifelong love and trust, I dedicate this work to them.

These last two years at MIT have encompassed some of the most challenging yet enriching experiences of my life. It has been difficult at time, but I must say that it has allowed me to mature both intellectually and emotionally. Although this thesis is symbolic of a portion of my life coming to a close, more difficult, but also more exciting, times still lie ahead. Throughout both the happiness and pain that have filled these two years, in the end it has been Debbie's persistent support, love, and respect that have given me hope for the future. Only greater challenges and joys await us both. Thank you Sweetheart.

"Doubt thou the stars are fire;
Doubt that the sun doth move;
Doubt truth to be a liar;
But never doubt I love."

- William Shakespeare. *Hamlet.*

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Chapter 1 Introduction

Many assumptions are made in the formulation of any policy, especially those related to the long-term efficacy of regulatory mechanisms for environmental or economic policy. One of these assumptions, critical to predicting the effects of a particular policy or regulation, is the determinants of the lifetime and deterioration of physical capital. Capital scrappage and replacement allows for incremental or radical changes in process technologies to be implemented, which can potentially result in more efficient and less polluting production systems.[1] Regulatory mechanisms that attempt to advance the current state of implementable technology by integrating pollution control and pollution prevention into the design of new capital have been called *technology forcing*.[2] It in some cases these regulations specify the type of technological system which must be employed for a particular process or industry. Most often, however, they are technology-based standards that set an emission or effluent limit based upon the performance of a particular technology, yet allow firms to meet those standards with any technological system they choose.[3]

The New Source Performance Standards (NSPS)[4] as part of the Clean Air Act (CAA)[5] are the regulatory tool utilized by the federal government through the Environmental Protection Agency (EPA) to set performance and in some cases design standards on new construction within certain industries. One of the industries affected by the NSPS is the electric power generation industry. New coal, gas, and oil-fired boilers,[6] as part of electric generating units,[7] have been required since the 1970 amendments to the CAA to meet emission limitations for particulate matter (PM_{10})[8], sulfur oxides (SO_x), and nitrogen oxides (NO_x). The NSPS mandate more stringent pollution requirements on new

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[1] This statement assumes that capital embodies technology. Although operation practices can also change through technological advancement, in capital intensive processes such as electricity generation, the efficiency and polluting nature of the process is in large part determined by the design and performance of the physical equipment.

[2] For a detailed discussion of technology forcing environmental regulatory policies as they relate to technological innovation see Ashford, Ayers, and Stone (1985) [4].

[3] Providing, of course, that no other applicable federal, state, or local laws and regulations are being violated.

[4] 42 U.S.C. §7411, CAA §111.

[5] The Clean Air Act was originally passed by Congress in 1963 and has subsequently been amended in 1967, 1970, 1977, and most recently in 1990 as Public Law 101-549. For a summary of the provisions of the Clean Air Act Amendments of 1990 see [57].

[6] A boiler is a device for generating steam for power, processing, or heating purposes. Heat from an external combustion source is transmitted to a fluid contained within the tubes in the boiler shell. [19]

[7] A generating unit is any combination of physically connected generator(s), boilers(s), combustion turbine(s), or other prime mover(s) that are operated together to produce electric power [19].

[8] The technical nomenclature in the CAA refers to particulate matter as PM_{10}, signifying a particle size standard of 10 micrometers for determinations of concentration levels.

capital, in this case new electric generating units, than the State Implementation Plans (SIPs) required by the Act for existing generating units[9].

The long-term policy consequences of regulating new units at a lower level of pollution than existing units are a function in large part of the assumptions made concerning technological advancement and especially the rate of capital replacement. If the turnover rate is short, causing units to be replaced often, then any technological advances that result in less pollution can quickly be dispersed throughout the total capital stock of operating units, thereby raising the industry average. However, if units are only rarely retired, then even though new technologies are available, they will not be embodied in new capital unless the discounted economic savings available by using the new technology outweighs the cost of constructing a new unit.[10] Since polluting firms are able to externalize much of the cost of pollution, this factor cannot be relied upon to bring about pollution reducing technological change. Instead, some type of regulatory mechanism such as the NSPS, is needed which cause some or all of the costs of pollution to be internalized.

1.1 Central Questions

This thesis will examine the issues introduced above as they relate to the utilization and capital replacement of coal-fired generating units. The central questions to be addressed are, therefore, the following:

What are the appropriate assumptions concerning the scrappage and replacement of coal-fired electric generating units as they age? What is the evidence that the total stock of coal-fired generating units in the United States are aging (i.e., minimal replacement and retirement of existing units) while continuing to be intensively utilized as base load generating capacity?

Coal is commonly considered to be the dirtiest of the fossil fuels in terms of air pollutant emissions, yet it is the fuel source that provides the largest percentage of the electricity consumed in the U.S. in large part because it is available and inexpensive relative to other fuels. Therefore, it is appropriate to focus upon generating units which use it as their primary fuel source.[11]

In answering the questions above, evidence will be presented showing that the average stock of coal-fired generating units are both aging and being utilized more intensively. It will also be shown that limited new construction, retirements, and repowering of older coal units are taking place or are

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[9] In other words, units which began operation before dates specified by the regulations promulgated after the 1970, 1977, and 1990 amendments to the CAA.

[10] Pollution is often considered to be an economic externality; therefore, technologies that are inherently less polluting will not be utilized by firms unless regulatory or other incentives are provided, that, in one way or another, result in some portion of the costs of the pollution to be internalized by the polluting firm.

[11] At the end of 1994 there were 1219 coal-fired generating units in the U.S. according to the Department of Energy's (DOE) Energy Information Administration (EIA) [31].

planned to take place in the near future. The importance of the assumptions made concerning the lifetimes and utilization levels of existing coal-fired units for environmental policy goals will also be discussed. These assumptions begin with a notion concerning the expected deterioration rate and ultimate scrappage of older units. The basic assumption in the past has been that the ratio of replacement investment to the capital stock and scrappage to the capital stock were constant. Both assumptions were examined by Bitros and Kelejian in 1973 [8] and then by Cowing and Smith in 1977 [13] on an aggregate level using econometric models of electric utility investment behavior. Their conclusions were that scrappage was not proportional to the quantity of existing capital stock, but was instead dependent upon economic factors.[12] Given that these economic factors are variable and must include the cost of complying with regulations, it can not be assumed that capital has a set lifetime or fixed number of operational hours. Certainly economic factors play a role in a firm's decision to replace or continue operating an existing electric generating unit, and the evidence presented will demonstrate that the deterioration patterns, captured by a firm's utilization of generating capital, in the industry are changing due, in part, to transformations in the regulatory system.

As it relates to environmental policy and the CAA, the assumption that was most likely made when the original NSPS were established was that capital would regularly be replaced, and before long all units would meet the higher standards required by the law for new units. National pollution reduction goals would then have been based upon the assumption of a relatively constant replacement ratio. If this assumption is incorrect, however, then regulatory mechanisms such as the NSPS and SIPs have to be set considering the dynamic nature of the economic variables that influence unit replacement decisions.

In the chapters that follow, it will be shown that coal-fired generating units cannot be treated as having a fixed scrappage ratio by way of presenting evidence on recent trends in the electric power industry. One of these trends has been the increasing age of the aggregate stock of coal-fired generating units caused by the few retirements, additions, or repowering projects that have been undertaken. Regulatory changes are affecting the marketplace such that the risk of capital investments is being shifted onto generators, when before it was mostly born by the ratepayers.

1.2 Outline of Approach

This thesis is arranged into six chapters. The remainder of Chapter 1 will provide a brief review of the electric power industry as it relates to the central questions above. Chapter 2 addresses

[12] In their papers, they concluded that replacement investment, as a derivative of scrappage ratio to capital stock, was related to gross investment, maintenance, and the investment rate.

the environmental policy and regulatory factors that are influencing the trend of low replacement rates for coal-fired generating units. It will also describe environmental problems that are potentially aggravated by burning coal for electricity using deteriorating capital. Literature on the economics of capital scrappage and the performance of the electric generating equipment will be reviewed in Chapter 3. The presentation of quantitative evidence to support the claims made above will be done in Chapter 4. This evidence will include data on the aging of the aggregate stock of coal units, changing utilization trends, past and planned retirements, plans for unit repowering, in addition to past and planned unit additions. Final conclusions will then be presented in Chapter 5. A discussion of some of the more detailed issues involved in the analysis of data is given in the Appendix.

1.3 Background on Electric Power Industry

As mentioned above, coal-fired generation is the largest source of electrical energy in the U.S., generating over half the total, but still comprising only 43% of the total 702,658 megawatts (MW) of utility summer generating capacity, or 301,098 MW as of year-end 1994 [19]. The other major U.S. electric utility energy sources in 1994 by generating capacity were natural gas (19%), Nuclear (14%), hydroelectric (14%), and petroleum (10%) [19]. Despite its dominance, though, coal is not relied upon as a fuel source by electric utilities proportionally across regions (see Figure 1).

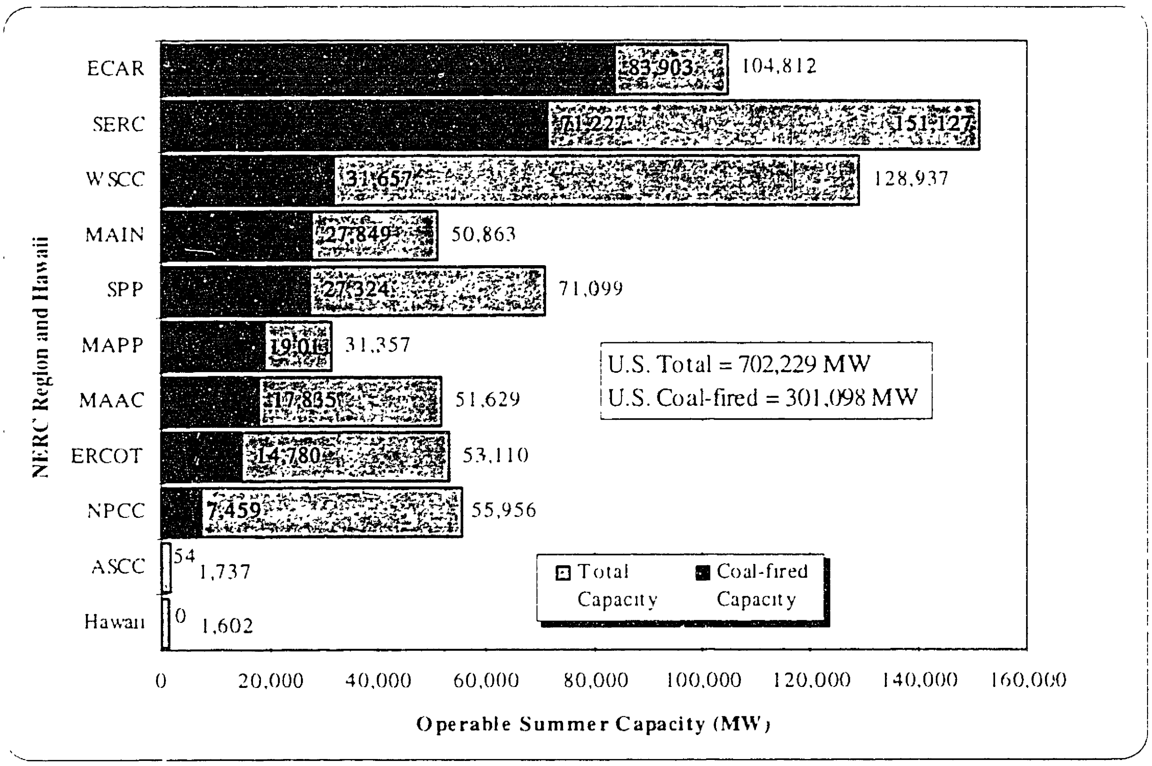

Figure 1: Operable Summer Capacity at U.S. Electric Utilities at the End of 1994[13]

The regions listed in Figure 1 are defined by the North American Electric Reliability Council (NERC);[14] Table 1, below, provides the names of the 10 NERC regions in the U.S. All values listed for the MAPP, NPCC, and WSCC regions are for the portions of those regions within the U.S. only.[15] Hawaii does not belong to a NERC region. As can be seen in Figure 1, much of the coal capacity is concentrated in the coal producing East Central region (ECAR: consisting mainly of the states Kentucky, Indiana, Ohio, West Virginia, Michigan, Virginia, and Pennsylvania) and the Southeastern region (SERC: mainly Florida, Alabama, Georgia, South Carolina, North Carolina, Mississippi, and Tennessee). Coal is relied upon less in the ERCOT region (Texas) where natural gas is used extensively, and in the NPCC region (New England) where petroleum and nuclear power constitute a larger percentage of the available generating capacity.

[13] Source. DOE/EIA-0095(94), "Inventory of Power Plants in the United States 1994," [31]

[14] NERC was established in 1968 and is responsible for setting and maintaining principles, criteria, standards, and guides for planning and operating bulk power systems [49]

[15] Some generating units in Canada and Mexico are also included in these three NERC regions.

Table 1: NERC Council Regions for the Contiguous United States and Alaska

North American Electric Reliability Council (NERC) Regional Electric Council Areas:	
ECAR	East Central Area Reliability Coordination Agreement
MAIN	Mid-American Interpool Network
MAAC	Mid-Atlantic Area Council
MAPP (U.S.)	Mid-Continent Area Power Pool
NPCC (U.S.)	Northeast Power coordinating Council
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
ERCOT	Electric Reliability Council of Texas
WSCC (U.S.)	Western Systems Coordinating Council
ASCC	Alaska Systems Coordinating Council

In terms of actual generation, the total quantity of electricity produced in the U.S. has been growing since the end of World War II, as is shown in Figure 2. Correspondingly, the quantity of electricity generated from coal-fired units has also grown to maintain a relatively constant percentage between 40 and 60 percent. Coal provided 55% of the 2,992 billion kilowatthours of electricity generated in 1995 by utilities in the U.S. Nonutility generators supplied an additional 372.5 billion kilowatthours in 1995.[16] [52] The other energy sources employed by electric utilities in 1994 for net generation were nuclear (22%), natural gas (10%), hydroelectric (8%), and petroleum (3%) [19]. Figure 2 also gives two year projections by the DOE for 1996-1997, showing moderate growth in each category.

[16] Nonutility generators used coal as part of their 314 billion kilowatthours of net generation in 1993, although it comprised only 16% of that generation [3]. See section *4.6 Unit Additions* for a discussion of the growing trend of nonutility generation in the U.S.

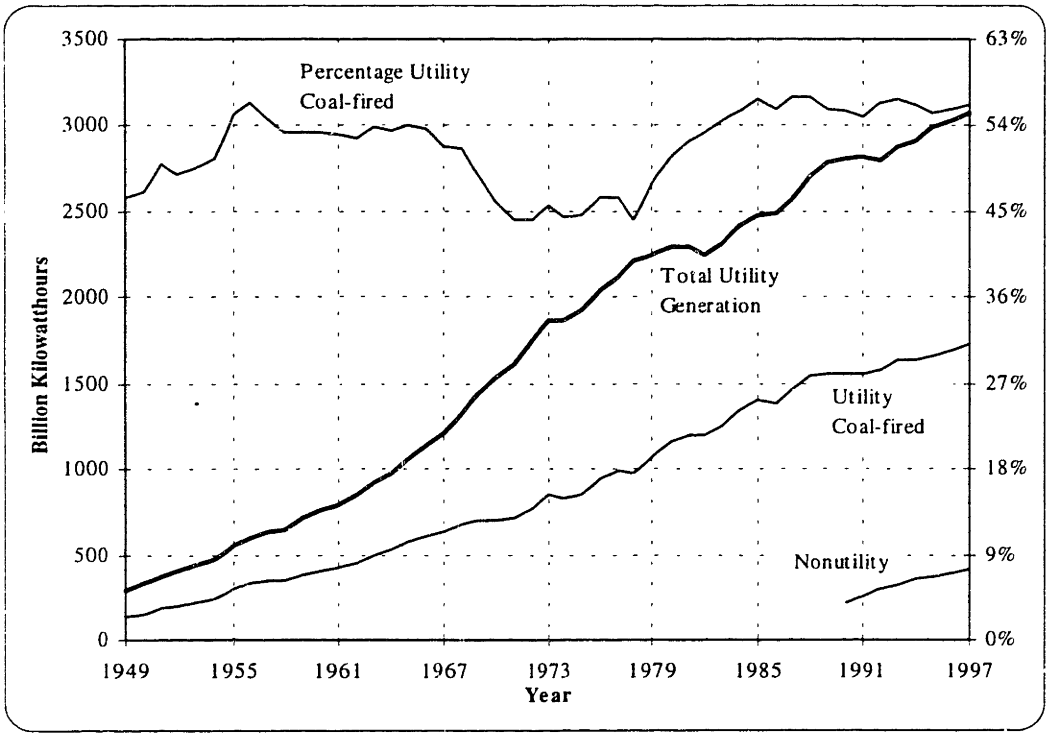

Figure 2: Annual U.S. Electricity Generation by Electric Utilities and Nonutilities with Percentage of Utility Coal-fired Generation (1996 and 1997 values are projections)[17]

1.3.1 Technology

The technology for burning coal and converting the heat energy released into electricity is done by way of a steam-turbine. It has been used in central generating station configurations since the early 1900's and provides the bulk of the electricity generated in the U.S. [36].[18] Other prime mover technologies in addition to steam-turbine generating units are gas turbine units, internal combustion engines, hydroelectric units, and renewable energy units.[19]

Generating units are also classified by their intended application for meeting electricity demand. Baseload units are run at a relatively constant level and are used to satisfy the continuous portion the demand for electricity that does not change over the short-run (day, week, etc.). Peakload

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[17] Sources: 1949-1977 Federal Power Commission, Form FPC-4, "Monthly Power Plant Report." 1977-1981 Federal Energy Regulatory Commission, Form FPC-4, "Monthly Power Plant Report." 1981-1995 Energy Information Administration (EIA), "Monthly Energy Review," DOE/EIA-0035(95/12); Electric Power Monthly, DOE/EIA-0226(95/11). 1996-1997 projections EIA, Short-Term Integrated Forecasting System database.

[18] 62.8% of the electricity generated in the U.S. by electric utilities in 1994 used conventional steam as a prime mover [31].

[19] Renewable energy sources generally include wind, solar, biomass, and geothermal.

units are used to meet load[20] requirements when demand is highest, and generally have a much higher operating cost than baseload units. Gas turbines fueled by natural gas are often used as peaking units because of their higher fuel cost, but lower capital investment. Intermediate-load units are used to meet system requirements when demand is less than peakload, but greater than baseload. Some units are also held in reserve or are not available to the system at various times for maintenance or other reasons. Coal steam-turbine units generally serve as baseload capacity[21] because of their low operating cost. Figure 3 shows the total number of generating units and the number of coal-fired units in each NERC region at the end of 1994. In addition to being operated more often, baseload units also tend to have larger capacities than intermediate or peaking units, thereby allowing few units to meet a large percentage of the region's load.

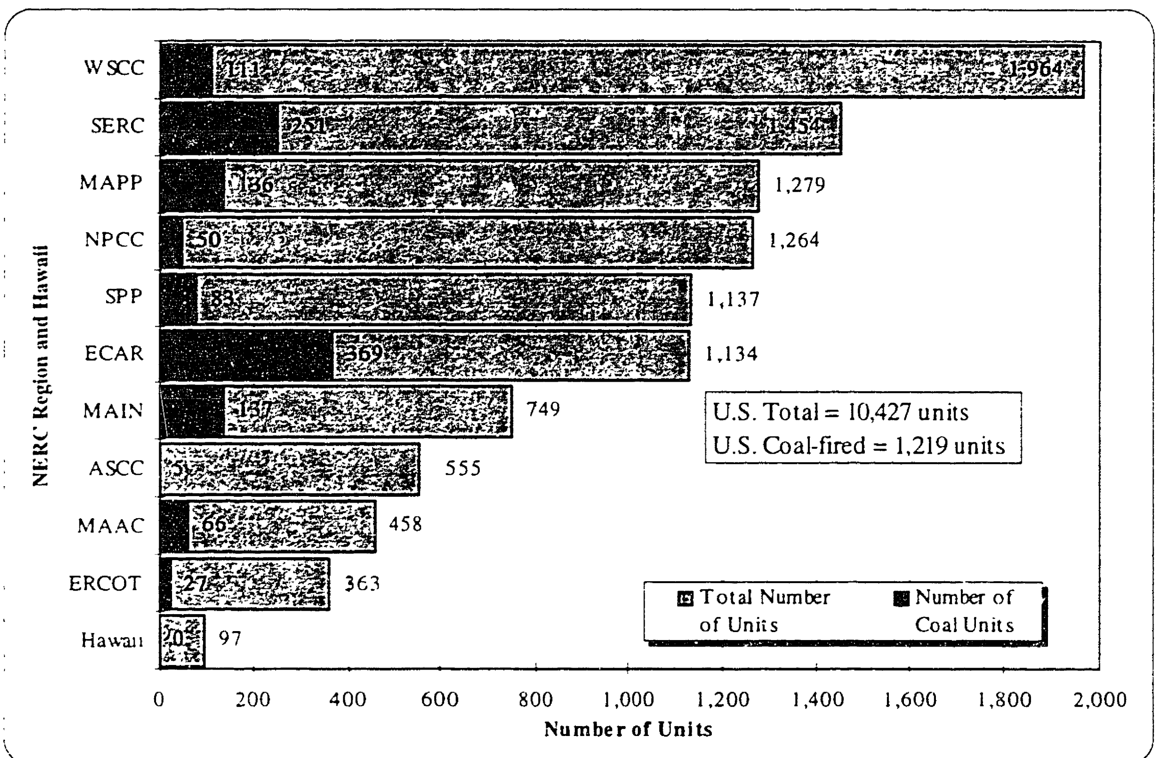

Figure 3: Operable Generating Units at U.S. Electric Utilities at End of 1994[22]

[20] The load is the amount of electrical power delivered or required at any specific point or points on a system and originates from the energy consuming equipment of the end consumers [19].

[21] Baseload capacity includes the generating equipment that normally operates to serve loads on an around-the-clock basis [19].

[22] Source: DOE/EIA-0095(94), "Inventory of Power Plants in the United States 1994," [31].

The thermal efficiency of steam-turbines increased steadily up until about 1965 and since then has improved little [35]. The efficiency of the steam cycle increases with temperature and pressure of the steam, the thermal efficiency of the boiler, the efficiency of the turbine, and the size of the turbine and boilers [56]. This later property in addition to economies of scale in construction costs has led to a historical trend towards the construction of larger and larger units. Beyond a certain size, though, it has been found that units become so large that they are difficult to start-up, shut-down, and maintain, and thereby create reliability problems. Since the mid 1970's the average nameplate capacity of new utility-owned coal-fired units has been around 500 MW [56].

1.3.2 Fuels

Electric utilities used 87% of the 955 million short tons that made up the net domestic supply of coal[23] in 1995 (see Figure 4) [52].[24] Electric utilities, as a group, are the dominant consumer of coal in the U.S. The quality and characteristics of coal mined in the U.S. is, consequently, of great interest to electric utilities. Increasingly, utilities are becoming more concerned about the type of coal they burn, as environmental regulations have become increasingly strict and boiler technologies more refined. In general, however, the fuel source choices made by utilities are mostly determined by availability, price, and the requirements of existing capital equipment.

[23] Coal is a solid combustible substance formed by the partial decomposition of vegetable matter without access to air. The rank of coal, which includes anthracite, bituminous coal, subbituminous coal, and lignite, is based upon fixed carbon, volatile matter, and heating value. [19]

[24] The U.S. is second in domestic coal production after China. The U.S. is also a net exporter of coal, and produced 1034 million short tons in 1995 [52]

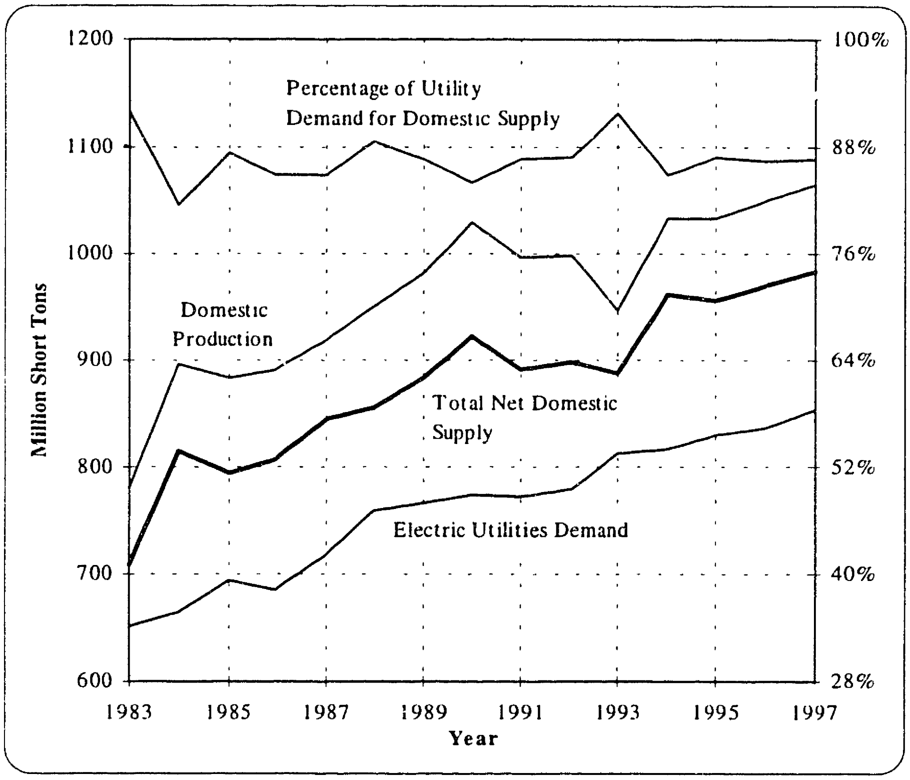

Figure 4: Annual U.S. Coal Supply and Demand with Percentage of Electric Utility Demand for Domestic Supply (1996 and 1997 values are projections)[25]

1.3.3 Economics

The cost of the internal generation of electrical energy is the largest operating expense for investor-owned utilities.[26] Powerplant capital also constitutes the largest portion of the gross investment made by electric utilities [17]. Of the operating expenses at the major investor-owned electric utilities, fuel costs accounted for 77% in 1991, with maintenance (13%) and operation (10%) making up the rest [17]. In terms of ownership, most of the electricity sold to consumers in 1994 was produced by investor owned utilities (76%). Publicly owned (14%), cooperatives (8%), and federally owned utilities (2%) constituted the remainder [20]. Nonutility power producers,[27] as mentioned above, have begun generating an increasing amount of the electricity consumed in the U.S., following

[25] Sources: "Short-Term Energy Outlook, Quarterly Projections, First Quarter 1996," DOE/EIA-0202(96/1Q) [52]. 1996 and 1997 values are projections generated by the DOE Short-Term Integrated Forecasting System.

[26] A utility is a corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the U.S.,.its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for the use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141 [19].

[27] A nonutility power producer is a corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. They are without a designated franchised service area, and do not file forms required from utilities.

the passage of the Public Utility Regulatory Policies Act (PURPA) in 1978. However, they are still responsible for a relatively small portion of total generation.[28]

Overall, the electric utility sector is one of the most capital intensive businesses in the country. In 1993, the utility assets totaled approximately $750 billion dollars, with aggregate operating revenues of about $200 billion [22].

1.3.4 Historical Trends

In addition to slowing improvements in generating efficiency, demand growth for electricity began slowing in the 1970's, from what had previously been an average annual rate of about 8 percent between 1949 and 1973, to an average annual growth rate of 2.6 percent between 1974 and 1989. The average through the 1990's has been slightly above 1 percent and is expected to continue at that rate through the year 2003 [49][29]. In addition to lower growth rates, the aggregate U.S. capacity margin (including both utilities and nonutilities) declined from 33 percent in 1983 to 21 percent in 1993. This drop in margin occurred following the 1970's when electric utilities over-built and ended up with significant overcapacity. Capacity margins are expected to continue to decline to 17 percent by 2003 as utilities and nonutilities face increasing competition [49]. The trends of decreasing demand growth and decreasing capacity margins during the 1990's have led to a situation where little construction of new capacity is taking place.

As was shown above, coal has been the dominant energy source for the generation of electricity during the last half of this century. Since the 1970's, the quantity of electricity generated from the other major fuel sources has not changed significantly. The two exceptions have been petroleum, which has declined in usage, and nuclear, which in the 1970 provided 1.4 percent of the country's utility electricity, and now provides 22 percent (1995) [52]. Little further growth the quantity of electricity generated from nuclear sources is expected in the future, however, essentially because no new plants are scheduled to be built and the existing plants already operate at high capacity factors [56].[30] Hydroelectric power has been limited by the number of economically feasible sites; few, if any, large projects are expected to be undertaken in the near future. In contrast, because coal is the least expensive of the fossil fuels per unit energy yield [56], may increase its dominance of the U.S. power generation market, depending upon the economics of new natural gas baseload capacity how long the existing stock of nuclear powerplants are kept in operation [1]. As for nonutility generators, natural

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[28] See section *4.6 Unit Additions* for a more detailed discussion on the role of nonutility power producers in the electric power industry.

[29] Demand growth in 1994 and 1995 was 1.0 and 2.8 percent, respectively [52].

[30] In 1994, the average capacity factor for nuclear steam plants as reported to NERC was over 73% [27].

gas has been the fuel of choice, supplying 54 percent (176 billion kilowatthours) of their needs in 1993 [3].

Chapter 2 Regulation and Environmental Policy

The conversion of energy from one form to another can never be one-hundred percent efficient, and consequently will always have some environmental impacts. This conversion process when executed on a large scale, such as when electricity is generated, has become a critical input for industrialized economies. Because of its role in society and inherent economies of scale, it has been, and probably always will be, the focus of special regulatory attention. The regulatory consideration given to electric utility and nonutility generators, consequently, has been justified on both economic and environmental grounds. Once implemented, though, the effects of a particular regulatory design are necessarily uncertain, and so predictions must be made which are based upon particular assumptions. Once again, the concern here is the assumptions made addressing the replacement of electricity generating equipment that is in question. More specifically, under investigation is whether the assumption of a fixed replacement ratio is an acceptable approximation. Before presenting detailed evidence that supports an alternative hypothesis, that the replacement ratio is not fixed for coal-fired generating units, a discussion of the regulatory system in which economic decisions are made is pertinent. Proceeding even that discussion, however, the nature of the environmental concerns over using coal to produce large quantities of electricity will be addressed.

2.1 Environmental Policy Issues

Although there are many environmental issues associated with the generation of electricity, including land usage, resource extraction and reclamation, and solid waste management, the issues which have garnered the most attention have been more directly associated with the combustion of fossil fuels.[31] Emissions from electric power generation are the result of both complete and incomplete combustion. Complete combustion produces carbon dioxide (CO_2) and water vapor, while incomplete combustion yields unburned fuel, particulate matter (PM_{10}),[32] and carbon monoxide (CO). Additional pollutants include nitrogen oxides (NO_x) which form at high temperatures when nitrogen in the air and in the fuel combine with atmospheric oxygen, and sulfur dioxide (SO_2) which is formed through the oxidation of sulfur present in varying amounts in fossil fuels, and some other trace pollutants including

[31] A great deal of attention has also been given to the issues involved with the use of nuclear fission for the generation of electricity. The result has been that nuclear reactors have been put under strict environmental and safety regulations. In terms of cumulative impacts on the environment, however, fossil fuels, and especially coal, have probably had a much larger impact. Fossil fuels are used to generate nearly 70% of the electricity consumed in the U.S. [22].

[32] Measured as the quantity of particulate matter with diameters less than 10 microns.

some heavy metals. Nearly all coals contain some sulfur, ranging from trace amounts to six percent by weight [11].[33] Coal-fired generating units produce more SO_2 than units using other fuels because coal generally contains higher concentrations of sulfur. Likewise, because more coal is burned for electricity than any other fuel, coal units also produce more NO_x emissions [20]. Figure 5 below shows that electric utilities are responsible for a large portion of the U.S.'s emissions of CO_2, SO_2, NO_x, and nitrous oxide (N_2O).

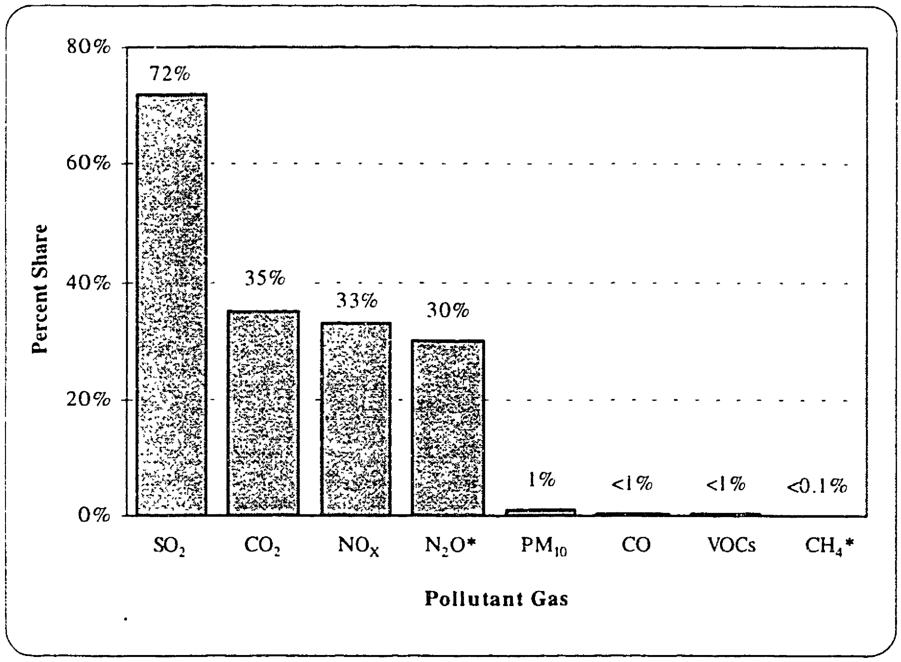

Figure 5: Electric Utilities' Share of Total U.S. Emissions of Eight Air Pollutants, 1993[34]
(* 1992 Data)

Of the nitrogen oxides produced by coal units, nitrogen dioxide (NO_2) is the one that contributes the most to urban ozone problem and gives smog its characteristic yellow-brown hue [20]. These chemicals, along with volatile organic compounds (VOCs), react with sunlight to form the low

[33] The choice of coal types is mostly an economic decision, although sulfur content is also a relevant factor. The proximity of the coal source and mining costs are the most important factors. Coal mined in the western states of the U.S., especially the Powder River Basin of Wyoming, on average tends to have lower sulfur content than coal mined in the eastern of the Mississippi River, although some southern Appalachian coal is considered low sulfur. More than half of the coal mined in the western states is subbituminous low sulfur coal (about 0.5% by weight) and provides approximately 9,000 Btu per pound or less. Some bituminous eastern coal can exceed both a 5% sulfur content and 12,000 Btu per pound heat content.

[34] Source: "Environmental Externalities in Electric Power Markets: Acid Rain, Urban Ozone, and Climate Change," DOE/EIA-0603(95). [11]

level ozone which has become a significant health threat in many urban areas during the summer months [11].

Acid rain[35] is to a large part the result of increased atmospheric concentrations of SO_2 and NO_x that react to form sulfuric and nitric acids. These acid droplets cling to all forms of precipitation or can fall to the ground as dry deposition either of which causes ecological, health, and property damage. The most severe conditions of acidification have occurred in the eastern portion of the U.S. where the aquatic life in many streams and lakes have been severely damaged or eliminated [11]. As mentioned above, coal-fired generating units contribute the bulk of the SO_2 and NO_x emitted by electric utilities. Emissions of SO_2 by coal units were 11.42 MMT[36] or 96 percent of utility emissions in 1994. Likewise, coal unit emissions of NO_x were 4.67 MMT or 90 percent of utility emissions during the same year [20]. Figure 6 shows total U.S. electric utility emissions of SO_2 and NO_x back to 1987.[37]

[35] Unpolluted rainfall is normally slightly acidic (pH $\approx$ 5.6); acid rain is conventionally defined as any precipitation with a pH of 5.5 or less [11].

[36] MMT - Million Metric Tons

[37] Historical data before 1987 showing emissions of SO_2 and NO_x for coal-fired units were not available due to revised estimating methods by DOE's Energy Information Agency beginning in 1993 which caused earlier estimates to be inconsistent with current ones.

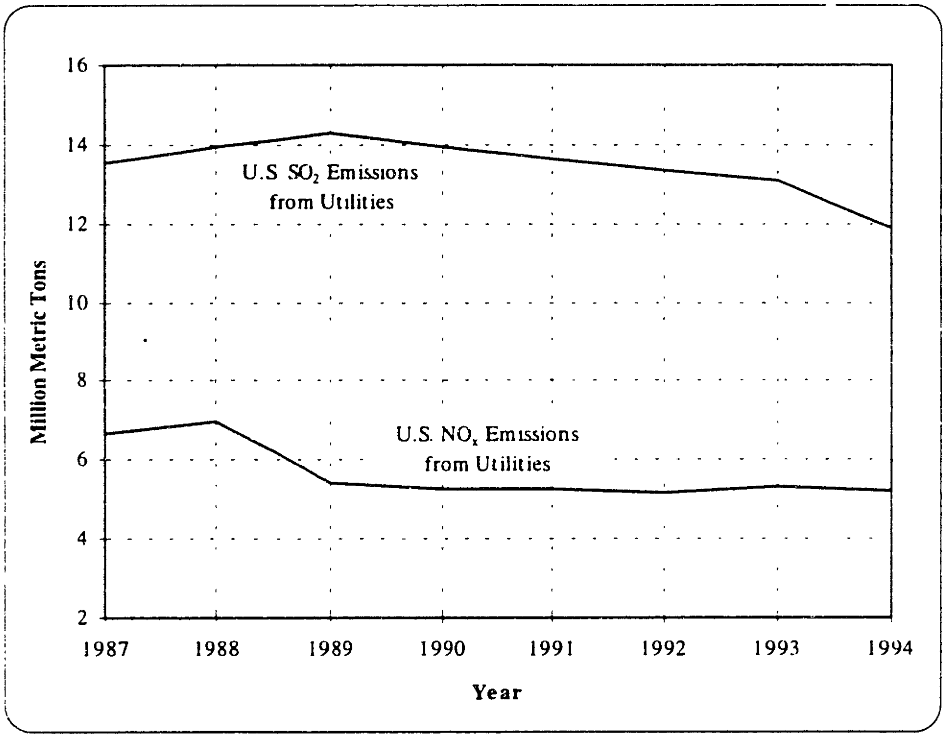

Figure 6: U.S. SO_2 and NO_x Emissions from Fossil-Fueled Electric Utilities[38]

U.S. carbon dioxide emissions are mostly accounted for by the combustion of fossil fuels such as coal, oil and natural gas (98.5 percent in 1992).[39] Although CO_2 is a colorless, odorless, nontoxic gas, its buildup in the atmosphere has caused a great deal of concern due to its potential effects upon the global climate system. CO_2 along with methane (CH_4), N_2O, and chlorofluorocarbons (CFCs) are the principle gases deemed responsible for the anthropogenic contributions to the greenhouse effect.[40] Emissions of CO_2 are not regulated; however, they are the focus of several international agreements, including the Framework Convention on Climate Change (FCCC) through the United Nations. In response to the ongoing FCCC, the U.S. has developed a Climate Change Action Plan and committed itself to stabilize greenhouse gas emissions at the 1990 level by the year 2000.[41] Electric utility

[38] Source: 1990-1994 SO_2 and NO_x utility emissions are from *Electric Power Annual 1994: Volume II*, DOE/EIA-0348(94)/II [20]. 1987-1989 SO_2 and NO_x utility emissions are from *Electric Power Annual 1993*, DOE/EIA-0348(93) [18].

[39] Source: *Emissions of Greenhouse Gases in the United States 1987-1992*, DOE/EIA-0573 [23].

[40] The term climate change is probably more suitable than greenhouse effect, because the most likely consequences of the effect will be more along the lines of changes in regional climate patterns and not simply an increase in the global average temperature. Some regions may show a decrease in average temperature or precipitation, while others may see an increase. The United Nations Intergovernmental Panel on Climate Change (IPCC) estimates that CO_2 is globally responsible for 55% of the radiative forcing climate change effects. For a more detailed review of greenhouse gas contributions see *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1993*, EPA 230-R-94-014 [32].

[41] It has become fairly clear, however, that the U.S. will not reach this goal.

emissions are a significant component of U.S. total CO_2 emissions, making up approximately 33 percent (1993) [23,20]. Of the amount produced by utilities, 88 percent (1519.5 MMT) was from coal-fired units in 1994 [20]. Clearly, coal-fired generating units play a significant role in the U.S.'s contribution to rising global atmospheric CO_2 concentrations (see Figure 7).[42] Similarly, as was mentioned above, coal generating units are major emitters of SO_2 and NO_x and consequently are a major contributor to the environmental impacts that result. Any comprehensive environmental policy that attempts to lead to the reduction in the emission of these gases must seriously consider both the technological options and economics underlying the generation of electricity from coal.

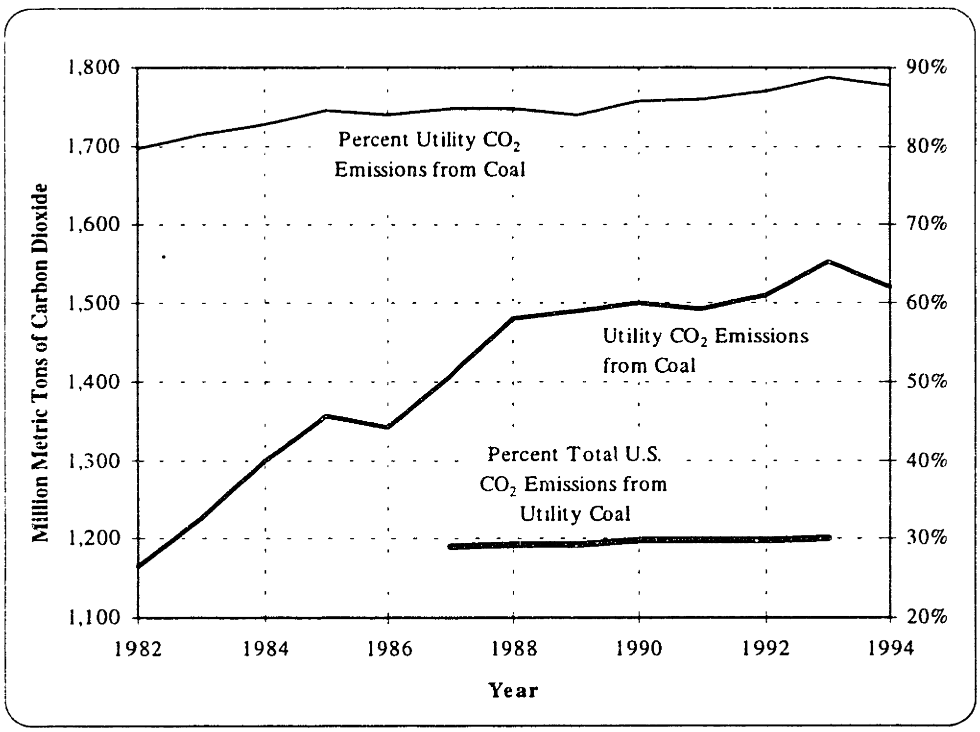

Figure 7: U.S. Carbon Dioxide Emissions from Coal Burned at Electric Utilities with Overall Utility and Nation-wide Percentages[43]

Although the simplest way to reduce the negative environmental impacts from burning coal would be to reduce consumption, also at issue is the technology used for the coal that is burned. There

[42] The concentration of CO_2 in the atmosphere has increased 27% from preindustrial levels according to the IPCC.

[43] Source: Total U.S. emissions are from *Emissions of Greenhouse Gases in the United States 1987-1992*, DOE/EIA-0573 [23]. 1982-1992 utility emissions from coal and overall utility emissions are from *Emissions of Greenhouse Gases in the United States 1987-1992*, DOE/EIA-0573 [23]. 1993-1994 emissions from utilities and 1994 utility emissions from coal are from *Electric Power Annual 1994: Volume II*, DOE/EIA-0348(94)/2 [20]. 1993 utility emissions from coal was taken from *Electric Power Annual 1993*, DOE/EIA-0348(93) [18].

are many technological strategies available to reduce pollutant emissions from coal-fired units. Before the 1970's and the first Clean Air Act Amendments (CAAA), however, one of the preferred pollution control strategies was simply to build towering smoke stacks in hope that the wind would disperse and carry the pollutants away from populated areas [59]. Since then, better pollution control and pollution prevention technologies have come into use.

SO_2 emissions can be reduced using several different methods, including switching to a coal with a lower sulfur content, coal washing, and scrubbing coal emission with flue gas desulfurization (FGD) systems.[44] Recently, the two options that have been employed the most by utilities have been switching to low sulfur coal and scrubbing [20]. Figure 8, below, provides numbers on the growing use of scrubbers by utility generating units. In contrast, nitrogen oxide emissions, unlike SO_2, are not as dependent on the type or quality of the fuel burned as they are on the combustion process itself. The temperature of the combustion chamber is the controlling variable and several methods are available to reduce emissions including: lower combustion temperatures, low nitrogen containing fuels (such as natural gas), staged combustion processes that limit NO_x formation, low NO_x burners, and fluidized-bed combustion (FBC) [20]. The most important factor in influencing the use of such technologies or strategies is environmental regulation, and specifically the CAAA.[45]

[44] FGD's, or scrubbers, use chemical agents such as lime to remove sulfur oxides from the combustion gases of boilers before the gases are released to the atmosphere [20].

[45] See section *2.2.1 The Clean Air Act Amendments*

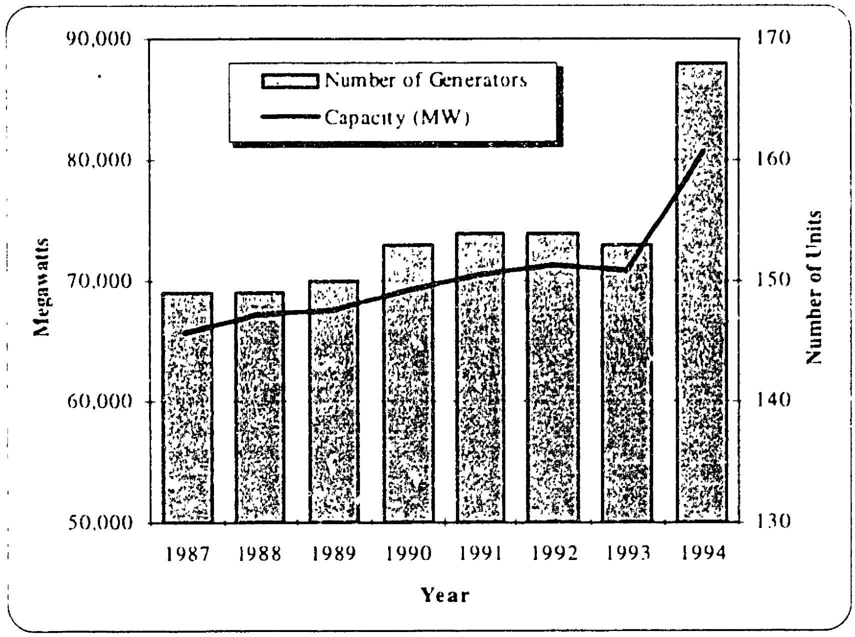

Figure 8: Number and Capacity of U.S. Utility Fossil-Fueled Generators with Scrubbers[46]

As for CO_2 emissions, there are few practical control strategies that exist. Tail gas cleanup (CO_2 scrubbing) technologies could potentially be adapted from the petroleum refining industry, but would be extremely expensive [20]. The main option currently foreseen is to improve the efficiency of the energy conversion process, thereby allowing less fuel to be burned. Clean coal technologies such as FBC, pressurized fluidized-bed combustion (PFBC), and integrated gas combined-cycle (IGCC)[47] units burning coal gas not only operate with higher efficiencies, thereby reducing CO_2 emissions, but also greatly reduces SO_2 and NO_x emissions [46,30]. Older existing units can also be rebuilt, called "repowering", to use these or other more efficient technologies without requiring the construction of an entirely new facility.[48]

Despite the availability of these technologies, however, coal units using older technology are continuing to be utilized and few are being replaced. This trend is obviously influenced by how the industry is regulated, but also because these technologies are simply still more expensive, given current fuel prices, than basic coal-fired steam systems. If one of our environmental policy goals is to encourage the use of inherently less polluting technologies or fuel sources in the generation of

[46] Source: 1990-1994 values are from *Electric Power Annual: Volume II*, DOE/EIA-0348(94)/2 [20]. 1987-1989 values are from *Electric Power Annual 1993* (and earlier), DOE/EIA-0348 [18].

[47] Combined cycle is a generating technology in which electricity is produced from otherwise lost heat exiting from one or more gas turbines. The exiting hot gases are routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine, thereby increasing the overall efficiency of the generating unit. [19]

[48] See section *4.5 Repowering* and *4.6 Units Additions*.

electricity, then we must integrate the factors that effect capital scrappage and replacement decisions into the formulation of those regulations by internalizing some of the costs of pollution, thereby making less polluting energy sources more cost competitive.

2.2 Regulatory Issues

Essentially all grid connected electric generators are subject to a multitude of regulatory constraints and oversight. Multiple state and federal regulations have been created because of the central role of electrical energy in the U.S. economy, its natural monopolistic characteristics, and its impacts on the environment. Coal-fired generating units have been the focus of many of the regulations directed at electric utilities because of their dominant contribution to the national energy mix for electricity and their more polluting nature compared to other fossil fuels. State commissions have regulated utility electric rates and investment decisions for some time, and the federal government has taken the role of regulating wholesale transactions[49] of electricity across state lines. As for environmental regulation, the major piece of legislation impacting electric utilities has been the CAA, in which limitations and requirements on coal burning units have become increasingly rigorous, and consequently have raised the cost of producing electricity from coal. The continued low price of coal relative to other fuels along with the sunk cost of existing coal burning plant capital has allowed it to maintain its dominance despite the additional costs imposed by the CAA.

Over time, many of these regulations have increased in scope and stringency, with one of the results being that the real cost of constructing new plants has increased. Additional costs have been imposed by the Not-In-My-Backyard (NIMBY) phenomenon found in many local communities; these local activists have often made siting new plants in proximity to the people they serve more difficult. In combination with mounting regulatory constraints and costs, utilities are now also facing an increasingly uncertain marketplace. As discussed above, the demand for electricity has fallen from its historically rapid growth rate. Prior to the 1970's, nearly every utility could assume that any new generating unit it built would be needed sooner or later, yet now utilities face a marketplace where that older assumption is no longer valid. Planning for new capacity must be done carefully, weighing the costs of excess capacity, which before had been borne by the consumer but now is increasingly laid upon generators, versus the costs of more system maintenance and potential load interruptions. The most important factor producing this shift in the risk on to generators has been, and will continue to be, the deregulation of the electric power industry, which first began with the passage of the Public Utility

[49] Wholesale transactions involve energy supplied to other electric utilities, cooperatives, municipals, and federal and state electric agencies for resale to ultimate consumers [19].

Regulatory Policies Act (PURPA) in 1978,[50] and continued with the passage of the Energy Policy Act (EPACT) of 1992.[51] Both of these legislative acts have enlarged the role of nonutility generators, and placed more competitive demands on utilities.

In summary, electric utilities that in the past were guaranteed both a monopoly in their market and a fair, if not better than fair, return on their investment have, more recently, been faced with a situation of slowing growth in demand, intensifying regulatory pressures, and increasing uncertainty. All of these factors have an economic impact, and therefore influence a utility's decisions concerning investment in and utilization of existing and new coal-fired generating units.

2.2.1 The Clean Air Act Amendments

The regulation of air quality in the U.S. at the federal level began with simple measures to research the problem[52] and help state governments develop their own pollution control agencies.[53] The federal government began claiming a more prominent role in air quality regulation, though, with the passage of the Air Quality Act of 1967, in which criteria were set for states to adopt ambient air quality standards [21]. The piece of legislation that truly marked Washington's central position in air quality regulation, however, was the Clean Air Act Amendments (CAAA) of 1970.[54] Each subsequent revision of the CAA, in 1977 and most recently in 1990, has mandated regulations that are designed to become more stringent over time [11].

2.2.1.1 Ambient Air Quality Standards

In the 1970 amendments, Congress decided that National Ambient Air Quality Standards (NAAQS) would be set for pollutants dangerous to public health, termed criteria pollutants. The newly formed Environmental Protection Agency (EPA) was responsible for establishing these NAAQS and then states were to develop State Implementation Plans (SIPs) to be approved by the EPA. To date, NAAQS standards have been set for six criteria pollutants: PM_{10}, SO_2, CO, N_2O, lead (Pb), and ozone (O_3). For monitoring purposes, the country was divided into air quality control regions that were then classified as being in "attainment" or as "nonattainment areas" for each of the criteria pollutants. New

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[50] Public Law 95-617.

[51] Public Law 102-486.

[52] An Act to Provide Research and Technical Assistance Relating to Air Pollution Control was passed in 1955 to provide funds for research into the growing problem of urban air quality [21].

[53] The Clean Air Act of 1963 expanded the role of the federal government, claiming a role in interstate negotiations and funding state air quality agencies [21]. It became the foundation of the subsequent CAAA and the Act as it is currently know.

[54] It should be noted that although through the CAAA, the federal government has taken a leading role in air quality regulation, Congress has been careful in each of its revisions to acknowledge the primary responsibility and rights of the individual states to control air pollution. Consequently, much of the Act is administered through state and local agencies.

sources in nonattainment areas were, and still are, required to attain the "lowest achievable emission reduction" (LAER)[55] as defined by EPA [21]. The 1977 amendments then developed more detailed requirements for attainment and nonattainment areas. In attainment areas, sources were required to use the "best available control technology" (BACT)[56] and regions were classified further to "prevent significant deterioration" (PSD) of air quality in more pristine areas. In nonattainment regions, existing sources were regulated to use "reasonably available pollution control technologies" (RACT).[57] [21] In addition to meeting LAER, new sources in nonattainment areas are required to offset their emissions by purchasing and closing down older sources or pay other sources to reduce their emissions by an amount greater than the amount added by the new source [9].[58] These provisions have remained essentially intact in the 1990 amendments to the Act.

2.2.1.2 New Source Performance Standards

In addition to the restrictions placed on existing and new sources, the 1970 amendments also established federal New Source Performance Standards (NSPS). The standards mandated by Congress were to be based upon the "best system of emission reduction which...has been adequately demonstrated."[59] [21] In 1971 EPA promulgated its regulations for five industrial categories, including fossil fuel-fired steam generators [58]. In the regulations, coal-fired utility boilers built after August 17, 1971, were required to emit no more than 1.2 pounds of SO_2 per million Btu[60] of heat input. Particulate matter and a complex set of NO_x standards were also established by EPA for new sources. The NO_x standards limited emissions to 0.2 to 0.8 pounds per million Btu, depending upon the type of coal burned and combustion system employed. [20]

In 1979, after passage of the 1977 amendments, EPA issued its Revised New Source Performance Standards (RNSPS) [20]. The RNSPS retained the original 1971 NSPS requirements, but added more stringent standards for new construction or modification initiated after September 12, 1978 [21]. Coal units constructed after this data were required to reduce their SO_2 emissions at least 90 percent unless that level of removal would reduce their emissions below 0.6 pounds per million Btu. If emissions were to fall below that level, then reductions between 70 and 90 percent were permitted,

[55] LAER technology-based standards do not permit cost to be considered in the standard setting process [21].
[56] BACT technology-based standards permit some consideration of cost of abatement [21].
[57] RACT technology-based standards take into account both cost and technological feasibility [21].
[58] This system of offsetting is termed "netting" by the EPA.
[59] NSPS are to consider the cost of achieving the defined reduction and any non-air quality health and environmental impacts and energy requirements.
[60] Btu = British thermal unit. A Btu is a standard unit for measuring the quantity of heat energy, equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit. [19]

depending upon the sulfur content of the coal burned.[61] [20] The RNSPS for NO_x and particulate matter were also altered by EPA to be more stringent for some categories of boilers and coal types [21]. The RNSPS were retained in the 1990 amendments, and therefore are still in effect today.

The increased attention given to coal burning in 1977 was in part the result of the oil price shocks and Arab oil embargo of the early seventies. In the wake of these events, it became a national policy to rely less on imported oil for electricity generation and more on domestic coal stocks. Environmentalists, however, were fearful that increased usage of coal would lead to worsening air quality and consequently pushed for more stringent emission standards. [14] In this political climate, Congress' language in the 1977 amendments was read by industry and the EPA as requiring that all new coal units would have to employ a technological system to reduce emissions regardless of the quality of fuel burned, and the only system available were flue gas desulfurization systems (scrubbers). In effect, economic efficiency was compromised away in order to reduce the incentives for utilities to utilize eastern or western low sulfur coal exclusively. To the satisfaction of the eastern coal mining firms in high sulfur areas, the advantages of burning low sulfur coal were reduced, and in some cases were eliminated depending upon the cost and availability of coal from low sulfur regions.[62] [14]

The rationale in the CAA for treating new sources more stringently than existing ones was based, in part, on the assumption that older plants had in most cases been constructed with little thought given to pollution control. Retrofitting these plants with would be expensive and incur the wrath of existing political coalitions. New plants, in contrast, could more easily be designed with pollution control systems in mind. [2] Whether or not this assumption was accurate, the PSD rules, NSPS, and RNSPS, by increasing the construction and operating costs of new plants, created an incentive against new construction. Older plants were subject only to SIPs rules, which were almost always less stringent. The de facto requirement to install scrubbers on new units typically added approximately 25 percent to the cost of a new coal-fired powerplant[63] in the 1980's [56]. The result contributed to the slowing rate of capital turnover, and therefore, progress towards national air quality goals. As a consequence other steps were taken in the 1990 amendments to deal specifically with SO_2 emissions.

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[61] Utilities were also required to establish a continuous monitoring program for their SO_2 emissions. The emission limitations were based upon a 24 hour rolling average. [21]

[62] For an analysis of the setting of the NSPS for coal burning and the influence of the coal mining industry, see Ackerman and Hassler (1981) [2] or Crandall (1983) [14]. Although all coal burning units were essentially required to install scrubbers, such systems require larger capital and operating outlays when high sulfur coal is combusted.

[63] A powerplant is a facility containing prime movers, generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electricity [19].

2.2.1.3 Acid Rain Program

Title IV of the CAAA of 1990 established the Acid Rain Program with the primary goal of reducing the annual SO_2 and NO_x emissions from electric utilities by 10 million tons and 2 million tons, respectively, below their 1980 level by the year 2010 [21]. The program is divided into two phases and uses a tradable allowance system to limit total emissions and minimize the costs of the program. Phase I, began on January 1, 1995, and set an SO_2 emission limitation of 2.5 pounds per million Btu on 261, mostly coal-fired, high polluting generating units located in 21 eastern and midwestern states [11].[64] For the 261 units using boiler configurations specified in the regulations, NO_x emission limitations are also established.

Phase II begins on January 1, 2000, and will establish more stringent and broader SO_2 reduction requirements that will apply to essentially all fossil-fueled powerplants. An emission level of 1.2 pounds per million Btu will be set with an additional nationwide cap on total SO_2 emissions at 8.9 million tons annually that will be enforced through the issuance of a fixed number of tradeable emission allowances. [11] New plants will only be able to begin operation after 2000 if they purchase marketable allowances from existing facilities. SO_2 allowances are allocated to affected powerplants for both Phase I and Phase II based upon the emission limits prescribed by each phase.[65] These allowances can be used, sold, or banked. Phase II will also expand the NO_x standards to all generating units.

The major compliance options open to the 261 units affected by Phase I and all the other units affected by Phase II are: (1) fuel switching and/or blending, (2) obtaining additional allowances, (3) installing scrubbers, (4) using previously implemented controls, (5) retiring facilities, and (6) boiler repowering [21]. According to DOE, about 62 percent of the Phase I units plan to comply by switching to low sulfur fuel, 15 percent by purchasing extra allowances from other utilities, and 10 percent by installing scrubbers.[66] [21] Fuel switching has been favored both because of the low cost of low sulfur coal,[67] and because of the lower capital expenditure required [21]. Phase II will require essentially all fossil-fueled plants to choose a compliance option and the original Phase I units will be required to make additional modifications [49]. Nonutility units existing or under development before 1990 will not be required to purchase SO_2 allowances; however, later nonutility units will be required

[64] More than 75% of the generating capability affected by Phase I is located in eight states: Georgia, Illinois, Indiana, Missouri, Ohio, Pennsylvania, Tennessee, and West Virginia [11].

[65] A unit affected by Phase I was allocated allowances equal to its annual average fuel consumption during 1985 through 1987, multiplied by the emission rate of 2.5 pounds per million Btu. During Phase II, allowance allocation will be determined using the same fuel consumption multiplied by 1.2 pounds per million Btu. [11]

[66] Scrubber systems can reduce a generator's output by approximately 2% [49].

[67] Low sulfur coal generally considered to be less than 1.5% sulfur by weight.

to possess allowances after 2000. No allowances will be allocated to nonutilities, and therefore they will have to purchase allowances sufficient to cover their annual emissions. [56]

Utilities and nonutilities also face other future uncertainties beyond how the Phase II emission standards and allowance trading system will effect them. A decision by EPA or Congress to establish more stringent air toxic emission standards, strengthened PSD emission limitations, regulations potentially requiring low NO_x burners, and increasing competition in coal prices between the western and eastern mines all present utilities and nonutilities additional factors which must be considered in planning for future capacity. In general, though, environmental regulations have somewhat increased the overall operating costs of electric utilities, but it has been the shifting of the risks of unwise investments to the generators that has had the most potent effect.

2.2.2 State Regulations

State regulation of electric utilities began almost as soon as wide scale-distribution of electricity began. Both because of the naturally monopolistic characteristics of electricity distribution and the high percentage of utilities that are privately owned,[68] state governments have found that they have a role in ensuring that the public is provided with fair pricing and equitable access. The more typically employed regulatory body has been the Public Utility Commission (PUC), which exist in essentially every state where there are privately owned utilities. Their function is to regulate the retail electricity rates charged by utilities, which has normally been done by allowing rates to be set so that the utility can cover their total operating expenses; including fuel, operations and maintenance, and capital; plus a "fair rate of return"[69] on the capital held by the utility. [56]

Before the 1970's, regulation of utilities was fairly simple. Technological advances and consistently high growth in demand created a market in which the per-unit nominal costs of producing electricity had been falling. This situation made it possible for the PUCs to lower retail electricity rates each year, while also permitting utilities to earn a profitable rate of return. [56] In the 1970's and 1980's, however, the real cost of generating electricity increased dramatically, and consequently, so did electricity rates. Between 1973 and 1982, average retail rates increased in real dollars by over 50 percent [56]. This occurred following a decrease in the real price of electricity by 30 percent between 1960 and 1970 [56].

[68] In 1994, 76% of electric utilities were investor owned; publicly owned, cooperative, and federally owned utilities constituted the remainder [20].

[69] A fair rate of return is normally defined as one equal to other investments with a similar quantity of risk involved, while being high enough to raise the necessary financial capital for new construction [56].

The reasons for this rise in electricity rates were that during the 1970's, utilities were faced with increasing fuel, operation and maintenance, and capital costs. The real cost of coal increased by almost 90 percent between 1973 and 1982, in part due to changing fuel use patterns in the early 1970's and lower mine productivity [56]. During the same period the real cost of natural gas to utilities increased by over 800 percent, partially due to the passage of the Natural Gas Policy Act of 1978, which gradually deregulated natural gas prices [56]. Average operation and maintenance costs increased mainly as a result of unexpectedly high costs at nuclear powerplants.[70] The rise in the cost of new plant and other capital was, in part, the result of rising interest rates, especially on the bonds often used to finance capacity expansions by utilities.[71] Interest payments during the construction of a new baseload powerplant can represent as much as 15 to 20 percent of the real capital investment cost [56]. The end result of these changes was that the construction costs for fossil-fueled powerplants increased from an average of $137 per kilowatt of generating capacity in 1968 through 1971, to $961 per kilowatt in 1987. During the same time period, the implicit price deflator of the gross national product only tripled. [56]

These cost increases caused many utilities to file requests for PUCs to allow them to charge higher rates. Many of these PUCs looked critically upon such requests. During the 1970's investments made by utilities were undertaken with the expectation that demand would continue to grow at its historically high rate. Despite their predictions, however, demand growth slowed considerably and resulted in a situation where many utilities were burdened with excess capacity.[72] Under most state regulatory systems, this excess capacity was not accepted to be the result of prudent investments, and therefore did not meet the "used and useful" criteria employed by many PUCs to determine the portion of the utilities capital stock that can be included in the determination of its allowed rate of return. Straddled with overcapacity, burdened with an overall increasing cost structure, and facing tighter scrutiny of retail rates by PUCs, many utilities began to view capacity additions or replacement investments as being far more risky than they had been in the past. [56]

2.2.3 Deregulation

Probably the most critical issues facing the electric power industry today, however, are associated with deregulation and competition in the marketplace, both of which are leading to

[70] Average maintenance costs at nuclear powerplants increased by over 150% while operation costs rose by over 200% between 1974 and 1982 [56].

[71] The average interest rate on high-grade corporate bonds went from 4.4% in 1961 to 7.4% in 1971, and then to 14.2% in 1985 [56].

[72] Averch-Johnson (1962) [5] discusses how regulatory constraints on rates of return biased firms such as electric utilities to be more capital intensive than they would otherwise be.

substantial changes in the structure and organization of the industry. Utilities are no longer certain that they will be able to recover their capital investment in generating capacity because they can no longer pass the cost of excess capacity on to ratepayers. Likewise, nonutility generators, which had previously been able to obtain long-term contracts with utilities, are now faced with a more open market situation. The overall result has been that the risks of investing in capital within the industry, both for utilities and nonutilities, has been shifted to a greater degree onto the generators.[73] These changes began with the passage of the Public Utility Regulatory Policies Act (PURPA) of 1978[74] which was intended to encourage energy conservation and generation by nonutilities. [49]

A series of events preceded the passage of PURPA. By 1970, electric utilities had nearly become the sole supplier of electricity to U.S. industry. Little in-house generation took place because electricity was both inexpensive and reliable. During the 1970's, however, rates began to increase as technological limitations, environmental regulations, overcapacity, and increasing fuel prices raised production costs. Some industrial firms, for the first time in decades, all of the sudden found it economical to generate their own electricity. Because of the monopoly held by utilities on transmission and distribution, however, it was difficult to sell their excess electricity to other firms. The provision of PURPA most relevant to the changing structure of the electric power industry was the requirement that utilities buy the power generated by a new class of qualifying facilities (QFs)[75] that included small power producers,[76] cogenerators,[77] and other nonutility generators.[78] The Federal Energy Regulatory Commission (FERC)[79] was charged with implementing PURPA and established regulations requiring that electric utilities purchase the electricity generated by QFs at their avoided cost of generation.[80] [20] QFs were required to met certain ownership, operating, and efficiency criteria. The end result of this law was to greatly increase the prevalence of nonutility generators. In 1979, utilities supplied 97

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[73] Some would argue that this is as it should be and will produce a more economically efficient market since the investors bare the risk of unwise capital purchases.

[74] Public Law 95-617. PURPA was part of the larger National Energy Act of 1978, which also included the National Energy Conservation Policy Act, the Powerplant and Industrial Fuel Use Act, the Natural Gas Policy Act, and the Energy Tax Act. [20]

[75] See the Code of Federal Regulations, Title 18, Part 292.

[76] PURPA defined small power producers as those that mainly use renewable energy resources for generation [20].

[77] Cogeneration is the combined production of electric power and some other form of useful energy, which is normally process steam, from a single energy source [20].

[78] Other nonutility generators under PURPA include companies that produce power for their own use and for sale to electric utilities such as independent power producers (IPPs), nonqualifying cogenerators, and other industrial facilities [20].

[79] FERC is the primary agency responsible for enforcing federal regulation of electric power transactions and replaced the Federal Power Commission in 1977. It is composed of five commissioners that are appointed by the President and confirmed by the Senate. [56]

[80] The avoided cost of generation is the incremental cost that an electric utility would incur to produce an amount of power equivalent to that purchased from the QF [20].

percent of the electricity consumed in the U.S., yet by 1991 this share had declined to 91 percent [56].[81]

Despite the growth of nonutility generators, they still could not gain access to the utilities' transmission systems, and therefore could not sell their power to anyone but their regional utility as permitted by PURPA [55]. This situation was not to remain for long, though, because in 1992 Congress passed the Energy Policy Act (EPACT),[82] which amended the Public Utility Holding Company Act (PUHCA) of 1935.[83] The ultimate effects of the EPACT are still uncertain, but essentially it will make it easier for nonutility generators to enter the wholesale market for electricity. EPACT created a new category of producers termed exempt wholesale generators (EWGs) that are exempt from PUHCA restrictions. EWGs can be owned by utilities or by other business organizations. They differ from the older PURPA QFs in that no particular generation restrictions are placed on them, and utilities are not required to purchase the power they generate.

The provision of the EPACT that is likely to have the most dramatic effect upon the electric power industry is that the FERC now has authority to order, upon application, utilities to provide access to the transmission grid for the wholesale (not retail) transmission of EWG generated electricity [49].[84] Such regulatory changes have created a situation where, unlike pre-1992, practically any business can generate electricity and sell it on the wholesale market. Utilities can be ordered by FERC to not only provide transmission services, called "wheeling",[85] but also to build facilities necessary to provide transmission services at the request of any other electric utility, Federal power marketing agency, or business generating electricity for sale [49].

As to the issue of prices that these utilities are allowed to charge other entities for providing access to their transmission and distribution network, FERC is instructed by the language of the Act to approve rates that allow the utility to recover "all legitimate, verifiable economic costs incurred in connection with the transmission services." [49] Essentially, then, the utility must provide access at cost, subject to FERC approval.

As might be expected in any rapidly changing and uncertain marketplace, the fervor following the passage of EPACT has further discouraged many utilities from investing in expensive new

[81] Much of the nonutility capacity added in the 1990's is located in Texas and California [56].
[82] Public Law 102-486. See Burkhart (1992) [10] for a review of Congress' proceedings during EPACT passage.
[83] PUHCA was designed to discourage holding companies from structuring themselves in ways that would be difficult for states to regulate [20].
[84] The portion of the EPACT significantly broadened the FERC's existing power to order the provision of electricity transmission services under §211 of the Federal Power Act [49].
[85] Wheeling services are the movement of electricity from one system to another over transmission facilities of intervening systems [19].

generating capacity. In addition, the ability of utilities to more easily trade electricity between systems has allowed them to lower their capacity margins and avoid additions by relying more on nonutility generators and by utilizing existing facilities more intensively.

Chapter 3 Literature Review

As introduced in Chapter 1, the assumptions made concerning scrappage and replacement ratios for U.S. industrial firms employing environmentally polluting processes are extremely relevant to policy making and the design of regulatory mechanisms. Clearly, these assumptions are particularly relevant to the electric power industry, which is both highly regulated and responsible for a major portion of the air pollution released by U.S. industry. If the goals for energy efficiency and pollution reduction set by government institutions are to be met, then the policies and regulations designed to help reach them must be based upon reasonable assumptions that address the factors affecting decisions on the scrappage and replacement of large capital equipment in highly polluting industries.

Much of the economic literature on capital replacement prior to the 1970's employed an assumption that replacement investment was a constant proportion of the existing capital stock. Jorgenson (1965) and Jorgenson and Stephenson (1967), in developing econometric models of investment behavior in the U.S. manufacturing sector, presumed the replacement ratio approaches a constant [33,34]. Jorgenson summarizes this belief in describing a modification on capital renewal theory when he wrote [33, p.51]:

> It is a fundamental result of renewal theory that the distribution of replacements...approaches a constant fraction of the capital stock for (almost) any distribution of replacements over time and for any initial distribution of capital stock. This result holds for a constant stock and for a growing stock as well.

Jorgenson gave evidence for his assumption by rejecting, at low levels of significance, a hypothesis stating that replacement investment is not related to the depreciation of the capital stock in the majority of the industries he studied [24].

In 1971, however, Feldstein and Foot (1971) published a study criticizing this assumption, stating that Jorgenson's evidence showing that replacement investment was related to depreciation, did not eliminate the possibility that replacement investment could be related to other short-term economic forces. They modeled investment behavior using annual data on planned manufacturing investment over the period 1949 to 1968.[86] Renewal theory was also criticized in their paper as only applying to "long-run limiting behavior of...processes under the empirically uninteresting conditions of constant growth" [24]. Instead, they proposed that plant and equipment "neither evaporate by radioactive decay

[86] Their data was taken from the McGraw Hill manufacturing industry investment surveys.

nor fall apart...; rather they are scrapped and replaced when the balance of economic forces makes that decision most profitable" [24]. Their model led them to conclude, both, that there was significant variation from year to year in the ratio of replacement investment to the capital stock and that its determinants were the internal availability of investment funds, pressure for expansion investment, and capacity utilization. Discarded as determining factor was the age of the capital stock. In summary, Feldstein and Foot found that the assumption of constant proportional replacement of capital could potentially be true in the long run, but that it was false on a year by year basis. [24]

One of the assumptions made by Feldstein and Foot was that firms will purposely time replacement investment for periods of low expansionary investment activity [24]. Eisner (1972), soon after, criticized this assumption and instead found in his analysis using similar data over the years 1951 to 1970, that replacement and modernization expenditures were not a substitute for expansion expenditures, but instead were positively related. Overall, however, Eisner confirmed the conclusions of Feldstein and Foot, that "expenditures planned for replacement and modernization varied over time...and were not a constant proportion of capital" [16].

An excellent review of the issue was soon after presented by Feldstein and Rothschild (1974) in which they provided clarifying definitions for some of the variables being used in the ongoing debate. They decomposed the issue by interpreting the *deterioration* of capital to be the increase in real input resource cost per unit of output as equipment ages.[87] *Depreciation* was then defined as the fall in the value of a piece of equipment as it ages. They went on to state that if there are no installation costs and no uncertainty is involved, then the rate of depreciation directly reflects the rate of deterioration and the rate of technological obsolescence. Otherwise depreciation cannot be assumed to be an accurate measure of deterioration. *Scrappage* was also specifically defined as "the complete withdrawal of a piece of equipment from a firm's capital stock," which was done whenever a firm can no longer earn a positive rent on a piece of equipment. [25] Similarly, *replacement investment* was described as the "actual purchase of equipment to maintain the output capacity that is lost through" deterioration and scrappage. Because a firm can engage in maintenance activities, and therefore control the deterioration and scrappage of its capital, both deterioration and scrappage are necessarily economic choices and not fixed processes. Feldstein and Rothschild rejected the assumption that over the long-term the replacement ratio approaches a constant. They resolved that only under the economically insignificant circumstances of constant exponential deterioration of the entire capital stock or constant exponential

[87] Deterioration was further decomposed into output and input decay. According to Feldstein and Rothschild, output decay is the reduction in output as a piece of equipment ages, while input decay is the increased inputs required by equipment to maintain the same level of output as it ages.

growth in capital stock was such an assumption appropriate. They then concluded that the planned lifetime of equipment, including short and long-run replacement ratios, were sensitive to changes in both the interest rate and tax laws. Also found as an important factor was the uncertainty in delivery lags for new ordered capital equipment. In summary, their findings were consistent with Feldstein and Foot and Eisner before them, in that the assumption of a technologically constant rate of replacement is incorrect and that there are significant fluctuations in replacement investment. [25]

Later studies agreed with Feldstein and Foot's conclusions and gave further support for the rejection of a constant replacement ratio. Nickell (1975) presented a careful theoretical explanation of why replacement investment would behave as if capital deteriorated exponentially only on a long-run average basis at best, and then only if the average long-run demand growth was constant. He showed that if the amount of replacement occurring over a given period was of interest, then the assumption of exponential deterioration and therefore replacement investment was invalid. [45] More recently, Bischoff and Kokkelenberg (1987) found, by looking at U.S. total manufacturing quarterly data, it to be both statistically and economically significant that physical capital depreciates more rapidly when it was used more intensively.[88] Although this conclusion would appear to be nothing more than common sense, much of the earlier economic literature on investment demand did not take this factor into account. Utilization is, therefore, another important factor in determining deterioration and scrappage.

The majority of the studies that have looked at economic depreciation and scrappage have been focused on the second-hand automobile and truck markets. More recently, even those studies, which had previously attempted to model depreciation as a simple exponential decay, have begun to focus on consumer replacement and scrappage decisions as being governed by multiple economic, technological, and regulatory factors. See Golddin (1983) and Miaou (1995) for recent work on vehicle scrappage [39,41]. Hahn (1995) presents an excellent review of the history of automobile scrappage studies, and Perry and Glyer (1990) give support to Feldstein and Rothschild's work in an examination of depreciation of farm tractors [29,50].

The first authors to apply an econometric analysis to replacement in the electric power industry were Bitros and Kelejian (1974) [8]. Again, like Feldstein and Rothschild, they found it necessary to criticize the assumption that replacement investment is a constant proportion of the existing capital stock. Their study employed annual data from the Edison Electric Institute covering U.S. electric utilities over the period 1946-1971. They found that for the electric power industry the scrappage ratio

[88] Unlike Feldstein and Rothschild, Bischoff and Kokkelenberg do not, unfortunately, make the useful distinction between deterioration and depreciation.

was significantly related to gross investment, maintenance expenditures, and the interest rate. They further concluded that since the replacement ratio is a function of the scrappage ratio, that it must also be related to the same economic variables. A few years later, Cowing and Smith (1977) published a study which criticized Bitros and Kelejian's methodology, but supported their findings [13]. In their model, they used the same data from Bitros and Kelejian's study, but revised it for what they saw as misinterpretations in generator capacity rating adjustments and aggregations across different types of utility firms. In the end though, their results provided even stronger support for the conclusions made by both Feldstein and Rothschild, and Bitros and Kelejian.

Other studies have been published on the effects of regulation on the electric power industry, especially the effects of environmental regulation. Joskow and Rose (1985) looked specifically at coal-fired units constructed between 1960 and 1980 [36]. They concluded that the addition of scrubbers and cooling towers by electric utilities in an effort to comply with air and water pollution regulations had added at least 20 percent to the real construction costs of those coal units. They also found that these costs were still only a small fraction of the total increase in real construction costs seen during the 1970s. Overall they stated that real construction costs had increased by 80 percent from 1960 to 1980 due to environmental regulation, increased construction times, and declining construction productivity. Later, Joskow (1987) looked at two additional years of data and found that the real costs of building coal units increased by at least 100 percent between 1965 and 1982 [35]. He agreed with Joskow and Rose, concerning the determinants of these increases, but also found that the rate of growth in real costs slowed significantly after 1976. Decreasing improvements in new unit thermal efficiency and deterioration in aging units were also shown to be causing a slowing of improvements in the average thermal efficiency of the industry.

Other implications of regulation in the electric power industry have been studied. The ability of rate of return regulation by Public Utility Commissions to influence the rate of technical change for forty privately owned utilities during 1951 and 1978 was investigated by Nelson (1984) [43]. He found that rate of return regulation had little impact upon encouraging technical change. A potential problem in Nelson's approach, however, is in the assumption he made concerning technical change. His results are more applicable to conclusions addressing capital turnover because he had assumed that technology was not only embodied in new capital, but that it could also be indexed or measured simply as a function of average age, or vintage, of that capital. Fuller (1987) presented evidence that fossil-fueled powerplant capacity factors were reduced in response to tighter controls on fly ash[89] emissions from 1965 to 1975, and that most utilities were switching to lower ash producing fuels to reduce compliance costs [26]. More recently, Yaisawarng and Klein (1994) estimated productivity changes for 61 coal-fired powerplants during 1985 and 1989, and found that, in general, productivity had decreased as a result of the equipment and methods used to control SO_2 emissions.

Lastly, Nelson, Tietenberg, and Donihue (1993) completed a study which tested the hypothesis that differential regulation of new sources versus existing sources reduced the rate of capital turnover for 44 privately owned utilities operating between 1969 and 1983 [44]. They believed that applying more stringent regulations to new sources, would raise utility costs and encourage the continued operation of existing sources, and thereby reduce the rate of capital turnover. If new plants were generally cleaner than existing ones, as the regulations required, then capital turnover would be expected to reduce overall emissions. Their results indicated that regulation did indeed lead to the increase in the average age of capital by 3.29 years (25%), but that this increase in age did not have a statistically significant effect upon SO_2 emissions. Additionally, they calculated that in the absence of both new and existing source regulations, that SO_2 emissions would have increased by 3.79 tons per gigawatt-hour (35%).

In summary, although all of these studies do not necessarily focus upon coal-fired units in the electric power industry, they show how it has become increasingly clear that both economic and regulatory factors have a strong influence on capital scrappage and replacement decisions. Similarly, many of these factors are related to environmental regulation and the costs associated with utility attempts to comply with emission limitations. The more recent factor, which has not been investigated, however, is the effect of the EPACT and the ongoing deregulation of the industry.

[89] Fly ash consists of impurities consisting of silica, iron, alumina, and other noncombustible matter that are contained in coal. It increases the weight of coal, adds to the cost of handling, can affect its burning characteristics, and produces particulate emissions if not controlled. It is removed from the flue gas using particulate collectors such as fabric filters and electrostatic precipitators. [19]

Chapter 4 Evidence

In the previous chapter, the first of the central questions was addressed, namely the assumptions appropriate for assessing decisions made in the electric power industry concerning the scrappage and replacement of coal-fired generating units. In answering the second central question, quantitative evidence is needed to describe both the current industry trends associated with aging coal units and some of the factors influencing them. As the industry matures, its growth potential, cost structure, regulatory system, and the competitiveness of its market are undergoing significant changes. New trends are emerging as a result of these changes including, for example, the repowering and life extensions of older powerplants, both of which allow utilities to forestall more expensive capacity expansions through the construction of new "greenfield" facilities.

The evidence presented in this chapter is organized into six major sections. The first includes a brief discussion of the major sources of data used in supporting the claims made about aging and utilization patterns. The second section provides conclusive evidence that the capital stock of coal-fired generating units in the U.S. is aging significantly. Utilization trends in the industry, given the growing demand for electricity, will then be discussed in the third section. Past and planned retirements of older coal units are addressed in section four, followed by an examination of repowering trends in the industry. Section six looks at historical data on the amount of added coal-fired capacity and the level of future capacity additions that are currently planned, and lastly, issues influencing planning by utilities and nonutilities for future capacity are discussed in section seven. Together, these sections will present some clear trends in the electric power industry that have important implications, especially for the formulation of environmental policy.

4.1 Brief Discussion of Data Sources

The major source of data to be used in the analyses presented below was obtained from the U.S. Department of Energy's (DOE) Energy Information Agency (EIA). A database of over 12,000 observations covering the reporting years 1985 through 1994 was obtained for all the generating units within the U.S. which use any form of coal as their primary energy source. Data on each unit's age and annual figures on generation and capacity will be the focus of the analysis given below. Because it is adjusted for minor modifications in capability, the summer capacity[90] of each unit has been used to calculate all capacity factory[91] values, although the qualitative conclusions made are not altered if nameplate capacity[92] is used instead. Also, a select few observations were eliminated from the dataset as outliers after careful examination. The complete dataset was also used to re-perform major components of the analyses presented below, and no significant differences were found, implying that removal of these outliers did not present any practical bias. For a more detailed discussion of how the modified EIA dataset was prepared, see *Appendix: Discussion of Data Sources*.

Also enlisted to provide corroborating evidence were two datasets from NERC. The first was the Generating Availability Data System (GADS) which includes aggregate data on electric generating units representing 92 percent of the installed capacity in the U.S. and Canada. One-hundred and eighty utilities voluntarily participate in GADS. The system, however, is tainted with generating units in Canada and Mexico, does not represent all coal-fired units in the U.S., and provides only highly aggregated summary information for 1990 through 1994; therefore, it is not as useful or comprehensive as the EIA database.[93] The second dataset from NERC is the Electricity Supply & Demand (ES&D) database, which provides summary information on electricity supply and demand projections for participating electric utilities in NERC's ten regions. ES&D includes data on specific planned retirements, repowering, and unit additions which can be disentangled from units in Canada or Mexico also belonging to NERC; however, again it does not include all generating units in the U.S.

4.2 Aging Data

By the year 2000, if the current stock of coal-fired capacity in the U.S. continues to be supplemented with very few additions or retirements, then over 37 percent of its capacity and 67 percent of its units will be more than 30 years old. DOE estimates that by 1998, between 3,500 and 3,700 units of all types will be more than 30 years old [15].[94] Below, data is presented that depicts a clear trend in the average age of coal-fired generating units in the U.S. In considering this age data, it should also be kept in mind that concurrent with the trends discussed, the total demand for electricity in the U.S. continued to grow. In addition, generation from coal-fired units has also grown, as shown in

[90] Summer capacity is the steady hourly output that a generating unit is expected to supply, as demonstrated by tests at the time of summer peak demand for electricity [19]. It is generally somewhat lower than the unit's nameplate capacity rating. Generating units are also rated for their winter capacity.

[91] The capacity factor (CF) of an individual unit is the ratio of the average load on the unit for the period of time considered to its capacity (summer in this case).

[92] Nameplate capacity is the full-load continuous rating of a generator under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated by a nameplate attached to the generator. [19]

[93] GADS contains data on 128 utilities operating a total of 883 coal-fired generating units in 1994.

[94] This number of units is roughly 34% of the 10,448 units existing in 1994 [19].

Figure 9 which is drawn so that capacity is proportional to generation. Although total coal-fired capacity increased slightly over the ten years, demand growth out paced it, causing units, in general, to be operated at higher capacity factors. This fact will be addressed in greater detail in the following section on utilization, but it should nonetheless be kept in mind while reviewing the age data in this section.

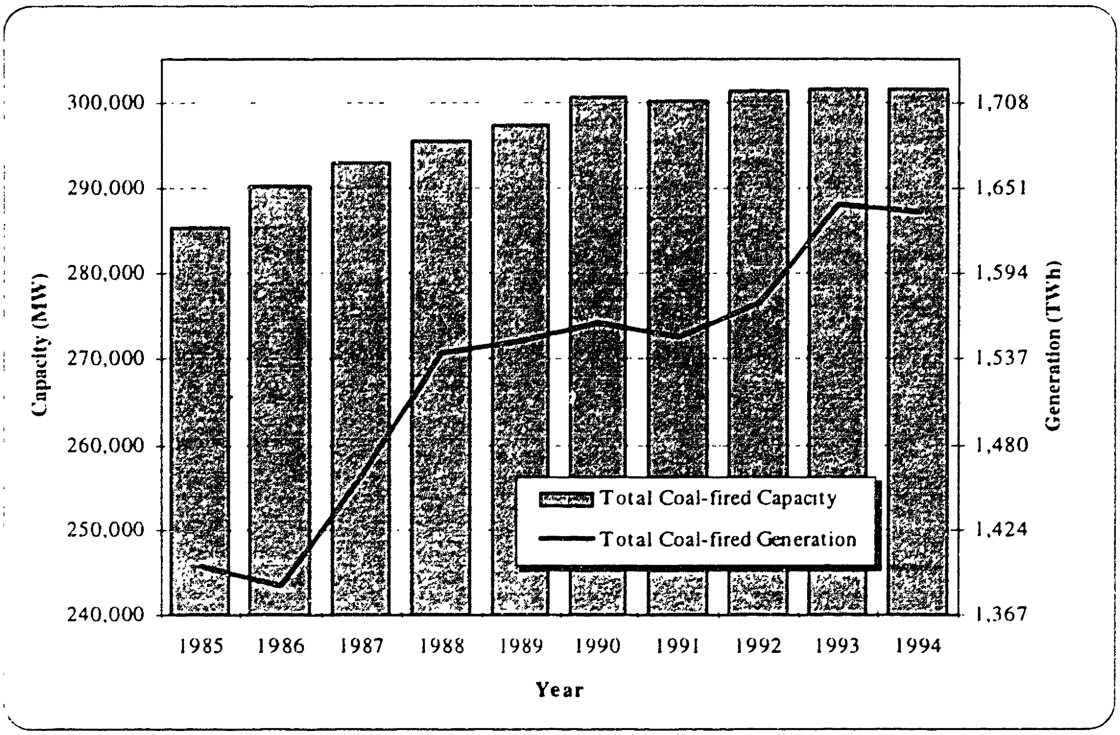

Figure 9: Growth in Total Coal-fired Capacity and Annual Generation (1985-1994)[95]

Using the modified EIA dataset, average age values for the stock of coal-fired units in the U.S. were calculated, and are presented in Table 2. Also given are the average ages weighted by summer capacity and unit generation. In all three cases over each reporting year period, the average ages increase by nearly a full year, implying that few units are being retired or added.[96] The difference in years between the average age in 1985 and 1994 is 7.7 for each unit, 8.0 for each MW of summer capacity, and 7.4 for each GWh of electricity generated. The average age weighted by capacity and generation is significantly lower, as would be expected, since newer units have tended to be larger and

[95] In this graph, the right-hand scale for generation (TWh) is proportional to the capacity scale by a factor of 0.65; therefore as the generation line approaches the top of the capacity bars, the national average capacity factor is approaching 65%. Source of data: DOE/EIA unmodified dataset. See Appendix for discussion of data sources.

[96] See section *4.6 Unit Additions*.

used more intensively, on average, than older units.[97] This fact is supported by the data presented in Table 3, which looks at average age values by the generating capacity of the unit. In both tables, F-statistic probability values (p values) are given. These values are derived from an Analysis of Variance (ANOVA) table, which expresses the level of significance appropriate in interpreting that there is a statistically valid difference between the average values listed. In every case, the tests showed that these differences are highly significant, below the 0.005 percent level. The F-statistic p value is also given to help judge the significance in differences between capacity factors in the following section.

Table 2: Average Age of Coal-fired Units, Capacity, and Generation (1985-1994)[98]

Reporting Year	Average Age of (Years)			Number of Observations
	Each Unit	Each MW of Summer Capacity	Each GWh of Electricity Generated	
1985	22.71	14.58	13.83	1197
1986	23.46	15.25	14.61	1206
1987	24.40	16.16	15.35	1219
1988	25.37	17.04	15.99	1227
1989	26.10	17.87	16.97	1212
1990	26.89	18.72	17.72	1221
1991	27.70	19.60	18.31	1218
1992	28.60	20.55	19.26	1211
1993	29.50	21.57	20.41	1202
1994	30.39	22.55	21.25	1196
F-Statistic p Value	0.00%	0.00%	0.00%	

In interpreting the information presented in Table 3, several things should be noticed. First, clearly the aging trend seen above in Table 2, is occurring regardless of the size of the unit. In general, though, smaller plants tend to be older than larger plants. Over the years, the technological changes and the economy of scales in construction and electricity production has favored the building of increasingly large units. More recently, however, the optimum unit size has stabilized and is considered to be around 500 MW [56].[99]

[97] See Figure 13, Figure 14, and Figure 24.
[98] Source of data: DOE/EIA.
[99] See section 4.6 *Unit Additions*.

Table 3: Average Age of Coal-fired Units by Generating Capacity Range (1985-1994)[100]

Reporting Year	Average Age of Units (Years) Values in Parentheses are Number of Observations/Units Lower Values are the Total Capacity Represented (MW) by the Category								
	Generating Capacity Range (MW)								
	0-99	**100-199**	**200-299**	**300-399**	**400-499**	**500-599**	**600-699**	**700-799**	**800 +**
1985	30.76 (463) 19,595	25.98 (263) 37,471	20.11 (122) 29,265	13.92 (78) 26,889	8.45 (58) 26,050	10.50 (88) 47,856	8.33 (58) 36,972	9.56 (36) 26,544	10.39 (31) 29,933
1986	31.52 (468) 19,466	26.91 (257) 36,406	21.05 (125) 29,998	14.90 (78) 26,939	9.36 (59) 26,535	11.28 (88) 47,790	9.10 (61) 38,872	10.35 (37) 27,287	10.67 (33) 31,541
1987	32.41 (479) 19,998	27.80 (256) 36,515	21.98 (128) 30,722	15.38 (77) 26,724	10.55 (58) 26,011	12.20 (88) 47,650	10.08 (62) 39,649	11.11 (37) 27,316	11.32 (34) 32,341
1988	33.53 (482) 20,224	28.64 (258) 36,863	23.06 (126) 30,252	16.51 (77) 26,637	11.30 (61) 27,350	13.21 (89) 48,264	10.79 (62) 39,667	12.08 (37) 27,334	12.00 (35) 33,230
1989	34.22 (464) 19,653	29.69 (259) 37,153	24.22 (125) 29,884	17.36 (78) 27,015	12.20 (61) 27,406	14.28 (89) 48,281	11.60 (63) 40,395	13.42 (36) 26,682	12.32 (37) 35,372
1990	34.87 (463) 19,867	30.64 (266) 38,181	25.27 (123) 29,414	18.10 (80) 27,724	12.81 (58) 26,020	15.34 (94) 50,957	12.32 (63) 40,490	14.42 (36) 26,683	13.00 (38) 36,671
1991	35.47 (461) 19,915	31.69 (271) 38,674	25.76 (118) 28,301	19.09 (78) 26,970	14.89 (62) 27,816	15.85 (91) 49,574	13.07 (61) 39,258	15.24 (37) 27,356	13.92 (39) 37,411
1992	36.44 (452) 19,803	32.73 (274) 39,125	26.46 (114) 27,406	20.24 (79) 27,261	15.65 (62) 27,870	17.16 (95) 51,824	13.56 (59) 38,162	16.24 (37) 27,364	14.92 (39) 37,444
1993	37.28 (440) 19,535	33.76 (275) 39,156	27.69 (115) 27,468	21.46 (80) 27,633	16.90 (60) 26,909	18.11 (95) 51,780	14.26 (58) 37,367	17.28 (40) 29,471	15.92 (39) 37,441
1994	38.10 (433) 19,466	34.77 (278) 39,593	28.61 (114) 27,261	22.47 (79) 27,267	17.98 (59) 26,430	18.87 (97) 52,805	15.28 (57) 36,715	18.23 (40) 29,439	16.92 (39) 37,374
F-Statistic p Value	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

As supporting evidence, the unweighted average age numbers reported for 1990 through 1994 by NERC for participating coal-fired units in both the U.S. and Canada are shown in

[100] Source of data: DOE/EIA Capacity ranges in table are more precisely: 0-99.999, 100-199.999, ... , etc.

Table 4.[101] These values corroborate the overall aging trend shown in Table 2. Also presented for comparison purposes, but will not be discussed, are average age data for oil-fired steam, natural gas-fired steam, gas turbine, nuclear, and hydroelectric units from NERC.

Table 4: NERC Average Age of GADS Participating Generating Units[102]

NERC GADS Survey Average Age of Units (Years)						
Survey Year	**Coal-fired Steam**	**Oil-fired Steam**	**Gas-fired Steam**	**Gas Turbine**	**Nuclear**	**Hydro**
1990	25.18	27.61	29.33	18.10	11.61	38.14
1991	26.11	28.89	30.13	18.73	12.16	39.07
1992	27.07	28.75	31.10	19.28	13.05	40.44
1993	28.04	30.68	31.46	19.19	13.61	38.52
1994	29.00	30.36	32.92	20.75	14.41	39.19

Simply for the purpose of revealing the underlying distribution of unit ages used in calculating these averages, Figure 10 shows how both the bulk of coal-fired units and their mean ages are shifting as few units are added or retired. This aging trend is illustrated in a similar, but even more striking manner, in Figure 11, Figure 12, Figure 13, and Figure 14, which present the the amount of electricity generated by unit age in 1985 and then in 1994 and the total amount of capacity by each age group in 1985 and 1994, respectively. Again, clearly a drastic shift in the age distribution of both has occurred.

[101] The vast majority of the coal capacity covered by NERC is in the U.S. Only 6.75% is located in Canada, and none in Mexico. NERC members operated approximately 96% of the coal capacity in the U.S.
[102] Source: GADS Generating Availability Report [27].

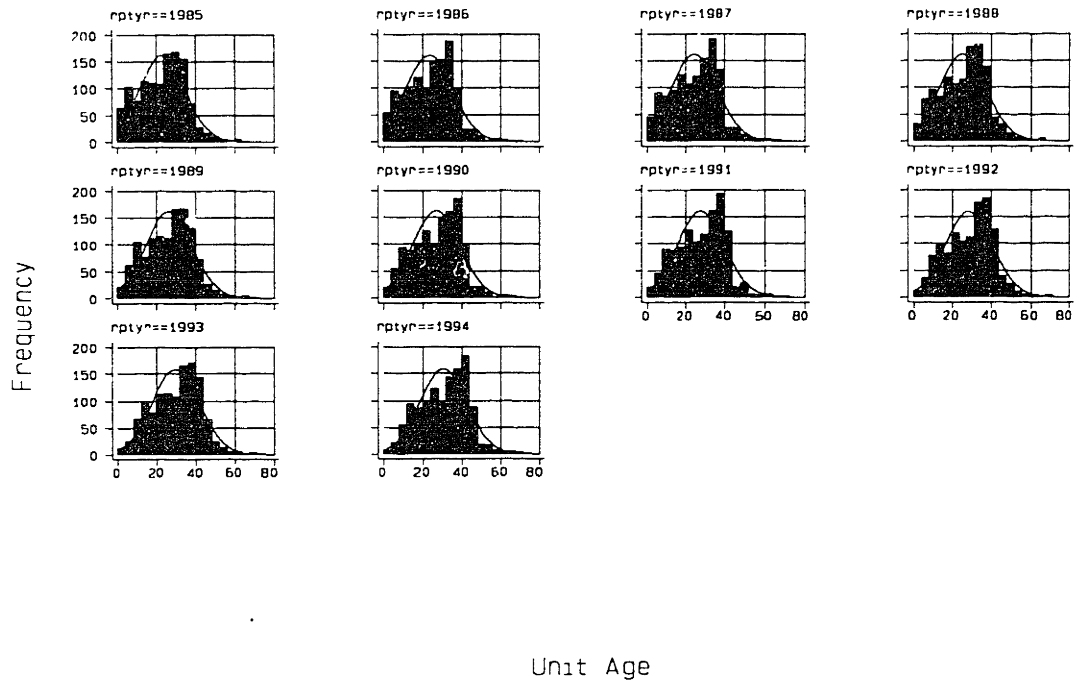

Figure 10: Age Distribution of Coal-fired Units by Reporting Year (1985-1994)[103]

[103] Source of data: DOE/EIA.

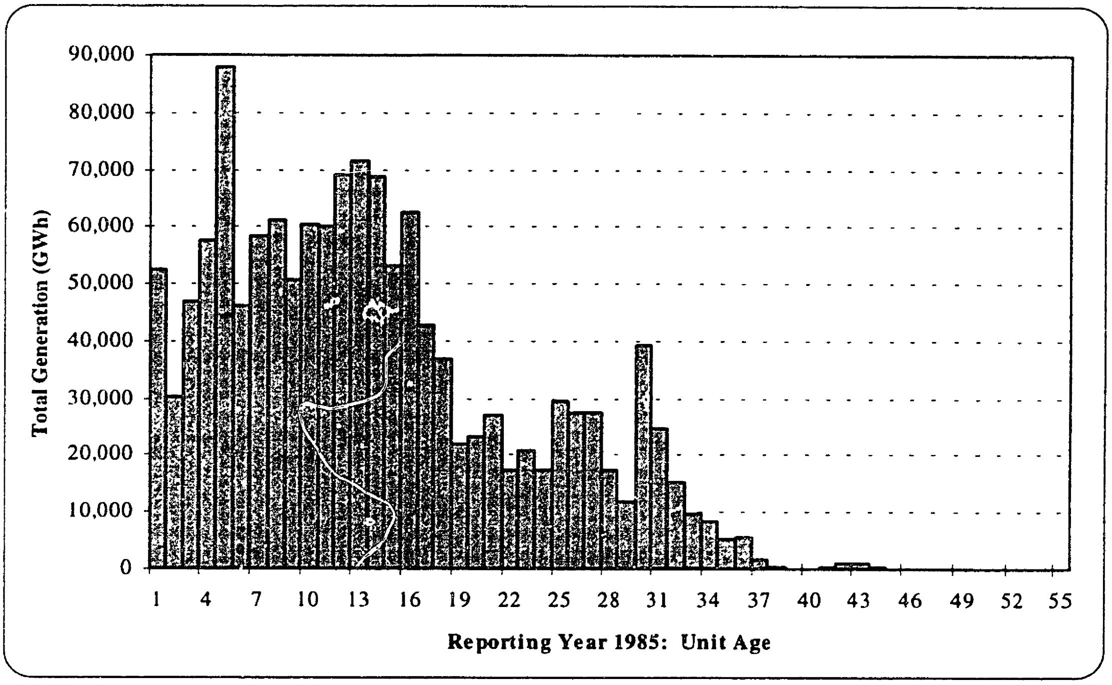

Figure 11: Reporting Year 1985 Total Generation by Unit Age for Coal-fired Units[104]

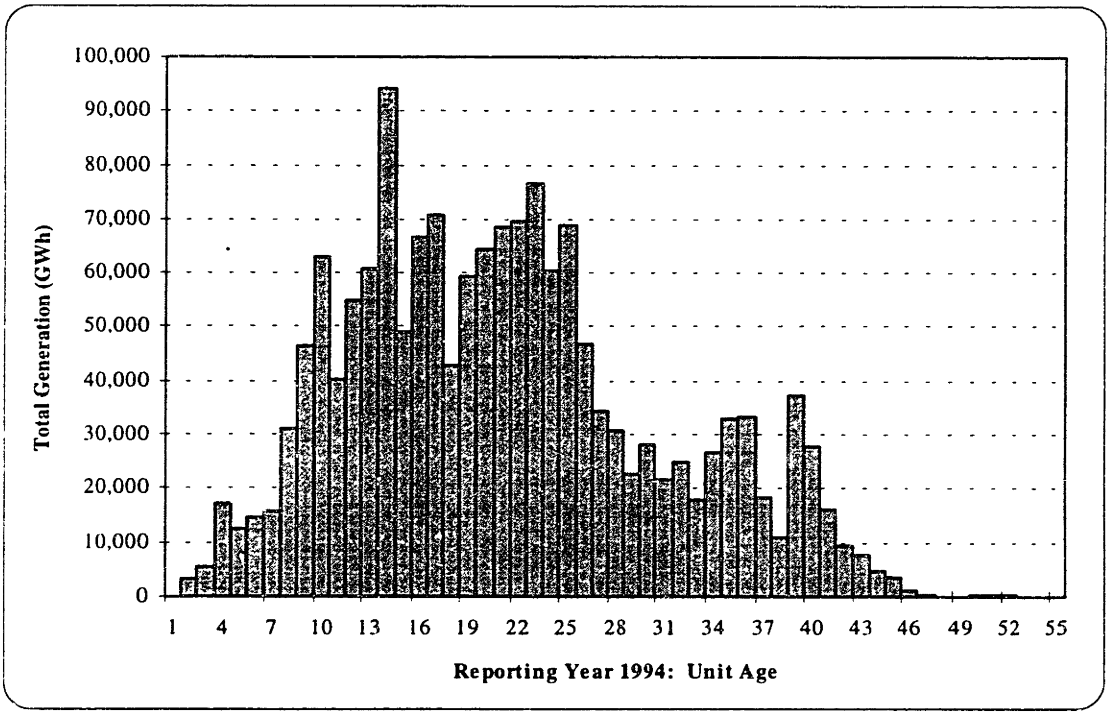

Figure 12: Reporting Year 1994 Total Generation by Unit Age for Coal-fired Units[105]

[104] Source of data: DOE/EIA.
[105] Source of data: DOE/EIA.

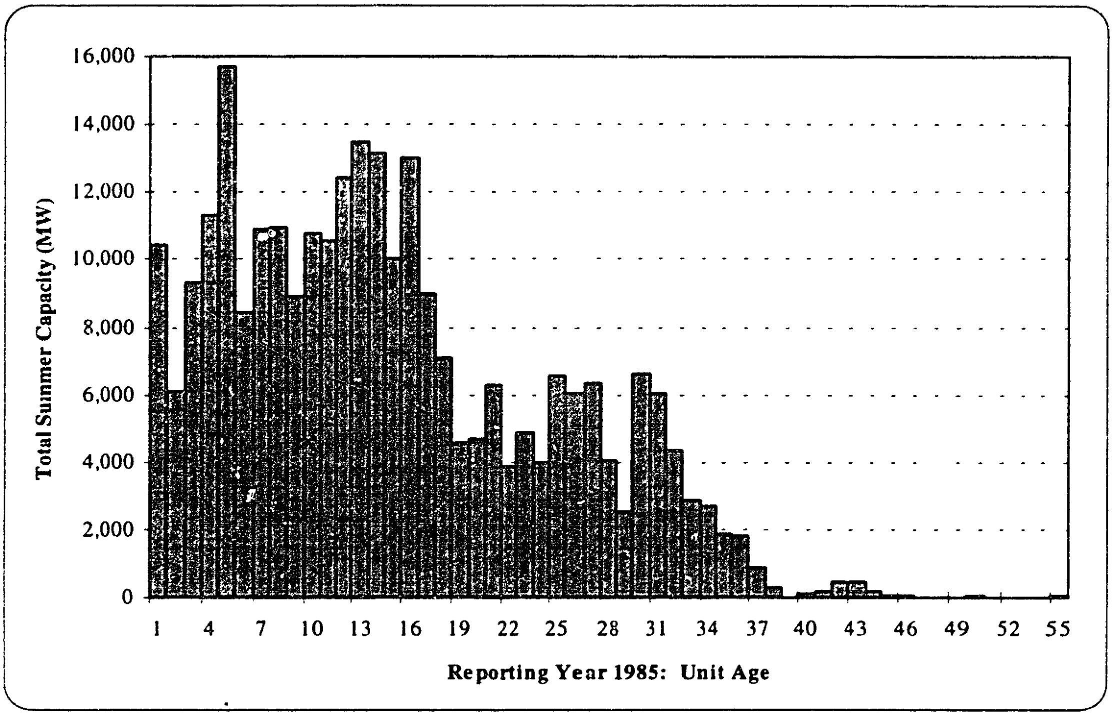

Figure 13: Reporting Year 1985 Total Summer Capacity by Unit Age for Coal-fired Units[106]

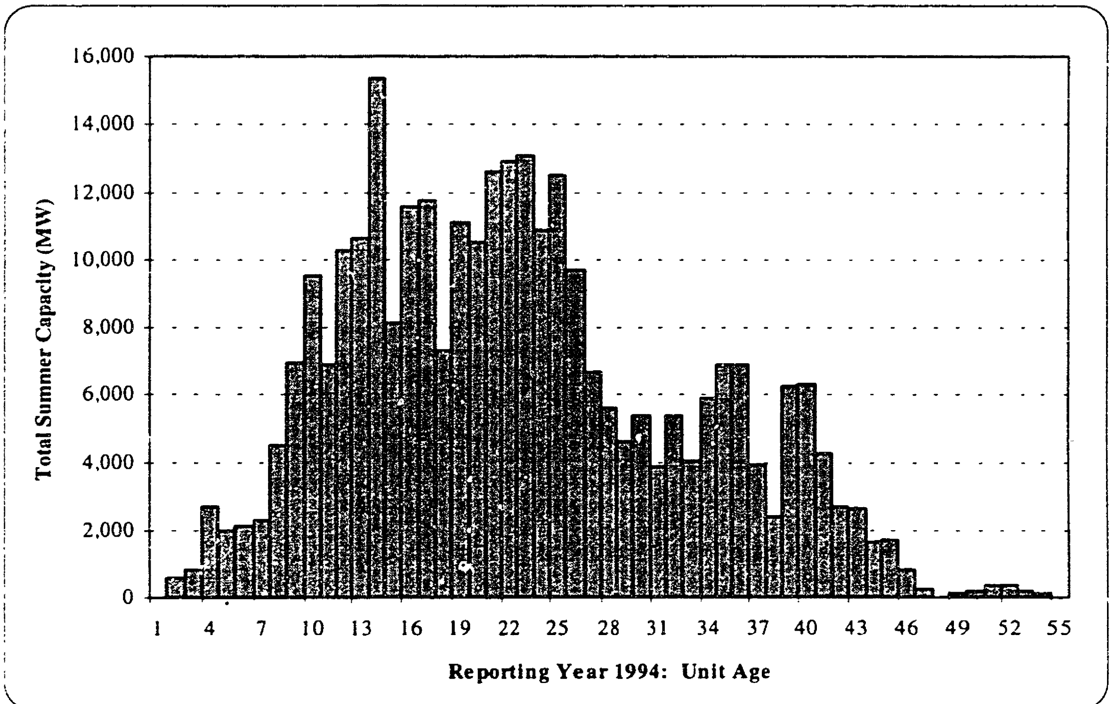

Figure 14: Reporting Year 1994 Total Summer Capacity by Unit Age for Coal-fired Units[107]

[106] Source of data: DOE/EIA.

[107] Source of data: DOE/EIA.

Evidence for three important trends was supplied or implied by the figures and tables given in this section. First, the capital stock of coal-fired units are unquestionably aging. Second, the amount of electricity being generated is increasing faster than capacity is being added. Third, it was implied that this is occurring because there have been few unit additions and/or retirements in the last ten years. Given these three trends, the last of which will be supported in subsequent sections, it is now appropriate to investigate which coal-fired units, despite the fact that they are aging, are being utilized to meet an increasing load.

4.3 Utilization

Above, it was documented that the stock of coal-fired units in the U.S. is aging. In Figure 9 it was implicit that the overall utilization level of coal-fired units was also increasing, as capacity increased at a slower rate than load. A more detailed quantification of this trend of increased utilization of coal units, represented by their annual capacity factor (CF),[108] is the subject of this section. Table 5, below, shows that the average annualized CFs for each coal-fired unit and for each MW of coal-fired capacity has quite clearly increased over the ten years of this analysis at extremely high levels of significance.[109] The higher values seen for the average CF for each MW of capacity is a consequence of the fact that there are many small coal-fired units which are only operated at times of high demand or as a result of forced outages, and therefore they have low CFs. As with the age data in the previous section, the numbers presented in Table 6, from NERC, corroborates the trend of increasing CF values.[110] Figure 15 simply illustrates the data presented in Table 5, graphically, again showing the overall increase in coal unit utilization.

[108] All capacity factor (CF) values were calculated using the following formula:

$$CF = \frac{Generation(MWh)}{Capacity(MW) \times 8766 hours}$$

[109] Actually, the p value of the F-statistic test only measures whether there is a significant difference between one or more of the average capacity factor values, but obviously the differences are the result of increased capacity utilization over time.

[110] The same limitations on the NERC Gross Capacity Factor data, as on their average age data, must be applied.

Table 5: Average Coal-fired Capacity Factor Values for Units and Capacity (1985-1994)[111]

Reporting Year	Average CF of Each Unit	Average CF of Each MW of Capacity	Number of Observations
1985	0.423	0.570	1185
1986	0.406	0.556	1196
1987	0.420	0.573	1213
1988	0.437	0.602	1224
1989	0.447	0.603	1210
1990	0.441	0.601	1214
1991	0.428	0.591	1216
1992	0.435	0.600	1210
1993	0.463	0.622	1202
1994	0.462	0.623	1195
F-Statistic p value	0.00%	0.00%	

Table 6: NERC Average Capacity Factor Values of GADS Participating Coal-fired Generating Units[112]

NERC GADS Survey Unit Average Gross Capacity Factor						
Survey Year	**Coal-fired Steam**	**Oil-fired Steam**	**Gas-fired Steam**	**Gas Turbine**	**Nuclear**	**Hydro**
1990	0.604	0.299	0.297	0.017	0.672	0.531
1991	0.594	0.283	0.292	0.017	0.706	0.515
1992	0.603	0.236	0.298	0.012	0.707	0.504
1993	0.627	0.246	0.294	0.014	0.702	0.455
1994	0.613	0.230	0.310	0.021	0.737	0.398

[111] Source of data: DOE/EIA.

[112] Source: GADS Generating Availability Report [27].

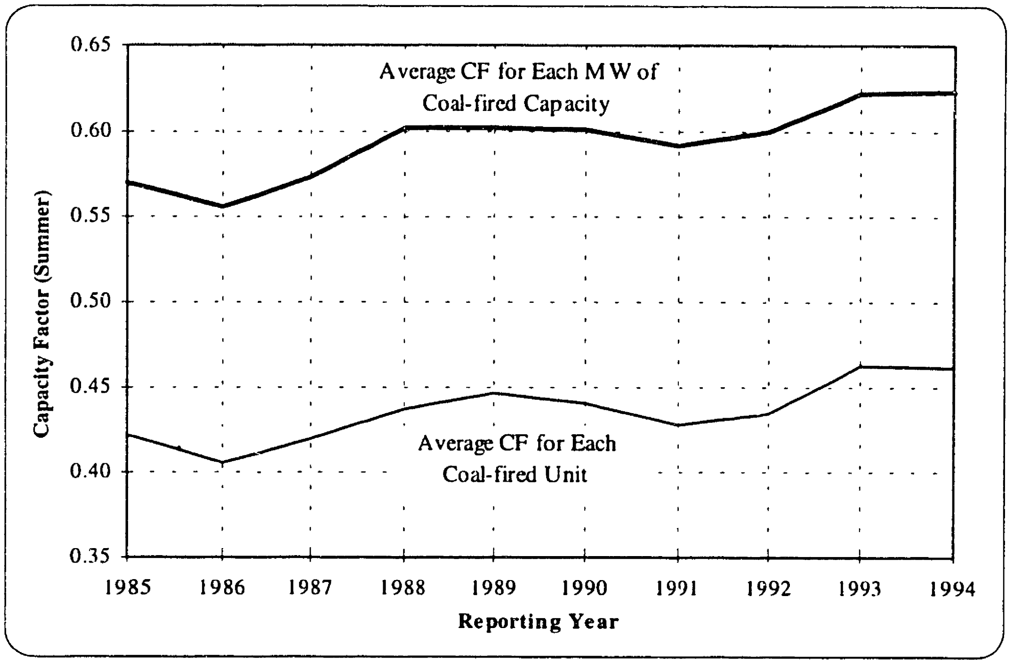

Figure 15: Average Coal-fired Capacity Factor Values for Units and Capacity (1985-1994)[113]

In an effort to decompose the distribution of generating capacity that went into calculating the average CF for each reporting year, Figure 16 and Figure 17 are given for the reporting years of 1985 and 1994. Both figures show that the distribution is skewed towards the right, with a longer tail of low CFs capacity, and a significant number of units at very low (zero) CFs. Units with CFs of zero were included in this analysis, because the number of units which are not being operated, yet have not been retired, is relevant to this analysis. Their effect upon the analysis is minimal, however, since they represent a small amount of the overall capacity and their percentage of the total remains relatively constant over time. (See *Appendix: Discussion of Data Sources* for further information on distributional issues relevant to the calculation of average CF values.)

[113] Source of data: DOE/EIA.

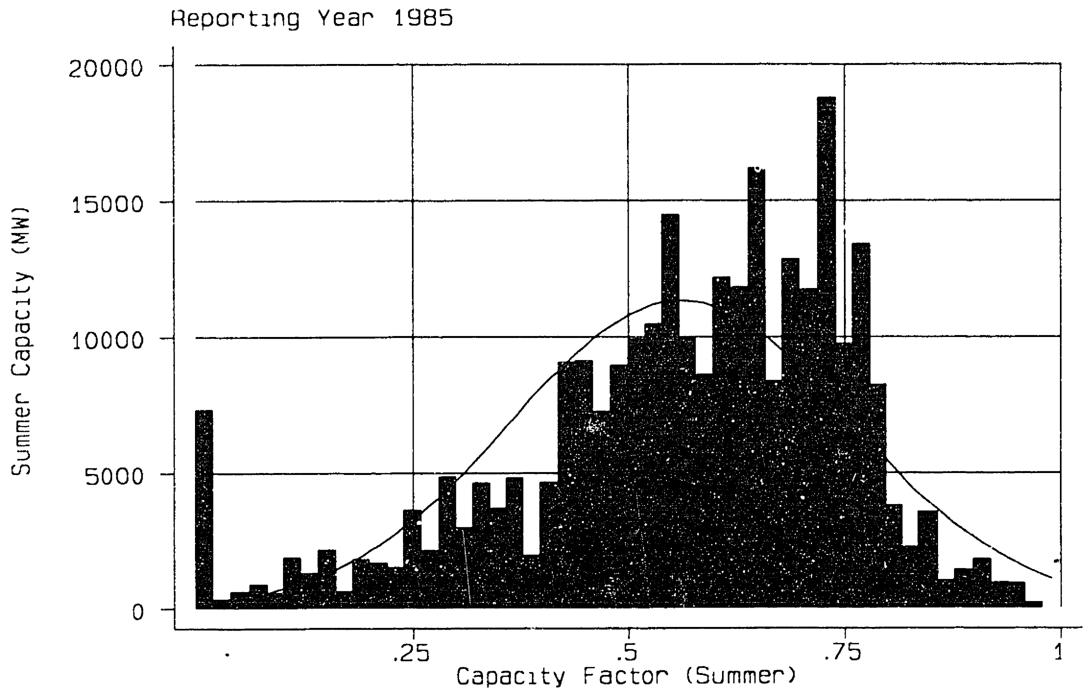

Figure 16: Distribution of Summer Capacity by Capacity Factor for Reporting Year 1985[114]

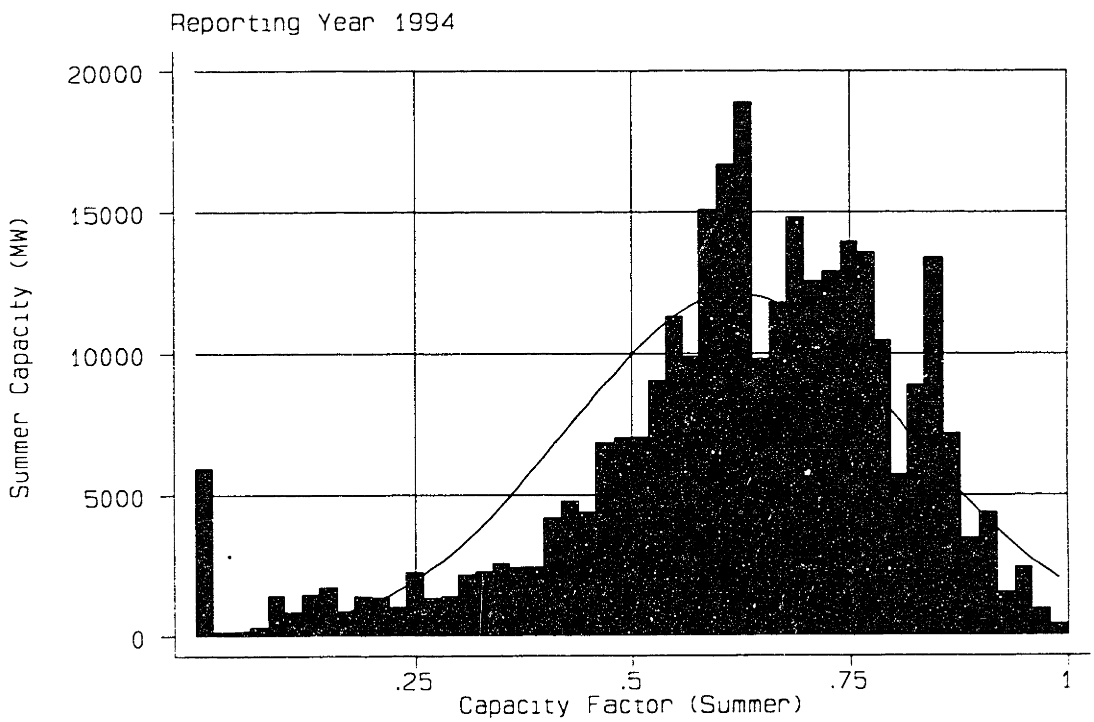

Figure 17: Distribution of Summer Capacity by Capacity Factor for Reporting Year 1994[115]

[114] Source of data: DOE/EIA.

Even though the overall utilization levels of coal units are increasing, this does not say anything about whether the trend is uniform across all ages of units and all sizes, or whether certain ages or sizes of units are seeing larger changes in utilization relative others. If older units are supplying an increasing percentage of the nation's electricity, then this would imply that higher overall pollutant emissions might also be expected, since older plants are less efficient, in general, and are subject to lower pollution control standards. Figure 18 attempts to provide some answers at the first half of this question. It shows the changing average CFs by the age of the unit, for each of the reporting years for which data was available. Additionally, the size of each data point on the graph is weighted by the amount of that year's total generating capacity that it represents.

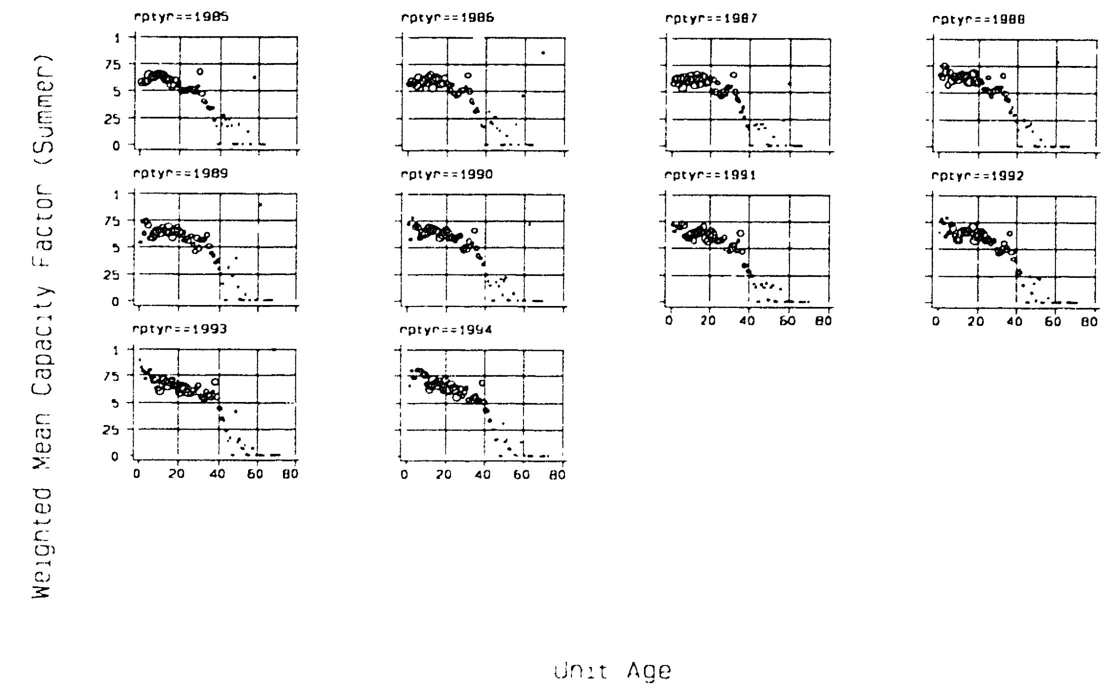

Figure 18: Average (Mean) Capacity Factors for Coal-fired Units by Unit Age and Reporting Year[116]
(The size of each data point is weighted by the portion of the total generating capacity it represents)

Clearly, there is a drop in average CF value as units get very old, as would be expected. However, on closer examination some more interesting temporal trends can be unearthed. First, the data points, overall, shift up over time, consistent with the data presented in the tables above which

[115] Source of data: DOE/EIA.

[116] Source of data: DOE/EIA. Note that in this figure, the calculation of the mean CF values themselves was weighted by the capacity of each unit included in the particular age/reporting year data point, and therefore they agree with those in Table 7.

show that aggregate CFs have been increasing. Second, the curve suggested by the data is shifting to the right, as units and capacity ages. Thirdly, in 1985 and 1986 there were relatively few units more than 20 years old, and the ones that were that old operated at only moderate capacity factors on average. By 1994, however, there was a significant amount of capacity beyond 20 years of age, and it was being operated at significantly higher average CFs.

The issue of utilization changes is also addressed, but in much greater detail, by the data presented in Table 7. Here average CF values are calculated by weighting each unit's CF by the portion of the aggregate capacity for that particular age/reporting year grouping it represented. This weighting provides a more realistic value for that particular age/reporting year cell; however, it does not represent what fraction of that year's total capacity is embodied in that cell. In other words, each age/reporting year cell does not represent an equivalent amount of generating capacity. Cells where a limited number of units (less than 10 observations) were available from which an average CF value could be calculated are shaded, to signify that they are more likely to be biased by a single observation. Again, F-statistic p values are also provided in this table to help assess the significance of the differences in average CF values seen over these 10 years.[117]

The temporal trend in average CF values for units of a given age (i.e., horizontally across rows in Table 7), in general, is upward. Some units, however, experienced larger changes in utilization than others. In particular, older units, with ages of 34 to about 40 years show larger increases in utilization than younger units.[118] This characteristic trend is also depicted in Figure 19, in which the change in a two year average CF from 1985/86 to 1993/94 for each age grouping of units is represented by vertical bars. The original CF values used to calculated the two year average, and therefore the differences, were taken from the weighted data in Table 7. The shaded area in the figure signifies, again, where less than 10 observations were available in any of the four reporting years used in determining the CF change.

[117] Again, lower F-statistic p values signify that there are more statistically significance differences between the average CF values.

[118] See Figure 14 for distribution of total summer capacity by age.

Table 7: Average Capacity Factor Values by Age and Reporting Year[119]

Age	Average Capacity Factor Values Weighted by Summer Capacity*										F-Statistic
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	p Value
1	0.573	0.557	0.579	**0.666**	**0.539**	**0.716**	**0.715**	**0.650**	**0.891**	[illegible]	28.20%
2	0.567	0.587	0.614	0.632	**0.730**	**0.575**	**0.654**	**0.767**	**0.818**	**0.654**	29.80%
3	0.575	0.561	0.627	0.742	0.624	**0.773**	**0.704**	**0.734**	**0.783**	**0.791**	1.42%
4	0.582	0.579	0.556	0.692	0.731	**0.691**	**0.691**	**0.615**	**0.713**	**0.731**	3.31%
5	0.638	0.544	0.620	0.569	0.699	0.698	**0.688**	**0.785**	**0.759**	**0.731**	0.65%
6	0.623	0.623	0.534	0.685	0.577	0.682	0.724	**0.651**	**0.794**	**0.798**	0.39%
7	0.614	0.518	0.626	0.615	0.582	0.585	0.705	0.725	**0.728**	**0.802**	0.42%
8	0.637	0.592	0.590	0.646	0.613	0.619	0.608	0.691	0.696	**0.794**	5.23%
9	0.647	0.605	0.605	0.634	0.646	0.619	0.591	0.620	0.711	0.764	2.88%
10	0.641	0.562	0.650	0.625	0.652	0.640	0.621	0.589	0.620	0.755	3.19%
11	0.650	0.620	0.618	0.658	0.626	0.688	0.632	0.585	0.597	0.666	62.79%
12	0.634	0.647	0.559	0.677	0.665	0.678	0.571	0.658	0.661	0.611	12.25%
13	0.607	0.523	0.663	0.650	0.656	0.662	0.641	0.681	0.697	0.655	0.17%
14	0.598	0.604	0.620	0.660	0.625	0.674	0.646	0.655	0.685	0.698	21.71%
15	0.604	0.616	0.573	0.602	0.682	0.655	0.681	0.663	0.644	0.686	7.41%
16	0.549	0.610	0.641	0.606	0.632	0.642	0.645	0.670	0.679	0.660	7.63%
17	0.547	0.564	0.637	0.668	0.592	0.586	0.696	0.651	0.700	0.686	0.05%
18	0.592	0.563	0.589	0.683	0.645	0.609	0.593	0.700	0.654	0.674	1.74%
19	0.548	0.618	0.597	0.605	0.671	0.632	0.566	0.577	0.650	0.611	26.16%
20	0.567	0.551	0.622	0.600	0.633	0.656	0.625	0.618	0.648	0.699	34.93%
21	0.497	0.563	0.514	0.605	0.621	0.629	0.661	0.625	0.591	0.618	1.38%
22	0.506	0.508	0.610	0.593	0.631	0.590	0.626	0.664	0.620	0.616	3.65%
23	0.483	0.560	0.497	0.531	0.556	0.593	0.586	0.634	0.647	0.669	0.06%
24	0.503	0.471	0.579	0.527	0.577	0.579	0.567	0.583	0.628	0.635	3.32%
25	0.511	0.446	0.463	0.640	0.556	0.565	0.563	0.578	0.585	0.627	0.18%
26	0.515	0.465	0.449	0.492	0.602	0.595	0.576	0.590	0.574	0.550	3.15%
27	0.493	0.501	0.493	0.466	0.518	0.611	0.569	0.543	0.611	0.587	7.23%
28	0.490	0.499	0.475	0.520	0.451	0.482	0.600	0.581	0.579	0.625	0.54%
29	0.536	0.514	0.541	0.516	0.578	0.464	0.483	0.573	0.627	0.562	9.54%
30	0.674	0.536	0.549	0.535	0.482	0.507	0.465	0.488	0.654	0.598	0.01%
31	0.467	0.644	0.554	0.538	0.562	0.481	0.483	0.452	0.556	0.637	0.04%
32	0.400	0.495	0.660	0.544	0.560	0.557	0.524	0.465	0.532	0.525	0.01%
33	0.382	0.409	0.496	0.659	0.569	0.523	0.524	0.501	0.530	0.510	0.00%
34	0.345	0.383	0.433	0.487	0.611	0.538	0.471	0.551	0.588	0.513	0.00%
35	0.332	0.309	0.411	0.435	0.498	0.654	0.568	0.479	0.561	0.548	0.00%
36	0.341	0.331	0.317	0.424	0.437	0.490	0.637	0.512	0.532	0.557	0.00%
37	0.221	0.310	0.358	0.321	0.413	0.415	0.464	0.644	0.593	0.528	0.00%
38	**0.172**	0.186	0.262	0.360	0.350	0.396	0.335	0.462	0.682	0.529	0.00%
39	**0**	**0.163**	0.189	0.293	0.371	0.339	0.335	0.402	0.545	0.683	0.00%
40	**0**	**0**	0.154	0.232	0.287	0.357	0.287	0.381	0.436	0.503	0.00%
41	**0.189**	**0**	**0**	0.160	0.246	0.246	0.277	0.270	0.433	0.428	0.04%
42	**0.266**	**0.306**	**0**	**0**	0.153	0.184	0.243	0.303	0.341	0.413	1.66%
43	0.227	**0.212**	**0.195**	**0**	**0**	**0.140**	0.167	0.279	0.322	0.330	15.69%
44	**0.170**	**0.192**	**0.207**	**0.243**	**0**	**0**	**0.134**	0.162	0.231	0.329	11.13%
45	**0.228**	**0.256**	**0.158**	**0.179**	**0.302**	**0**	**0**	**0.095**	0.130	0.246	25.35%
46	**0.173**	**0.153**	**0.203**	**0.192**	**0.148**	**0.175**	**0**	**0**	**0.162**	0.148	95.12%
47	**0**	**0.129**	**0.203**	**0.096**	**0.226**	**0.133**	**0.164**	**0**	**0**	**0.154**	88.22%

[119] Source of data: DOE/EIA. The observations used in calculating the average CF value for each cell were weighted by the portion of that age groups' capacity it represented. Note, that it is not a function of the total capacity for the reporting year; therefore, each cell does not represent an equal portion of the total capacity available for that year. See Appendix. Discussion of Data Sources for information on the amount of generating capacity underlying each cell.

48	0	0	0.164	0.210	0.070	0.203	0.128	0.242	0	0	84.08%
49	0	0	0.004	0.140	0.390	0.054	0.176	0.085	0.402	0	18.12%
50	0.184	0	0	0.008	0.124	0.187	0.019	0.180	0.114	0.298	77.79%
51		0.084	0	0	0.004	0.215	0.127	0.016	0.151	0.129	77.96%
52	0		0.082	0	0	0.002	0.154	0.233	0.070	0.154	96 64%
53		0		0.063	0	0	0.006	0.215	0.058	0.064	21.72%
54			0		0.050		0	0.001	0.091	0.058	53.72%
55	0.119			0		0.064		0	0.002		8.83%
56	0	0.190			0		0.117		0	0.007	12.08%
57		0	0.240			0		0.041		0	3.13%
58	0.625		0	0			0		0.062		0.07%
59		0.455		0	0			0		0.127	1.48%
60			0.579		0	0	0		0		
61	0			0.788		0	0	0		0	
62		0	0		0.893		0	0	0		
63	0	0	0	0		0.717		0	0	0	
64	0	0	0	0	0				0	0	
65			0	0	0	0				0	
66			0	0	0	0	0				
67				0	0	0	0	0			
68					0		0	0	0		
69		0.852				0		0	0	0	
70							0		0	0	
71								0		0	
72									0		
73										0	
	1985	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	

* Shaded areas signify where there were less than 10 observations available to calculate mean, and blank cells indicate that there were no observations for that age/year grouping.

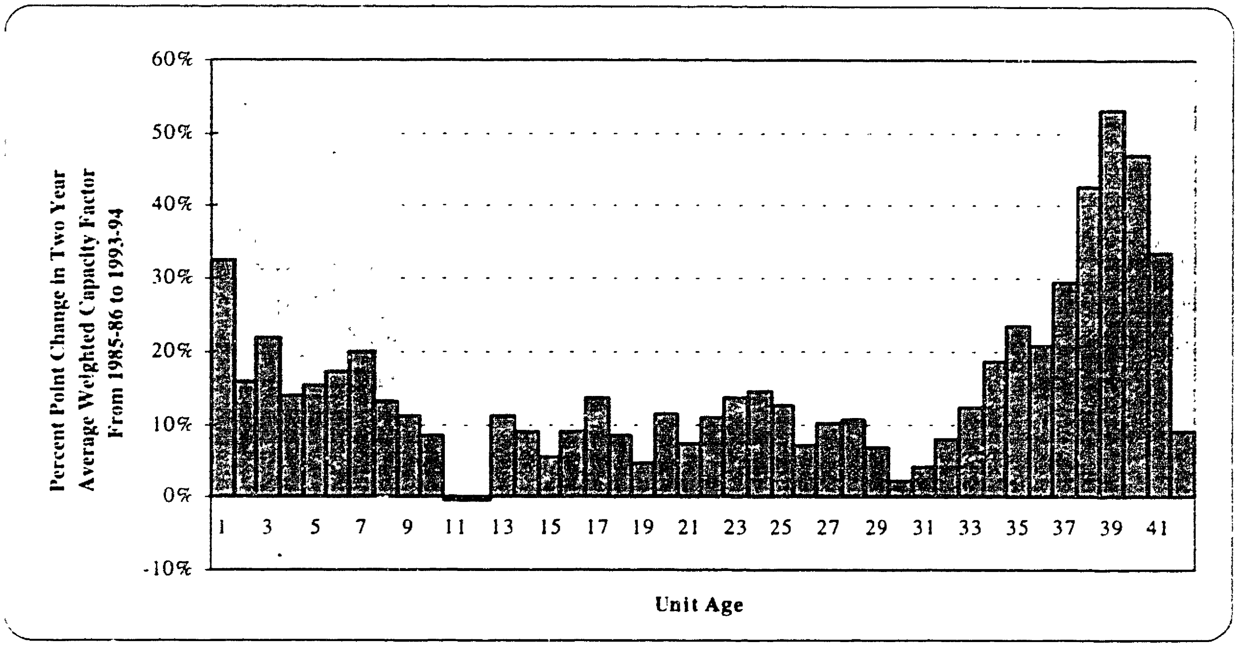

Figure 19: Change in Two Year Average Capacity Factors by Unit Age (1985/86 to 1993/94)[120]

The evidence given above has illustrated that the CFs of some older units are rising faster relative to other units. The second half of the issue introduced at the beginning of the section, as to the size of units experiencing larger increases in utilization, is now addressed by the data presented in Table 8. It indicates that small capacity and large capacity units have, on average, experienced little increased utilization. Units of intermediate sizes (100 to 699 MW), however, have been called upon to meet the bulk of the additional load. This fact is not overly surprising, however, since small units are normally more expensive to operate, and large units are likely to already be running at fairly high CFs because they are first in the dispatch order.

[120] Source of data: DOE/EIA. Shaded areas signify where less than 10 observations were available in any of the four reporting years used to calculate the change in CF. Note, that the values in Table 7 were used to calculate the value for the height of each bar. Therefore each bar does not represent an equivalent amount of capacity, nor is the capacity represented by each average value, before the difference was taken, the same.

Table 8: Average Capacity Factor Values for Coal-fired Units by Generating Capacity Range (1985-1994)[121]

Reporting Year	Average Capacity Factor of Units Values in Parentheses are Number of Observations/Units Generating Capacity Range (MW) 0-99	100-199	200-299	300-399	400-499	500-599	600-699	700-799	800 +
1985	0.196 (462)	0.513 (263)	0.596 (121)	0.577 (76)	0.610 (57)	0.583 (86)	0.597 (55)	0.657 (34)	0.621 (31)
1986	0.179 (466)	0.503 (257)	0.583 (124)	0.514 (78)	0.541 (58)	0.575 (87)	0.589 (59)	0.672 (36)	0.632 (31)
1987	0.186 (477)	0.517 (255)	0.599 (128)	0.564 (76)	0.586 (58)	0.602 (88)	0.634 (62)	0.690 (36)	0.563 (33)
1988	0.189 (482)	0.538 (258)	0.619 (126)	0.609 (77)	0.649 (60)	0.614 (89)	0.644 (61)	0.728 (36)	0.623 (35)
1989	0.199 (464)	0.538 (259)	0.630 (125)	0.602 (78)	0.665 (61)	0.623 (89)	0.650 (62)	0.710 (36)	0.598 (36)
1990	0.184 (461)	0.533 (265)	0.619 (123)	0.603 (79)	0.656 (57)	0.624 (94)	0.672 (62)	0.683 (36)	0.612 (37)
1991	0.178 (461)	0.500 (270)	0.616 (118)	0.580 (78)	0.638 (62)	0.635 (91)	0.648 (60)	0.690 (37)	0.605 (39)
1992	0.176 (452)	0.519 (274)	0.619 (114)	0.595 (79)	0.624 (61)	0.630 (95)	0.655 (59)	0.694 (37)	0.641 (39)
1993	0.188 (440)	0.567 (275)	0.660 (115)	0.607 (80)	0.672 (60)	0.645 (95)	0.675 (58)	0.700 (40)	0.641 (39)
1994	0.187 (433)	0.557 (278)	0.635 (114)	0.625 (79)	0.647 (59)	0.648 (96)	0.703 (57)	0.690 (40)	0.667 (39)
F-Statistic p Value	90.89%	0.15%	12.19%	0.60%	0.03%	1.36%	0.02%	78.20 %	38.87%

A reasonable interpretation of these trends is that utilities, because of limited additions in capacity, are attempting to increase utilization of units which are not already being operated at or near their practical utilization limit. In this case, all units are being called upon to generate more electricity, but older units because they were less utilized in the past and had a larger gap available below a practical limit to their CF, are now enduring relatively larger increases in utilization so that utilities can avoid constructing new capacity.

4.4 Retirements

One of the factors producing the trends in aging shown above is that older units are simply not being retired. From 1987 to 1994, only 2,931 MW of coal-fired capacity was retired, and much of that

[121] Source of data: DOE/EIA. Capacity ranges in table are more precisely: 0-99.999, 100-199.999, ... , etc.

occurred in 1987.[122] [18,19] Figure 20, below, illustrates how little coal-fired capacity and how few units have been retired over the last several years. Utilities retired a total of 2,435 MW of capacity in 1994 for all fuel types, most of which were small old gas-fired units (totaling 1,642 MW) along with 461 MW of coal-fired capacity. [31]

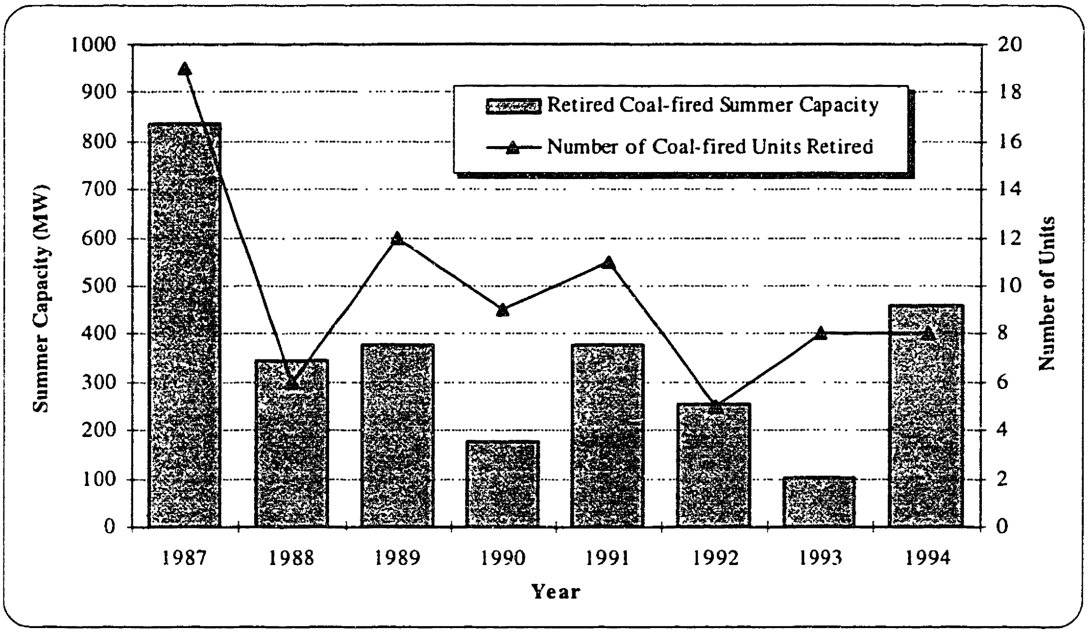

Figure 20: Retirements of Coal-fired Generating Units and Capacity (1987-1994)[123]

In addition to the recent trend of limited retirements of capacity, especially coal, the planned retirements reported by electric utilities through the year 2004 are also quite small (Figure 21). Less than 840 MW of coal-fired capacity is scheduled for retirement by 2004, as reported to NERC by its member utilities. Even less has been reported to DOE's Energy Information Agency.[124] As a consequence, energy analysts are predicting that a large number of units will have to be retired after 2005, totaling potentially 60,000 MW of fossil-fired capacity. Additionally, by 2010, many nuclear plants will potentially be forced to retire, taking with them around 35,000 MW of generating capacity.[125] [62]

[122] Note: 2,931 MW is less than 1% of the 1994 installed coal-fired capacity in the U.S. [31].
[123] Source: DOE/EIA-0348 "Electric Power Annual" (1987-1994) [18,19].
[124] Less than 200 MW of coal-fired capacity has been reported to DOE/EIA as planned for retirement by 2004.
[125] Based on projections by DRI/McGraw Hill's Global Energy Service.

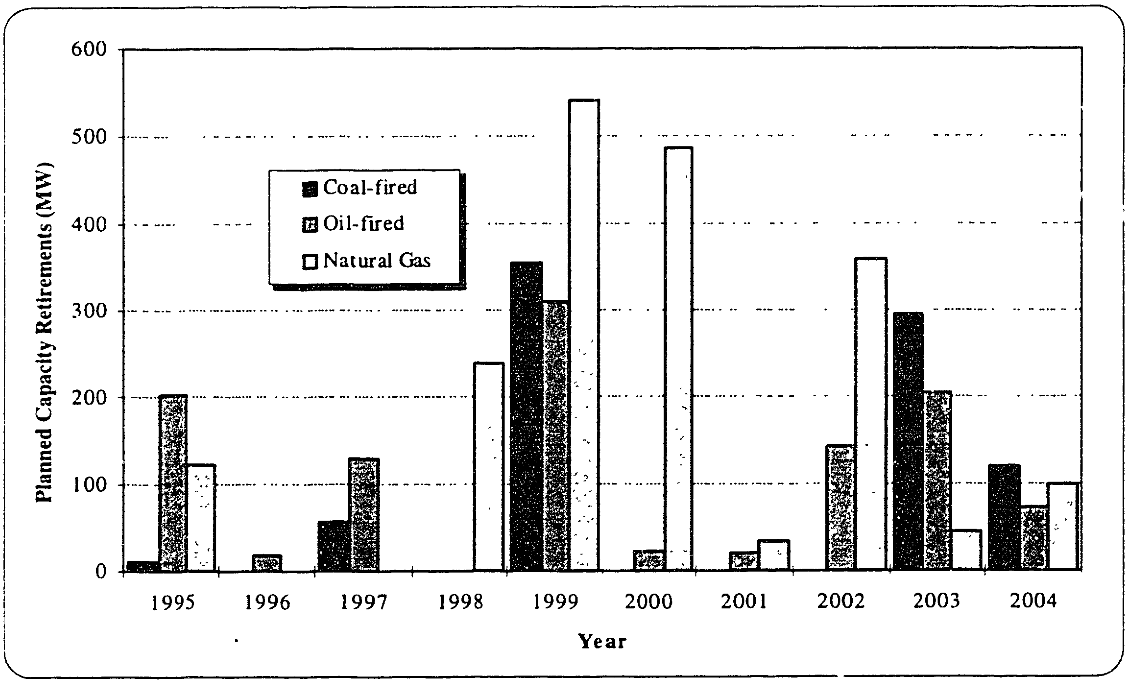

Figure 21: NERC Planned Retirements of Generating Capacity by Fuel Type (1995-2004)[126]

As an alternative to completely retiring aging coal units, utilities are increasingly moth-balling older units, and thereby leaving open the option to bring them back into service at a later time; using them for short-term generation (less than 100 hours a year); and engaging in life extension or repowering modifications. [31] The deregulation of the electric power industry is a primary factor in causing some utilities to maintain older units that would otherwise be retired so that they can be used in the new competitive electricity market. Some of the older coal plants, rescued from retirement, have been labeled as "merchant plants," and are of concern because of the additional NO_x they could generate which had been forecasted to have been eliminated with their retirement. [40]

4.5 Repowering

In many respects, repowering can be seen as the most extreme example of attempting to use existing capital more intensively, in that much of the older equipment is reused in a repowered unit. By repowering aging units, utilities can forestall the need to construct new "greenfield" capacity by extending the useful life of existing facilities. Because of the cost and complications involved in constructing entirely new facilities, there is a growing focus on repowering in the electric power industry. It is resulting from an awareness that much of the current utility generating capacity will be have to be retired in the next two decades, yet electricity demand is likely to continue to grow. Overall,

[126] Source: NERC ES&D database.

repowering deteriorating units can potentially be an advantageous strategy for utilities to address load growth, market competition, uncertainty, and environmental compliance issues. [42]

The cost of repowering, depends upon the particular characteristics of the unit in question, but in many situations it can provide significant capital cost saving versus the construction of a new unit, by reusing existing facilities and steam turbines. It can also avoid some of the political and regulatory problems faced by many utilities and nonutilities when attempting to site new facilities, and often requires shorter construction lead times. [62] In addition, one of the implications of deregulation is that it is expected to create new incentives to repower older units so that they can be used for off-system sales to competitive power pools.

Most repowering of coal-fired units is expected to involve the replacement of an existing boiler with a fluidized-bed combustion process or coal-gasification combustion turbine while the existing steam turbine and other auxiliary equipment is retained. [42] Units of moderate capacity (100-300 MW) are expected to be the focus of the majority of the repowering projects since larger units, in general, already operate with fairly high efficiencies. [42] When a unit is repowered, utilities also have the option of switching to lower sulfur coal or use lower cost high sulfur coal by employing inherently low polluting technologies. Fuel switching and improvements in heat rates through the use of new repowering technologies, is expected to become a favorite method for utilities to meet the Phase II requirements of the CAA's Acid Rain Program in 2000. [62] If a repowered unit can lower its emissions enough, it might even provide additional revenue to its owner through the sale of unused emission allowances. [15] Life extensions, in contrast, add little if any new capacity to a unit, however such modifications can potentially add as much as 20 years of operational life to a plant or generating unit for a lower capital investment. [19]

Due to both the age composition of the existing generating stock and the benefits described above, repowering is predicted to become a significant source of new capacity in the future. The DOE estimates that by 2010, repowering projects could provide as much as 142,000 MW of additional generating capacity. [15] However, despite the expectations and the fact that a few repowering projects have already been undertaken, utilities have scheduled few projects for the near future. Of the roughly 3000 MW of utility capacity that has already been repowered, more than half has involved the addition of a combined-cycle gas-fired combustion turbine and heat recovery steam generator to natural gas units. The low price of natural gas and increased efficiency gains has made this option quite cost effective. [42] Coal-fired units, in contrast, already operate at what are usually efficient base load levels with a low cost fuel, and therefore they present less of an opportunity to produce savings by raising their dispatch order or lowering operating costs. As a consequence, the amount of coal capacity scheduled for repowering or life extending modifications is small, as shown in Figure 22 and Figure 23 below. The values presented in each figure are not consistent, due to the fact that the information sources for each one were different, but regardless, it is clear that utilities are currently hesitant to commit resources to repowering projects. Overall, only slightly more than 1,700 MW of capacity has been reported to DOE as scheduled to undergo repowering by the year 2004, slightly more than 20 percent of which is coal-fired. The uncertainty in a deregulated power market is an important factor causing utilities to be both cautious about retiring older capacity and investing in repowering projects.

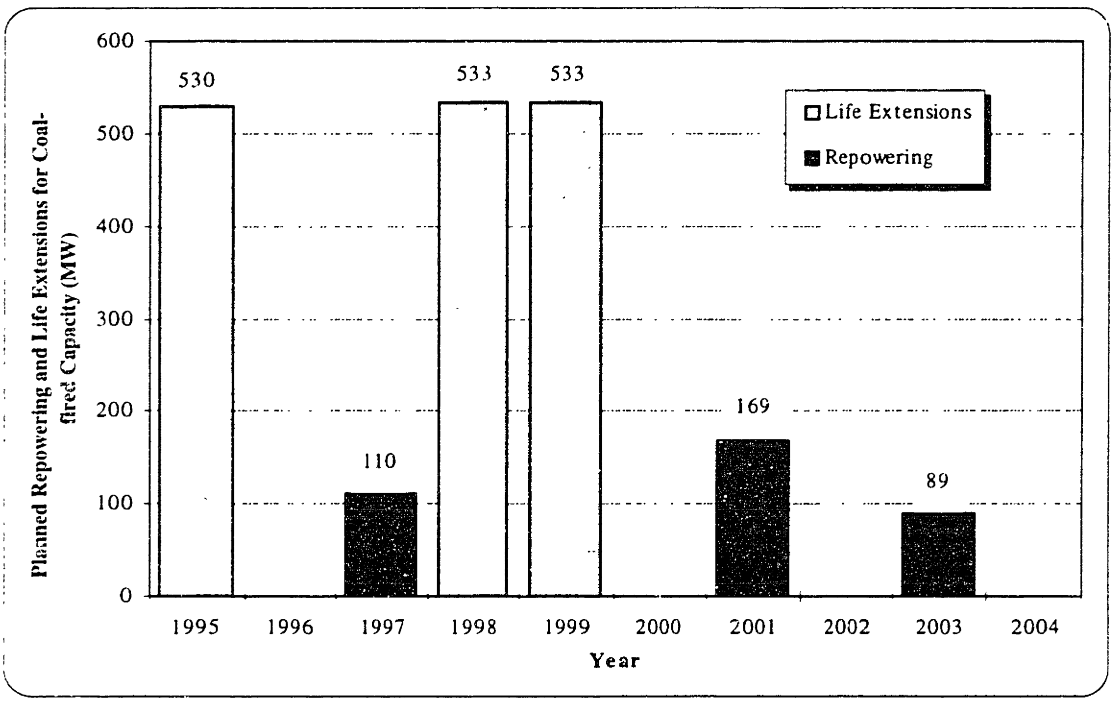

Figure 22: Planned Repowering and Life Extensions for Coal-fired Capacity as Reported to DOE/EIA (1995-2004)[127]

[127] Source of data: DOE/EIA-0094(95), "Inventory of Power Plants in the United States 1994." Note: Data is inconsistent with that in Figure 23.

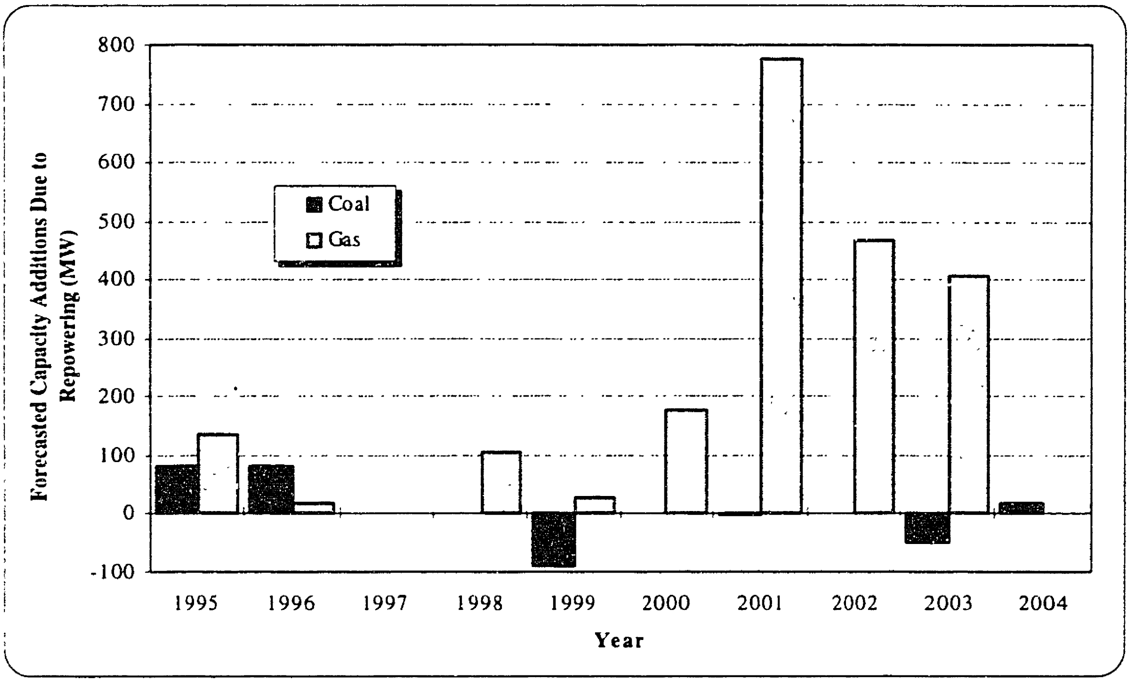

Figure 23: Forecasted Capacity Additions for Coal and Gas Units Due to Repowering as Reported to NERC (1995-2004)[128]

4.6 Unit Additions

Although repowering holds the potential for extending the life and capacity of many existing coal units, continued load growth and eventual deterioration of capital will necessitate that eventually capacity be added to the system. There is a practical limit to how far the average capacity factors for coal or other units can be increased since unforeseen outages, maintenance requirements, and seasonal and diurnal variations in electricity demand will inevitably prevent further increases. These coal-fired units, in addition to nuclear plants, are generally employed as base load capacity because they use a low cost fuel and have some of the lowest operating costs but are not able to rapidly change their output to meet demand fluctuations. Because they operate with high CFs, large capital outlays for a coal unit, relative to the cost of constructing a new gas turbine peaking unit, are justifiable. Inherently, though, investing in a new coal-fired generating unit, as part of a larger power plant facility, is a major capital investment even for a large electric utility, and therefore capacity expansion decisions must take into account multiple economic, regulatory, technological, and market uncertainty issues. Depending upon how each of these issue areas is perceived, they can create incentives or disincentives for utilities

[128] Source of data: NERC ES&D database. Note: Data is inconsistent with that in Figure 22.

or nonutilities to assume the risk of investing in new generating capital and influence their choice of technologies and fuel combinations for that new capital.

The evidence for past and planned coal-fired unit additions strongly suggests that indeed utilities, and to a lesser extent nonutilities, are reluctant to invest in new capacity if it can at all be avoided. As shown above, the strategy being employed to avoid the need for new capacity has been to extract more output from existing units. As introduced in Figure 11 and Figure 12, the reason that coal units are, on average, both aging and operating at higher capacity factors is a result of limited amount of new capacity additions over the last ten or so years, as shown more clearly in Figure 24 below.

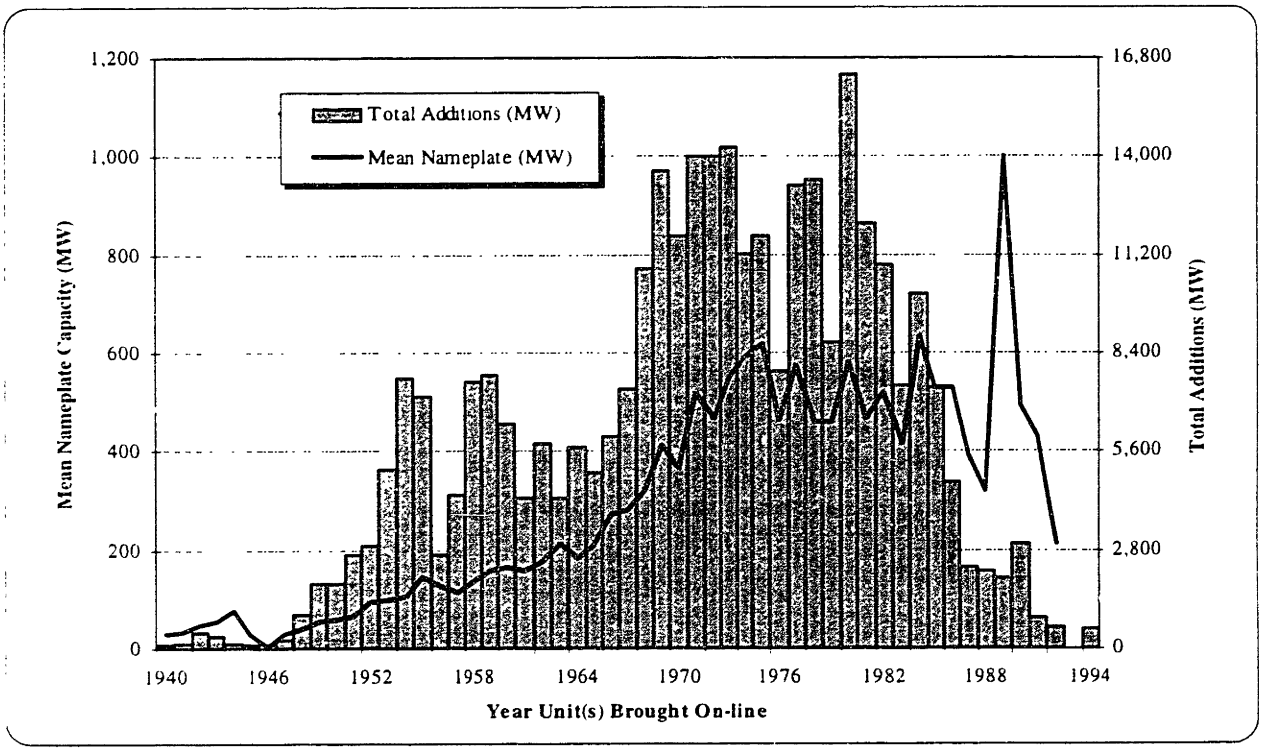

Figure 24: Coal-fired Total and Average (Mean) Nameplate Capacity Additions (1940-1994)[129]

In addition to little new capacity being added, the trend of increasing average capacity of new units brought on-line is apparent, until a capacity of around 500 MW was found to be an economically and technologically efficient size. When larger units were constructed, utilities found, through experience, that unit reliability dropped, and that down-time was more than five times higher for units with capacities above 600 MW than units in the 100 MW range. [56]

[129] Source of data: DOE/EIA. The high average (mean) nameplate capacity seen in 1989 is a result of the addition of two large (1000 MW+) units in that year.

Construction of new coal-fired capacity requires a great deal of planning and lead time to complete the financing, regulatory approvals, and engineering designs necessary. Consequently, the forecasts of new capacity additions are generally accurate over the five to ten years required to complete a unit addition. Construction can be, and often is, delayed, but it is difficult to speed up the planning or construction process in the short-term. Figure 25 presents data on planned coal and gas fired capacity additions through 2004. Coal-fired capacity additions for 1995 through 2004 total 5,386 MW (summer), or 12.6 percent of total additions, with each unit having an average capacity of about 300 MW. Only one nuclear powered unit is scheduled for completion (1,170 MW) over the same time frame; however, 29,042 MW of gas-fired capacity (summer) is scheduled to be added by 2004, or almost 68 percent of the 42,865 MW of total planned additions. Petroleum and hydroelectric units account for the remainder of the total. In 1994 alone, gas-fired units accounted for approximately 80 percent of the 3,976 MW of capacity additions. [31]

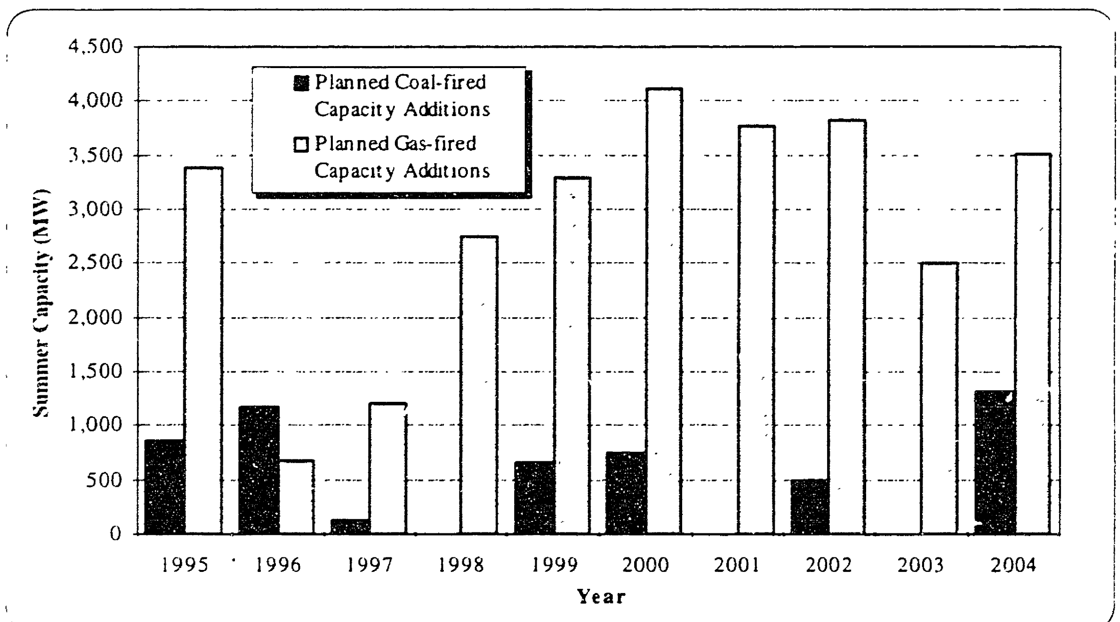

Figure 25: Planned Coal-fired Unit and Capacity Additions (1995-2004)[130]

Although utilities have been hesitant to invest in capacity additions, the amount of nonutility generating capacity has been steadily increasing since the mid 1980's, as shown in Figure 26. Nonutilities with one or more megawatts of installed capacity in the U.S. owned a total of 68,445 MW (nameplate) in 1994, which was equivalent to 9.2 percent of installed utility capacity. Of the electricity

[130] Source of data: "Inventory of Power Plants in the United States 1994," DOE/EIA-0095(94) [31]

generated by nonutilities, slightly more than half came from burning natural gas, while coal accounted for only 16.6 percent of the total. [20] As for the future, nonutilities currently have planned to add 10,014 MW (nameplate) from 1995 through 1997, compared with 13,125 MW of planned additions by utilities during the same period. Of the nonutility additions, coal-fired capacity represents 24.3 percent. [20] The rise of the nonutility generating sector can be seen by the fact that in 1986, utility net additions were about four times larger than nonutilities. [56] The emergence of nonutiltity generators and their growing percentage of total generation is the cause of a good deal of the uncertainty perceived by utilities as to the future of the market. The nonutility issue, and others as they relate to the long-term planning process for changes in generating capacity, are the topic at the following section.

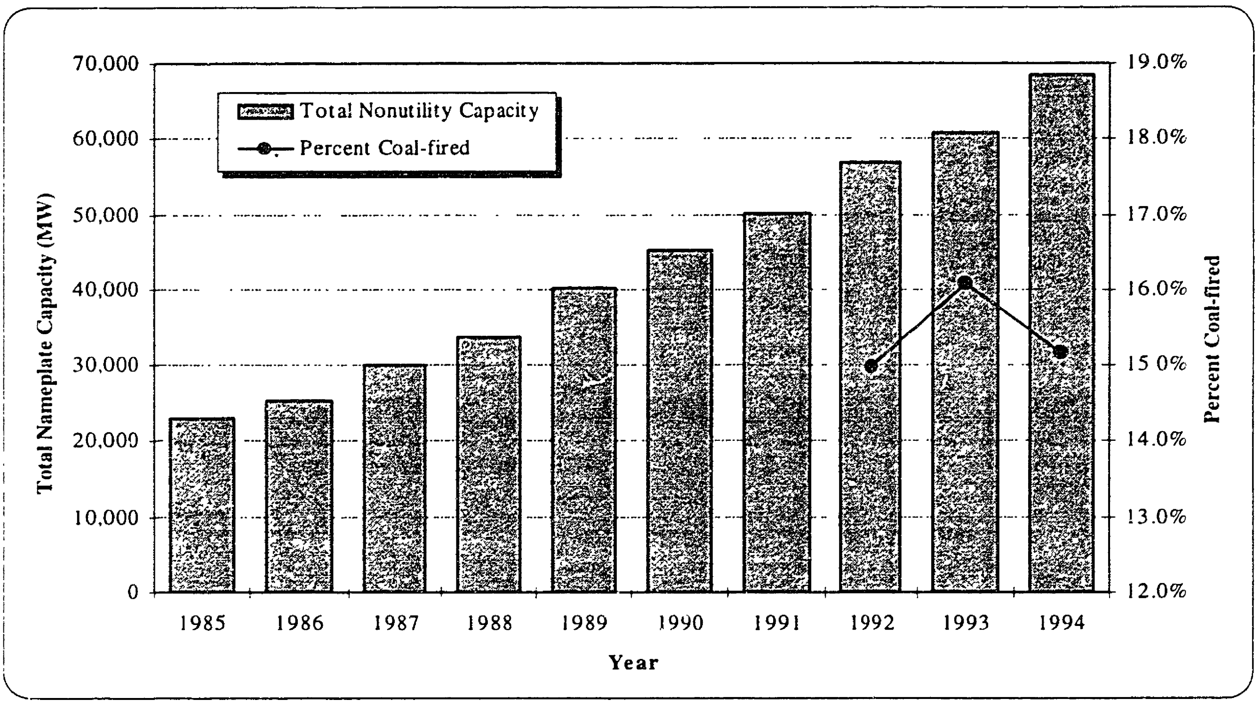

Figure 26: Total Nameplate Capacity and Percent Coal-fired for Nonutility Sector (1985-1994)[131]

4.7 Planning Issues

In the electric power industry, the most obvious variable determining the need for additional capacity is growth in demand. The traditional engineering and economic issues that have been part of utility capacity expansion planning were based upon an assumption that demand growth was

[131] Source of data: 1985-1991 "The Changing Structure of the Electric Power Industry, 1970-1991," DOE/EIA-0562 [56]; 1992-1993 "Electric Power Annual 1993," DOE/EIA-0348(93) [18]; and 1994 "Inventory of Power Plants in the United States 1994," DOE/EIA-0095(94) [31].

predictable and consistent. Utilities, comfortable with their unchallenged monopolies, did not have to take into account many of the factors which are now, in many ways, dominating decision making in the industry. Nonetheless, even though these traditional criteria are no longer sufficient, they are still necessary to address. [31]

- *Technology*: The selection of what technology to be embodied in new capital has most often focused upon the selection of fuel type. For base load plants, the choice has generally been between nuclear, côal, hydro, or in some cases natural gas fired steam turbine units. Some of the new technological options include scrubber systems, efficient gas turbines, combined cycle units, fluidized-bed combustion, and coal gasification.

- *Unit Capacity*: The size of the unit is tied closely to its efficiency because of certain inherent economies of scale; however, larger size units permit less flexibility to changing demand growth and larger loses when failure occurs in a single unit. There is also a certain practical limit to how big a unit can be built before it becomes to complex to construct and operate efficiently.

- *Capital Cost*: The fixed costs of constructing a new base load unit require large outlays of financial capital, and therefore companies that generate electricity must attract investors by offering a rate of return and risk level competitive with the rest of the market. Over time, the cost of constructing a new coal unit has increased as a result of stricter regulation and other factors.[132]

- *Operating and Maintenance (O&M) Costs*: Expenditures on fuel dominate O&M costs for coal units, therefore anything that results in changes in the heat rate or price of coal, especially relative to other fuels, can have a large impact upon total costs. An additional O&M cost for some coal units is the sorbent required to operate flue gas desulfurization systems (scrubbers). As units age and deteriorate, maintenance expenditures would also be expected to rise; however, whether maintenance costs will rise to a level causing aging coal units to be too expensive to operate is uncertain.

- *Heat rate*: Similar to fuel costs, the inherent heat rate of the conversion process determines the amount of electricity that can be generated by a given amount of fuel. More precisely, it is the quantity of fuel that is required to generate one kWh of electricity. Some emission control systems can raise the heat rate by a coal unit by one or two percent.

- *Load Following*: Whether a unit is capable of responding to instantaneous changes in load determines whether it can be employed as peaking or intermediate load capacity, or must be used only as base load. The decision of what type of unit to use for load following purposes must be made on both technological and economic grounds. Again, coal units, because of their cost characteristics and technological limitations, are normally relegated to serving as base load capacity.[133]

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[132] See *Chapter 3 Literature Review* for a discussion of the work on coal unit construction costs by Joskow and Joskow and Rose.

[133] Gasified coal, on the other hand, can be used to run gas turbine units and provide peak load electricity.

- *Reliability*: An additional factor important in selecting not only the technology to be used for a new unit, but also whether an existing unit should be retired, is the equipment's reliability. The cost of unreliable equipment can be measured by the investment necessary to ensure that sufficient backup capacity can be accessed, so that consumer demand can reliably be met, and the extra maintenance expenditures required by the unit.

- *Environmental Performance*: Since the 1970's the cost of environmental compliance has become a significant component of utilities and nonutilities overall cost structure. Consequently, the cost of employing particular technologies or fuels must also be judged on the cost added to meet emission and other pollutant limitations. The cost of burning high sulfur coal faces the added cost of installing more expensive scrubber systems, as is essentially required by the NSPS.

- *Retirements and Deterioration*: Generating units were, for planning purposes, assumed to have a set lifetime in the past, after which they would be retired and new more efficient units would be brought on-line to take their place. Now, however, new technologies are not necessarily any more efficient and face the added burden of having to meet stricter emission limitations.

Other factors, more ambiguous than the ones listed above, are now creating a situation in which there is a great reluctance by utilities to invest in new capacity. Most of these have to do with regulatory incentives and uncertainty in the direction of the industry. Relative to the state of the industry in the past, investing in electric utilities given the current market conditions, and in many cases nonutility generators, is perceived as being both more risky and potentially less profitable. The main factors discouraging retirements and investments in new or repowered capacity include the issues already addressed. Additionally, the SO_2 allowance market created by the Acid Rain Program and the initiation of Phase II in 2000 is leading to increased uncertainty in the future direction of the technologies that will be used for burning coal and the cost of doing so. Although, the price of allowances on the open market has remained unexpectedly low, thereby providing few economic disincentives against operating existing coal-fired units. However, it has made it less profitable for firms to try to increase revenues by selling excess allowances from low polluting units.

Utilities are faced with a multitude of other issues in addition to changing environmental regulations. The regulatory situation facing their market is undergoing fundamental change as deregulation takes place and larger numbers of nonutility generators enter the industry. State Public Utility Commissions (PUCs) have increased the stringency of their rate review processes, causing utilities to become more vulnerable to the losses resulting from imprudent investment decisions. Even when capacity additions are desired, obtaining approval from the public and regulators for an appropriate site can be expensive and in some areas almost politically impossible. Options other than mere expansion must also be considered, including demand side management programs and other conservation efforts to forestall demand growth.

When capacity expansions are decided upon, the data presented in the previous sections suggested a trend associated with these additions in both the utility and nonutility sectors. The trend is that natural gas has been the fuel of choice for most new units constructed since the early 1980's, mostly in the form of gas-fired combustion turbines, whether in the simple or combined cycle configurations. [31] This trend appears to be a consistent predictor of the immediate future. Figure 27 shows the natural gas and coal-fired planned capacity additions by utilities from 1995 through 2004. More than half of all unit additions during this time are scheduled to be gas-fired, again totaling 29,042 MW, and 79 percent of this gas capacity will be in the form of combustion turbines in single or combined cycle configurations. [31] Some of the reasons for this trend include the drop in gas prices, as the gas industry itself has undergone deregulation, and congressional repeal in 1987 of the Power Plant and Industrial Fuel Use Act (PIFUA) of 1978, which eliminated a legal restriction preventing increased use of natural gas by utilities. The technology employed in combustion turbines has also advanced to the point where it is both more reliable and efficient. The combination of a combustion turbine with a steam boiler, in the form of a combined cycle unit, has likewise lead to overall increases in generating efficiencies in the new and repowered units where it has been installed. Gas turbines, themselves, are relatively inexpensive and, because of their small size, are much easier to site than larger coal-fired units. Consequently, they have been a favorite choice of both utilities and nonutilities looking for ways to avoid expensive capital outlays. Lastly, because natural gas has a much lower concentration of impurities, gas-fired units can comply with most environmental regulations at a lower cost than other fossil fuels. Essentially the investment risk of installing several smaller capacity gas turbines is much lower than the risk of investing in a large coal-fired unit, as long as it is not needed to supply large amounts of baseload power. Eventually, though, as large quantities of coal and nuclear capacity are forced to retire, it is questionable whether gas will be a cost effective option to provide a large percentage of the nation's baseload capacity. The DOE in its *Annual Energy Outlook 1996* has predicted that between 2010 and 2015, natural gas prices will rise which, in combination with retirements of nuclear powerplants, will cause demand for the construction for coal-fired baseload capacity to increase. [3] In reality, however, the current climate of change in the industry has generated so much uncertainty, that predictions can be taken as being nothing more than simple speculation. No one is even sure whether the industry will be increasingly dominated by small opportunistic nonutility generators or whether utilities will maintain their dominance.

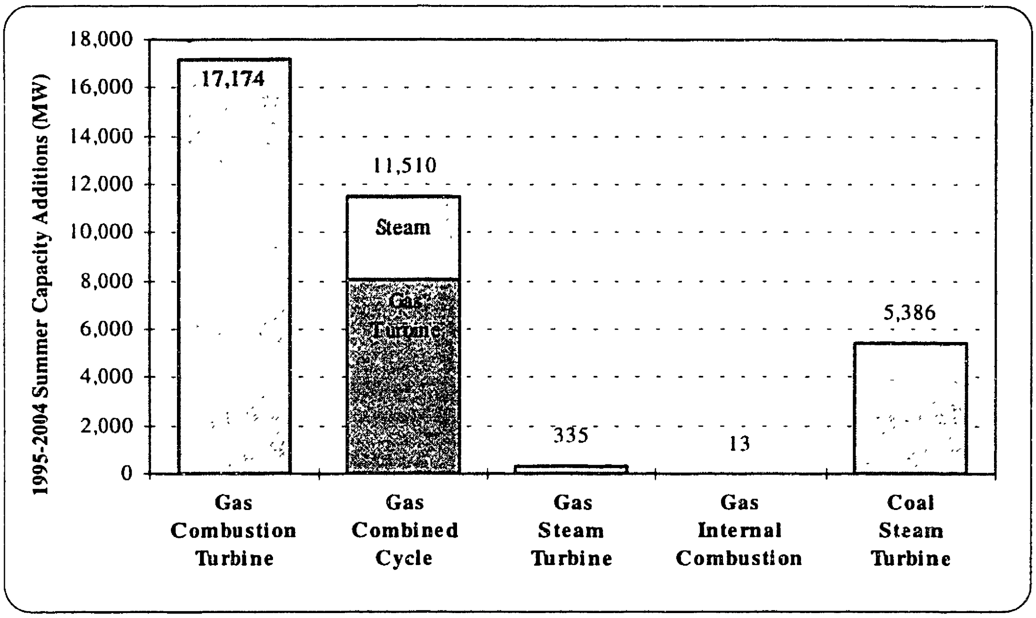

Figure 27: Planned Capacity Additions by Fuel/Technology Type for 1995-2004[134]

[134] Source of data: "Inventory of Power Plants in the United States 1994," DOE/EIA-0095(94) [31]. Values for combined cycle capacity includes both combustion turbine and steam turbine contributions.

Chapter 5 Conclusions

The conventional notions of capital scrappage and replacement used in formulating many environmental regulations are inadequate as can be seen in the increasing reliance of electric utilities on older, more polluting, coal units. Although it may be applicable to some capital items,[135] the notion of a fixed replacement ratio associated with the New Source Performance Standards (NSPS) in the Clean Air Act (CAA) is not a valid assumption for stationary sources that require a significant investment of capital and have long lifetimes. The replacement ratio and deterioration rate for the capital stock of coal-fired generating units in the U.S. is not fixed, as is demonstrated by the changing age and utilization trends in the industry. Clearly replacement decisions are affected by a multitude of financial and regulatory factors.

These trends give evidence for the extent to which changes in the regulatory and competitive landscape of the industry can influence investment, retirement, and utilization decisions, especially by utilities. Utilities, in the past, have had a captive set of customers. From their vantage point, because of rate regulations by Public Utility Commissions (PUCs), they have also faced a fairly inelastic demand. On of the supply side , the two variable categories that firms in the industry can manipulate to control their costs are their investment and operating expenditures. The latter of these two categories, however, is partly predetermined once equipment has been installed. The dispatch order of units can be varied, but once a particular technology has been selected and embodied in the installed capital, then only limited control over operating costs is afforded to managers. Capital investment expenditures, however, can be reduced during times of lower growth and/or heightened uncertainty, or expanded during times when growth is perceived as being rapid and/or predictable. Generating equipment, once installed, not only presents firms with a somewhat fixed operating cost structure but must also remain in service for many years, causing even prudent investment decisions to have serious long-term consequences for a firm's profitability and the natural environment.

The low level of past and planned investments in electricity generating capital seen over the last several years is the result of several factors. First, utilities have emerged from a period marked by costly overcapacity in many regions of the U.S., arising from inaccurate predictions of demand growth during the 1970's and 1980's. As a consequence, instead of investing in new capital, utilities have

[135] Although even for automobiles, such an assumption is probably too simplistic. Recent trends seem to show that consumers are operating and maintaining cars longer.

attempted to lower their reserve margins by letting demand grow to meet their generating potential. Second, demand growth for electricity has slowed, although it is still growing, increasing the risk of over building and being burdened with further overcapacity. Third, the cost of constructing a new plant and installing new generating units began increasing in the 1970's while electricity prices have remained relatively stagnant.[136] Fourth, one of the more important points is that the efficiency improvements embodied in new technologies has decreased dramatically. No longer are new technologies necessarily more efficient or cost reducing than existing capital.[137] Fifth, environmental regulations have imposed some additional costs on utilities and nonutilities depending upon the size, technology, and fuel type of the unit. The CAA and its associated NSPS have placed emission limitations on both new and existing units and have required the installation of expensive pollution control systems for coal-fired units. The added public pressure arising from community Not-In-My-BackYard (NIMBY) responses to new plant construction, has further increased the costs of planning and building new capacity. Sixth, in part because of each the previous five points, but especially because of the investment decisions made by utilities leading up to their period of overcapacity, Public Utility Commissions have increased the stringency of their review processes and have been less willing to allow rate increases for what they have viewed as imprudence.

Each of the above points is relevant; however, some of the more recent trends seen in the evidence presented in the preceding chapters has implied that other factors are also at work. One of the overriding factors has been the uncertainty created by the incremental deregulation of the electric power market, through passage of the Public Utility Regulatory Policies Act of 1978 and the more recent Energy Policy Act of 1992, both of which have led to the increasing prevalence of nonutility generators. Despite the fact that demand for electricity is not expected to stop growing anytime soon, the future of the industry is perceived as being highly uncertain, relative to its status in the past, and therefore capital outlays for new generating equipment are also perceived as being more risky than they were in the past. Utilities have been avoiding long-term financial commitments in order to minimize their risk exposure to market changes. Reduction of capital expenditures is the primary lever that is available to utilities that can be manipulated to control long-term costs, and therefore utilities have avoided making investments because the economic risk of excess capacity is increasingly being placed upon them and not the ratepayers. In the place of new capacity, so that demand can be met, both utilities and nonutilities have been relying on additions of less capital intensive gas turbines, increased

[136] However, the rise in construction prices has probably halted in the 1990's, and may have even decreased somewhat.
[137] Combined cycle units can lead to improvements in efficiency; however, it is difficult to imagine replacing a large percentage of the existing baseload capacity in the U.S. with such natural gas-fired units.

utilization levels of older existing units, and most likely higher expenditures for maintenance on the equipment being utilized more intensively. In addition, the start of the Acid Rain Program's SO_2 allowance trading system has introduced some new costs and uncertainty; however, the extremely low value of these allowances has likely resulted in the program having little influence on utility investment decisions.

One of the obvious results of this trend of low investment has been that the portion of the aggregate stock of capital used for baseload capacity, in the form of coal-fired generating units, is aging. This aging would be expected to have caused deterioration of the overall stock of capital; however, on average coal units are being operated at increased utilization levels, especially in the case of previously less utilized older units. In an industry where capital was assumed to eventually deteriorate to an uneconomically useful state and where demand for electricity has continued to grow, even if slowly, it is doubtful whether capital investments will be able to be postponed indefinitely. Much of the current stock of coal-fired generating capacity in the U.S. will reach an age in the next 10 to 15 years that will almost necessitate that they be replaced or repowered. By the year 2010, 75, 38, and 16 percent of the operable coal capacity in 1994 will be more than 30, 40, and 50 years old, respectively, unless significant additions of new capacity are made (see Figure 28). Additionally, more than 35,000 MW of nuclear powered baseload capacity will have reached the end of its planned lifetime by the year 2015. [62] Unless these nuclear plants are allowed or modified to operate longer or new nuclear plants are constructed, then this other large source of baseload capacity in the U.S. will face drastic contraction.[138]

[138] The added factor of how to dispose of the facilities and wastes associated with the decommissioning of nuclear powerplants will also be a pressing issue, potentially leading to their continued operation, in the future.

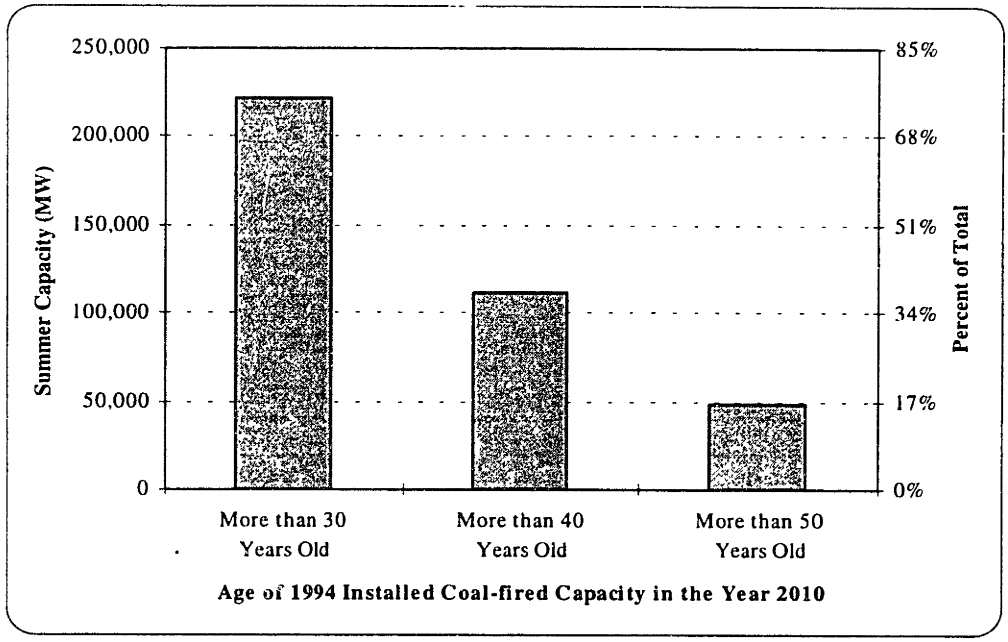

Figure 28: Coal-fired Capacity More Than 30, 40, and 50 Years Old by the Year 2010[139]

An important question for future research implied by these results is whether maintenance expenditures for coal-fired units actually have grown as a result of aging and increased utilization, and if they have, by how much. The answer to these questions would improve predictions as to the future course of the industry in terms of the investment strategies that are likely to dominate and the choices of technologies and fuel sources to expect. It would also be useful to investigate whether older plants truly do result in larger environmental impacts through increased pollutant emissions. With the beginning of Phase II of the Acid Rain Program and its cap on nationwide emissions, it could be argued that SO_2 emissions would be unaffected by increased utilization of older plants. Other pollutant emissions such as NO_x, however, may be increased as older coal-fired units are utilized more intensively in place of new less polluting coal technologies or natural gas fired units.

The evidence presented in earlier chapters has described an industry that is extremely risk averse in terms of capital expansion, replacement, or retirement decisions. The investment risk of constructing new generating units has been shifted onto both utility and nonutility generators and away from retail and industrial customers. Utilities can no longer simply pass the costs of excess capacity onto ratepayers, and nonutilities are less able to obtain long-term contracts at generous wholesale prices. It is questionable, however, as to how long the life of existing coal or nuclear units can be

[139] Source of data: DOE/EIA modified dataset

extended and what role repowering will have in the future composition of U.S. baseload generating capacity. The answer to these questions depends heavily upon the impacts of deregulation on the development of the electricity generating market, which in large part will be guided by the formulation and implementation of regulatory mechanisms.

The forestalling of investments, and therefore the turnover of capital, in the electric power industry has likely had negative environmental implications, as newer less polluting technologies have not been introduced as quickly as might have been expected. However, this trend, if it is assumed that major investments in new or repowered capacity will eventually have to be made, presents policy makers and regulators with an interesting opportunity. The long lived nature of electric generating units means that the technology choices made today will have implications for years to come in terms of the economic and environmental costs imposed upon society from their use. Investment projects in a less regulated market are not going to be predictable, but as has been seen, regulatory mechanisms and changes can have a significant impact on firm decision making. Therefore, when these projects are initiated, the opportunity exists to create incentives for utilities and nonutilities to select and invest in technologies and fuels that will provide a larger net social benefit, in other words technologies or fuels that are both more efficient and less polluting.

As a final note on the environmental implications of continued reliance on fossil fuel sources to generate the bulk of our electricity, a study presented at the August 1995 International Energy Agency (IEA) Conference by A.F. Amor and G.T. Preston titled "The Impact of Fossil Generation Advances on the Emissions of CO_2 in the United States," questioned whether introduction of more efficient fossil fuel technologies would result in lower greenhouse gas emissions. According to their analysis, the application of high efficiency fossil generation technologies would, by the year 2010, potentially prevent the release of 620 million tons of CO_2 per year. However, even with aggressive introduction of such technologies, emissions from fossil-fueled generating plants would still not be reduced back to 1990 levels, as called for in the U.S. Climate Change Action Plan. This optimistic scenario called for the rapid installation of coal and gas fired combined cycle units and the retirement of three-quarters of existing coal plants by the year 2010, yet it still resulted in a 16 percent increase over 1990 levels.[140] So, although less polluting and more efficient technologies will lower CO_2 emissions per unit of capacity compared to continued reliance on current technologies, such changes alone will not be sufficient to address all of the global implications of burning fossil fuel for electricity.

[140] Taken from *Fossil Plant News* Fall 1995 issue, published by the Fossil Power Plants Business Unit, Generation Group, Electric Power Research Institute (EPRI). [http://www.epri.com/org/gg/fospp/news/fall95/warming.html]

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Appendix: Discussion of Data Sources

The purpose of this appendix is to provide a more detailed discussion of the manipulation and composition of the data used to support the arguments in this thesis. It is divided into three sections, described below:

1) The *Data Sources* section adds to the information presented in Chapter 4, Section 1 concerning the origin and treatment of the database of coal-fired generating units in the U.S. Justification for the elimination of particular outliers is also presented.
2) The *Data Composition* section provides some additional information on the overall structure of coal-fired units and coal-fired capacity in the U.S. to assist in interpreting the figures and tables presented in the main body of the thesis.
3) Lastly, the *Capacity Factor Distribution* section explores the distributions which underlie the average (mean) capacity factor values presented in Chapter 4.

Data Sources

As introduced in Chapter 4, three main sources of raw data were relied upon to construct the supporting graphs, tables, and statistics found in this thesis, except where otherwise noted. The North American Reliability Council's (NERC) Electricity Supply & Demand (ES&D) database was used to provide data on future capacity retirements, repowering projects, and forecasts of future demand and capacity growth. The ES&D data, however, is subject to all the restrictions noted in Chapter 4, namely that NERC does not include in its membership all coal units in the U.S. It does encompass the vast majority of coal-fired capacity in the U.S., and therefore provides a valid, and nearly comprehensive, perspective of the entire industry. Of the coal capacity represented by NERC, 6.75% resides in Canada but none in Mexico. Overall, NERC includes 96% of the coal-fired capacity in the U.S. in its membership rolls. For the data taken from the ES&D dataset, though, country specific queries were performed so that only U.S. figures were supplied.

The other source of data provided by NERC was the Generating Availability Data System (GADS), which in its hardcopy form is referred to as the Generating Availability Report (GAR). Unlike the ES&D system, the data in the GAR cannot be segmented by country, and therefore the age and capacity factor figures taken from it are less representative of the U.S. GAR contains aggregate data taken from unit level figures that are summarized on an annual basis for all member units. The main focus of the report is on factors that effect the reliability of generating capacity, but it also contains average age and utilization figures.

By far the most important source of data, however, was obtained from the Department of Energy's (DOE) Energy Information Agency (EIA). A complete database of all coal-fired units operable during the years of 1985 through 1994 was obtained. The fields contained in the original database were as follows:

- Report year
- Utility name
- Plant name
- State
- Unit name

- Unit status
- Service type
- Primary fuel source
- Secondary fuel source
- Heat rate
- Month units was brought on-line
- Year unit was brought on-line
- Planned retirement year
- Nameplate capacity (kW)
- Summer capacity (kW)
- Winter capacity (kW)
- Total annual generation (kWh)

From these variables, also generated were the following two values:

- Age = (Report year) - (Year unit was brought on-line)
- Summer capacity factor = (Total annual generation) / [(summer capacity)·(8766 hours)]

This data was taken mainly from report forms that electric utilities are required to submit annually to EIA including Form EIA-767, "Steam Electric Plant Operation and Design Report" and Form EIA-860, "Annual Electric Generator Report." Statistical manipulation and calculations were performed using a STATA® software package.

Elimination of Data

The complete database obtained from EIA contained 12,707 observations over the ten years, with an average of around 1,270 observations per year. All observations for units that did not burn some form of coal; including anthracite, bituminous coal, subbituminous coal, and lignite; as their primary fuel source were eliminated from the modified database. These observations totaled 277, or around 28 units in each year.

Some units were also reported to EIA with negative annual generation values. Such values are realistic, as some units can be used for load controlling purposes and actually consume power, but such uses are not relevant to the questions that were to be addressed in this thesis, and therefore were eliminated. As can be seen in Figure A 1 below, the percentage of each year's total capacity devoted to these purposes is small, and involved only 150 observations. Over the ten years, the total amount of power consumed by these units or negative generation varied between -6 and -85 GWh.

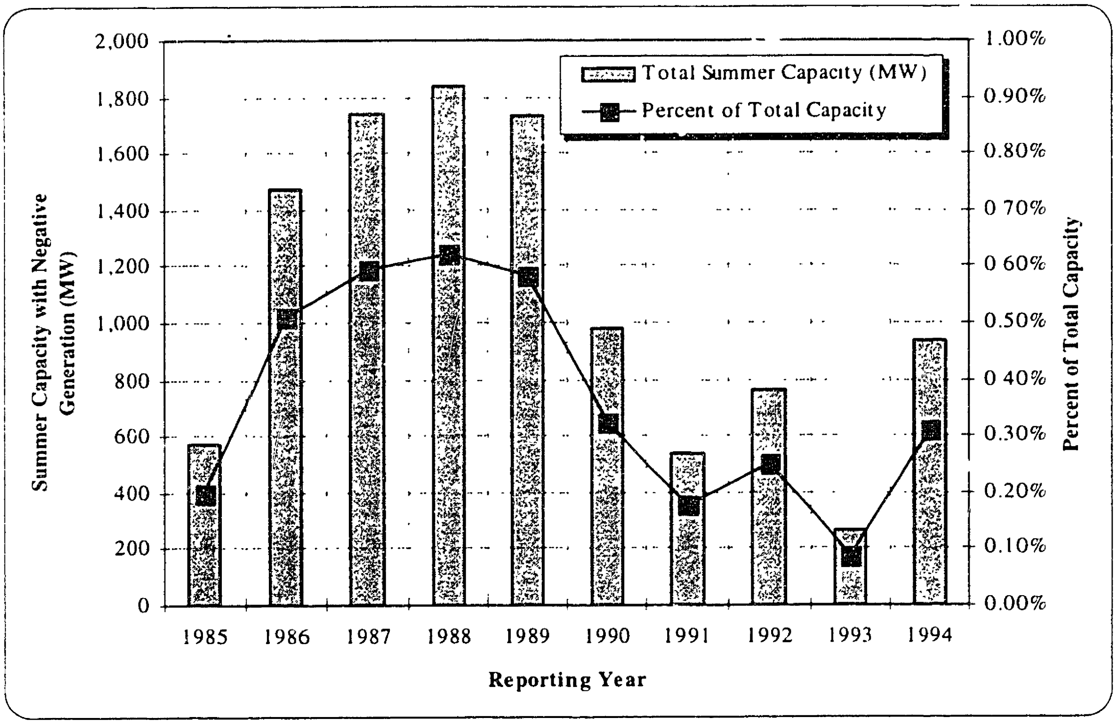

Figure A 1: Capacity and Percent of Total Capacity Operated with Negative Generation (1985-1994)

Some units are configured such that they cannot be assigned individual generation values because they are connected in such a way that the electricity generated from multiple units in a plant is netted together. Some of these units are assigned summer capacities of zero and others for nearly twice the nameplate capacity of a single unit. A total of five powerplants were configured in this way, representing 136 observations, all of which were deleted from the modified database. They include:

- Mississippi Power Company's Jack Watson plant, units 4 and 5
- Mississippi Power Company's Victor J. Daniel Jr. plant, units 1 and 2
- Electric Energy Inc.'s Joppa Steam plant, units 1 through 6
- Provo City Corporation's Provo plant, units 1 through 4
- Basin Electric Power Coop's William J. Neal plant, units 1 and 2

Lastly, 35 observations were eliminated that had summer capacity factor values greater than one (1). A list of these units is given in Table A 1.

Table A 1: Coal-fired Units in EIA Database with Capacity Factor Values Greater Than One

Report Year	Utility Name	Plant Name	Unit Name
1987	Carolina Power & Light Co.	Cape Fear	3
1987	Carolina Power & Light Co.	Cape Fear	4
1988	Colorado-Ute Electric Assn.	Nucla	1
1989	Colorado-Ute Electric Assn.	Nucla	1
1987	Coop Power Assn.	Coal Creek	1
1991	Cooperative Power Assn.	Coal Creek	1
1993	Cooperative Power Assn.	Coal Creek	1
1992	Cooperative Power Assn.	Coal Creek	2
1994	Cooperative Power Assn.	Coal Creek	2
1985	Georgia Power Company	Harllee Branch	1
1991	Kansas Power & Light Co.	Lawrence	4
1993	Midwest Power	George Neal North	1
1988	Ohio Edison Co.	Niles	1
1989	Ohio Edison Co.	Niles	1
1990	Ohio Edison Co.	Niles	1
1991	Ohio Edison Co.	Niles	1
1993	Ohio Edison Co.	Niles	1
1987	Ohio Edison Co.	Niles	2
1988	Ohio Edison Co.	Niles	2
1989	Ohio Edison Co.	Niles	2
1991	Ohio Edison Co.	Niles	2
1992	Ohio Edison Co.	Niles	2
1993	Ohio Edison Co.	Niles	2
1994	Ohio Edison Co.	Niles	2
1992	Ohio Power Co.	Kammer	1
1991	Pacificorp	Dave Johnston	1
1993	Pacificorp	Wyodak	1
1991	Pacificorp	Dave Johnston	2
1985	Pennsylvania Electric Co.	Front Street	2
1987	Pennsylvania Electric Co.	Front Street	2
1988	Pennsylvania Electric Co.	Front Street	2
1989	Pennsylvania Electric Co.	Front Street	2
1990	Pennsylvania Electric Co.	Front Street	2
1994	Tri-State G&T Assoc. Inc.	Nucla	ST4
1987	Virginia Electric & Power Co.	Possum Point	3

The following three graphs summarize the total primary coal-fired generation and capacity not included in the modified database because of elimination of the observations described above. Essentially, no more than 2% of the total generation or total capacity was eliminated in constructing the modified database. Table A 2 shows the number and percentage of actual unit observations eliminated for each reporting year.

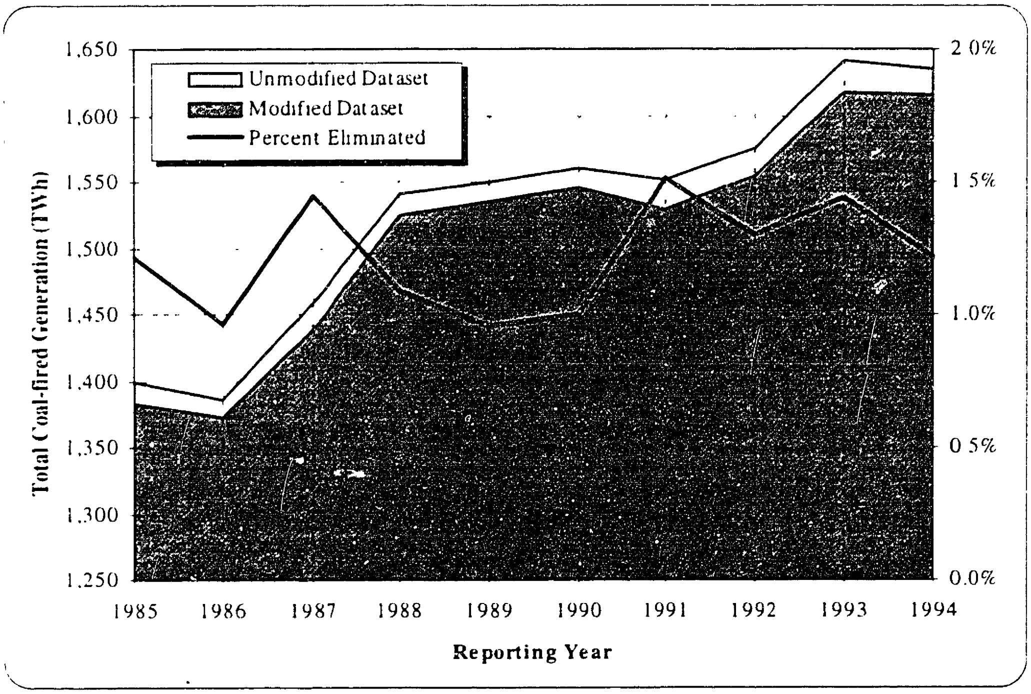

Figure A 2: Total Generation for Modified and Unmodified Datasets (1985-1994)

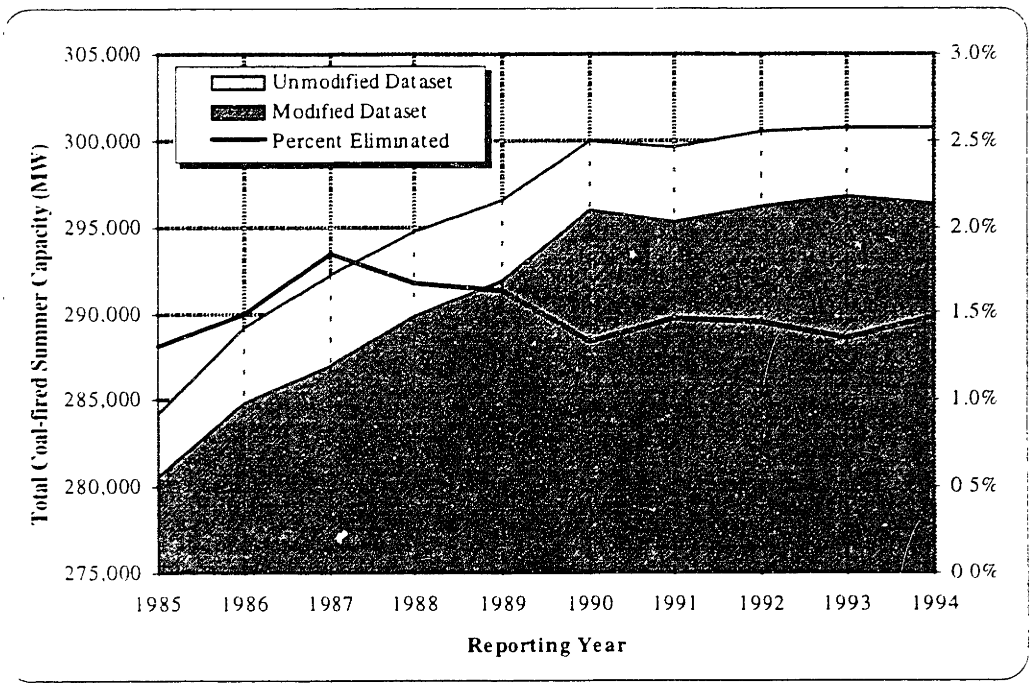

Figure A 3: Total Coal-fired Summer Capacity for Modified and Unmodified Datasets (1985-1994)

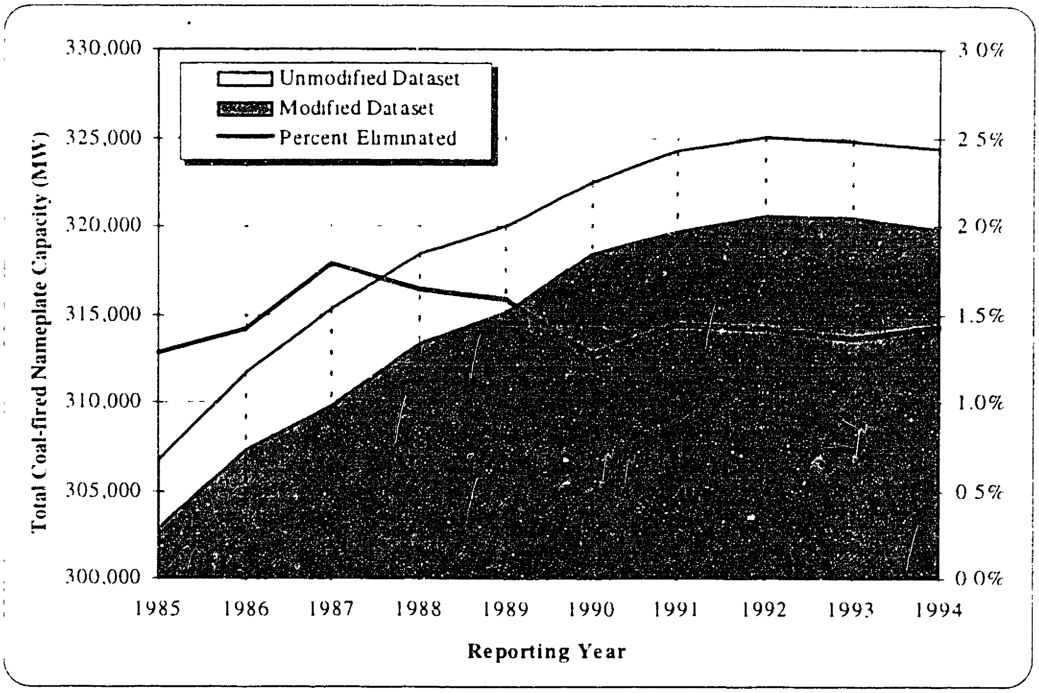

Figure A 4: Total Coal-fired Nameplate Capacity for Modified and Unmodified Datasets (1985-1994)

Table A 2: Number and Percentage of Primary Coal-fired Unit Observations Eliminated

Reporting Year	Number of Primary Coal-fired Unit Observations Eliminated	Percentage of Primary Coal-fired Total Observations
1985	35	2.8%
1986	35	2.8%
1987	43	3.4%
1988	41	3.2%
1989	38	3.0%
1990	30	2.4%
1991	29	2.3%
1992	27	2.2%
1993	21	1.7%
1994	22	1.8%

Data Composition

This section is intended to present some additional information on the composition of generating units that make up the total stock of coal-fired capacity in the U.S. Figure A 5 shows the size distribution of units for each of the ten reporting years that data was available from the EIA. As can be seen, there are a large number of very small capacity units. In Table A 3 the number of units in the modified database using different types of coal are also listed, and finally, in Table A 4 is collected the total amount of summer generating capacity represented by each cell in the unit age/reporting year matrix table presented in Chapter 4

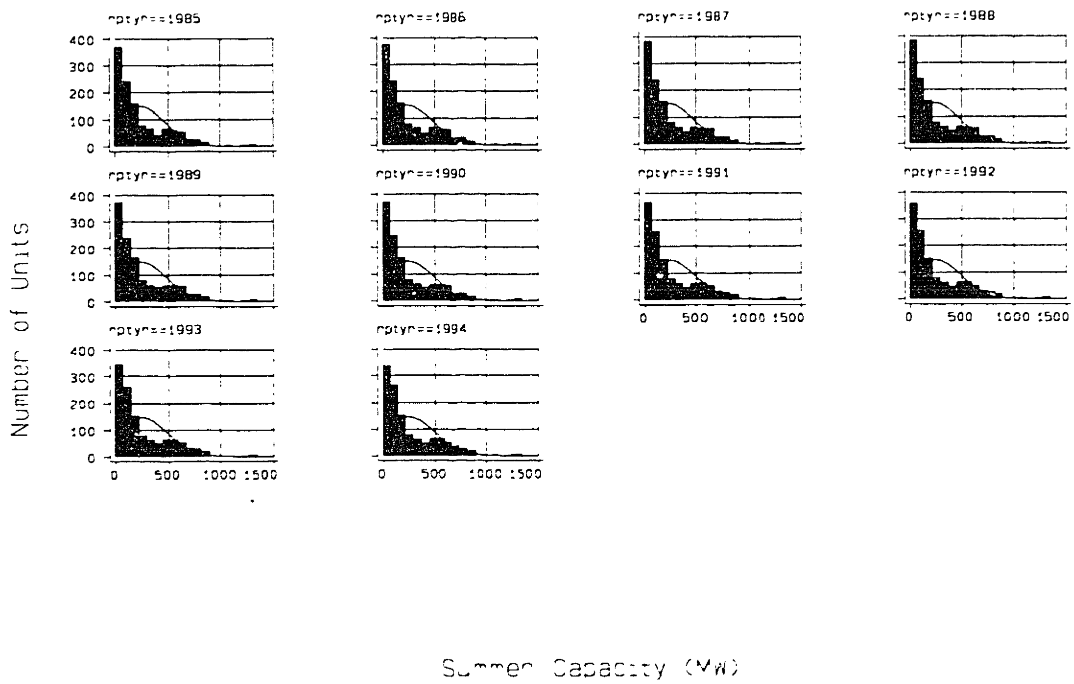

Figure A 5: Distribution of Coal-fired Units by Summer Capacity and Reporting Year (1985-1994)

Table A 3: Number of Observations in Modified Database by Fuel Type

Fuel Type	Number of Observations
Anthracite	40
Bituminous	10,209
Subbituminous	1,549
Lignite	311
Coal (general)	3

Table A 4: Total Summer Capacity Values by Age and Reporting Year (1985-1994)

	Total Summer Capacity (MW)										
Age	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**Average**
1	10,432	6,468	4,864	2,307	1,877	1,972	3,066	790	524		3,589
2	6,119	9,421	6,459	4,905	2,288	1,885	1,972	3,069	794	601	3,751
3	9,337	6,575	9,450	6,455	4,904	2,298	2,072	1,974	3,069	794	4,693
4	11,289	9,334	6,518	9,464	6,469	4,480	2,309	2,073	1,974	2,708	5,662
5	15,732	11,840	8,900	6,569	9,481	6,892	4,491	2,300	2,073	1,972	7,025
6	8,436	15,233	12,307	8,898	6,611	9,486	6,909	4,489	2,300	2,076	7,674
7	10,872	8,001	15,225	12,380	8,943	6,763	9,502	6,911	4,465	2,254	8,532
8	10,935	12,214	7,516	15,222	12,374	10,256	6,814	9,497	6,931	4,483	9,624
9	8,911	10,657	12,003	8,008	15,221	10,983	10,256	6,797	9,492	6,929	9,926
10	10,786	8,139	10,669	11,966	8,018	15,246	11,055	10,269	6,840	9,504	10,249
11	10,548	10,998	8,132	10,669	12,175	8,017	15,299	10,593	10,277	6,869	10,358
12	12,431	10,955	10,957	8,118	10,679	12,149	7,653	15,285	11,080	10,275	10,958
13	13,490	12,096	10,974	10,991	8,121	11,693	12,169	8,122	15,330	10,611	11,360
14	13,139	12,863	12,069	10,970	10,958	7,244	11,716	12,204	7,669	15,365	11,420
15	10,017	12,967	12,869	12,069	10,979	11,003	7,257	11,744	11,975	8,145	10,902
16	13,014	10,811	12,980	12,876	12,156	10,496	10,990	7,284	11,772	11,541	11,392
17	8,941	12,286	10,814	12,952	12,880	12,652	10,497	11,044	7,282	11,754	11,110
18	7,114	9,728	12,512	10,749	12,941	12,870	12,647	10,537	11,084	7,283	10,746
19	4,581	7,161	9,730	12,524	10,751	12,993	12,857	12,655	10,537	11,071	10,486
20	4,701	4,584	7,387	9,710	12,556	10,792	13,024	12,880	12,667	10,512	9,881
21	6,259	4,931	4,777	7,539	9,697	12,565	10,266	13,061	12,906	12,640	9,464
22	3,893	6,277	4,954	4,772	7,558	9,709	12,569	10,822	13,092	12,882	8,653
23	4,888	3,897	6,225	4,972	4,707	6,660	9,749	12,539	10,797	13,060	7,749
24	3,978	4,934	3,889	6,230	5,053	5,591	6,644	9,723	12,525	10,882	6,945
25	6,586	3,981	4,914	3,867	6,221	4,559	5,569	6,633	9,727	12,520	6,458
26	6,063	6,291	4,058	4,912	3,874	5,356	4,565	5,565	6,653	9,714	5,705
27	6,323	6,054	6,231	4,062	4,918	3,874	5,321	4,562	5,575	6,660	5,358
28	4,017	6,561	6,289	6,245	4,054	5,411	3,860	5,286	4,593	5,584	5,190
29	2,511	3,617	6,554	6,297	6,252	3,971	5,398	3,866	5,218	4,593	4,828
30	6,641	2,358	3,621	6,709	6,304	6,247	3,978	5,404	3,863	5,352	5,048
31	6,043	6,387	2,448	3,627	6,438	7,019	5,948	3,979	5,403	3,861	5,115
32	4,328	6,235	6,299	2,295	3,786	6,909	6,923	6,221	4,010	5,383	5,239
33	2,883	4,203	6,091	6,449	2,433	3,994	6,756	6,915	6,213	4,005	4,994
34	2,717	2,898	4,329	6,110	6,446	2,432	3,945	6,439	6,894	5,916	4,813
35	1,850	2,718	2,747	4,268	6,064	6,438	2,372	3,953	6,878	6,895	4,418
36	1,838	1,771	2,634	2,823	4,184	6,282	6,296	2,381	3,964	6,862	3,904
37	906	1,730	1,800	2,616	2,756	4,153	6,192	6,205	2,383	3,936	3,268
38	306	814	1,798	1,720	2,477	2,719	4,189	6,335	6,203	2,365	2,893
39	9	306	852	1,812	1,743	2,644	2,594	4,262	6,318	6,231	2,677
40	112	9	304	834	1,805	1,726	2,626	2,581	4,225	6,327	2,055
41	154	112	9	304	814	1,833	1,647	2,629	2,586	4,268	1,436
42	491	317	112	9	306	778	1,813	1,627	2,588	2,658	1,070
43	458	374	318	112	9	288	831	1,597	1,652	2,611	825
44	154	410	366	317	112	9	296	828	1,697	1,624	581
45	69	82	377	391	256	114	9	296	812	1,665	407
46	49	69	82	413	350	252	114	9	291	814	244
47	28	46	69	142	413	350	146	114	9	244	156
48	29	28	46	69	140	411	397	146	113	9	139
49	3	29	51	46	44	140	412	397	146	115	138
50	63	3	29	50	42	66	128	412	408	146	135
51		63	3	29	50	40	68	127	414	375	130

52	8		59	3	4	50	43	68	79	360	75
53		8		64	2	4	25	43	122	153	53
54			8		69		4	25	35	121	44
55	38			8		69		4	26		29
56	13	38			8		69		4	26	26
57		13	38			8		69		4	26
58	15		13	38			8		85		32
59		15		13	38			8		85	32
60			15		13	38	25		8		20
61	45			15		13	38	25		8	24
62		40	16		15		58	38	25		32
63	1	5	24	16		15		13	38	25	17
64	8	1	5	24	16				13	38	15
65			1	5	8	16				13	9
66			8	1	5	8	16				8
67				8	1	5	8	16			8
68					8		5	8	16		9
69		8				8		5	8	16	9
70							8		5	8	7
71								8		5	7
72									3		3
73										3	3
	1985	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	

Capacity Factor Distribution

In this section, some of the issues involved in the calculation of average (mean) capacity factor values and their use as measure for evaluating changing utilization trends in the industry is examined. The main issue is the presence of unutilized unit observations, or in other words, units with capacity factor values of zero. The overall distribution of unit capacity factor values by reporting year is given below in Figure A 6, which shows the large number of unutilized units that were present in each reporting year. When units were weighted by their summer capacity, as in Figure A 7, the amount of influence of these unutilized units was, however, greatly diminished. This property of the data is why the capacity factor values used in the analysis given in the main body of the thesis relyed upon such weighted measures. To further depict the irregular distribution of capacity factor values, a normal plot is given in Figure A 8. This figure shows how the majority of the units operate at moderate capacity factors of around 0.5 to 0.6, but that a significant number are never utilized.

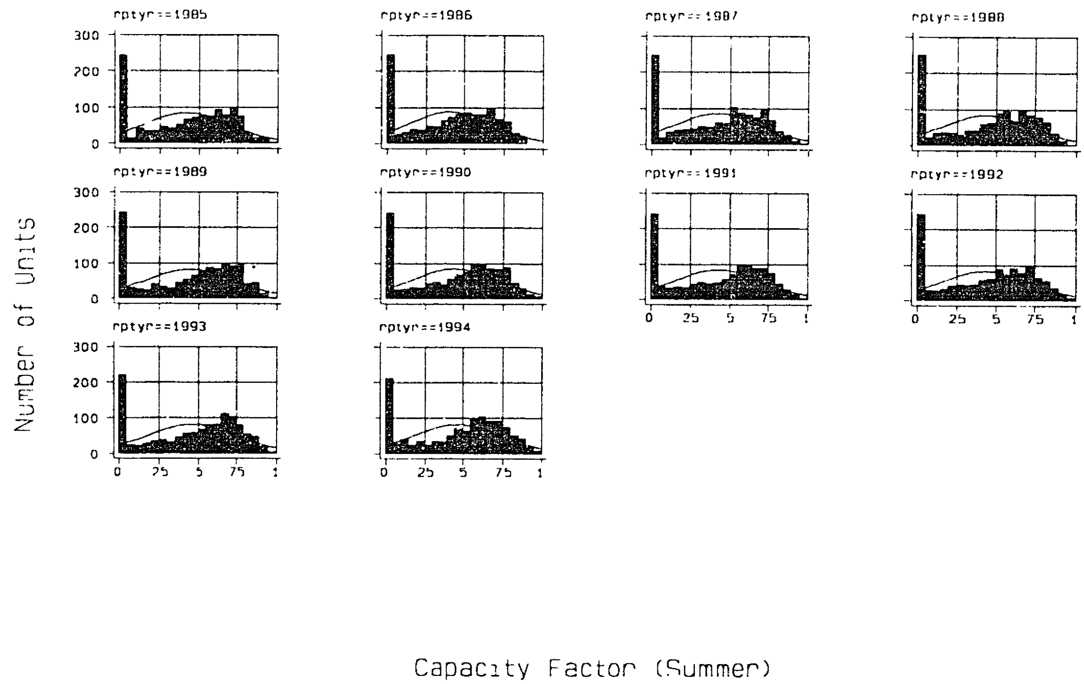

Figure A 6: Capacity Factor Distribution of Coal-fired Units by Reporting Year (1985-1994)

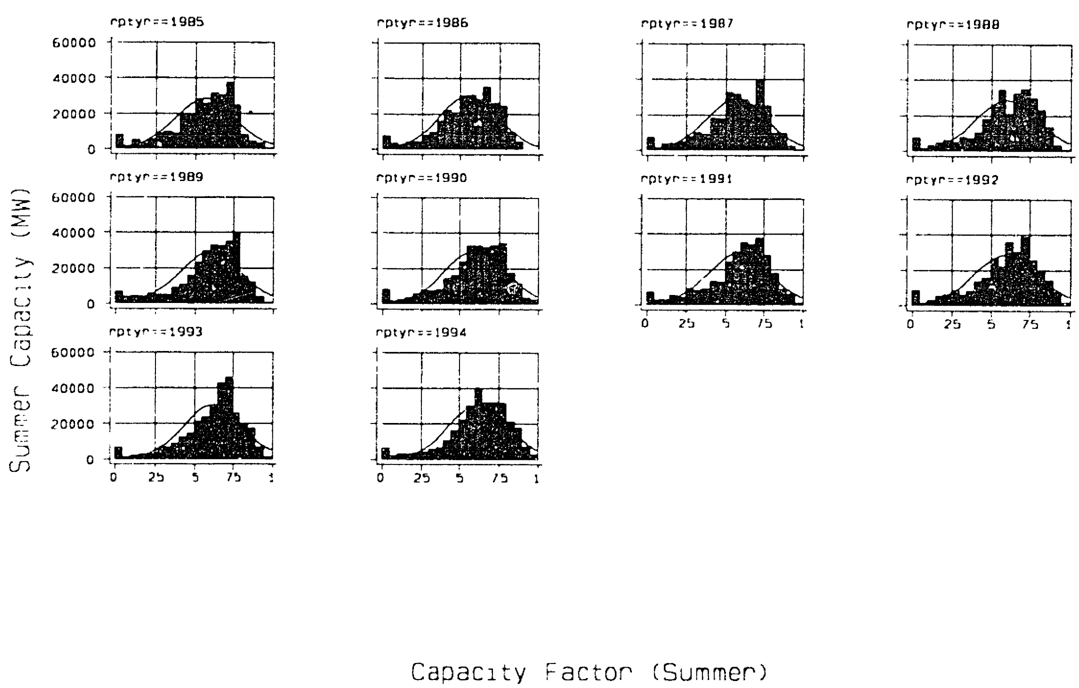

Figure A 7: Capacity Factor Distribution of Coal-fired Capacity by Reporting Year (1985-1994)

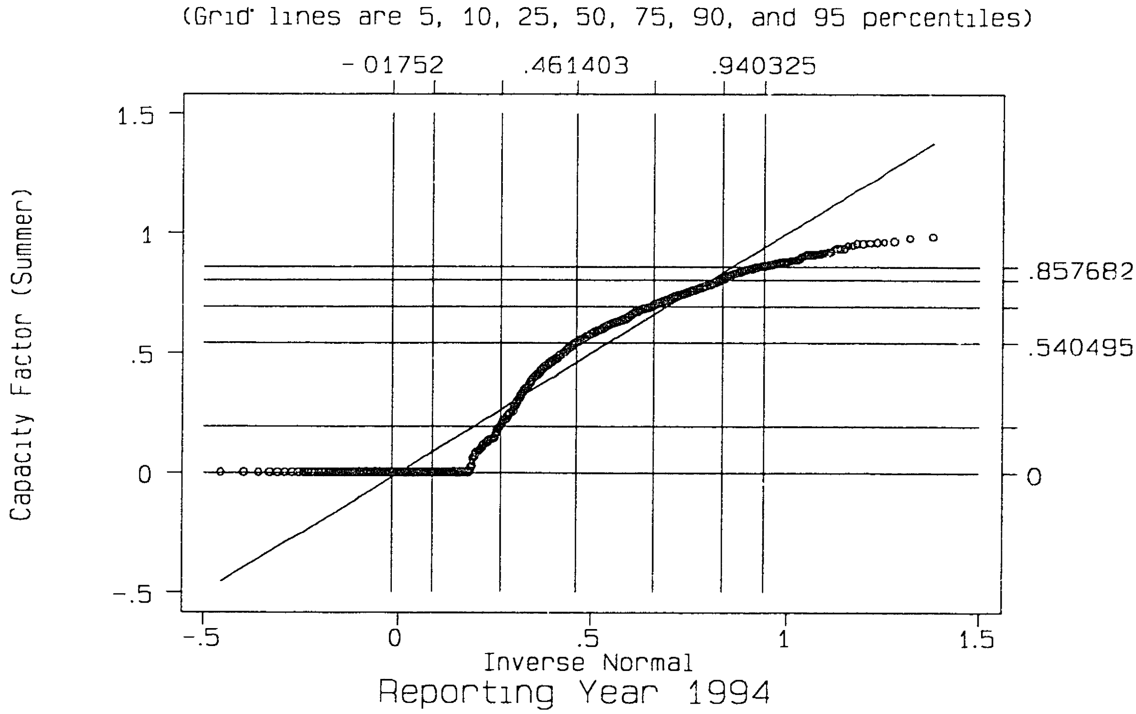

Figure A 8: Normal Plot of Capacity Factor Values for Reporting Year 1994

The amount of capacity that these unutilized units represent each year is, again, small. In general, these are not large capacity units, although they do represent a significant percentage of the total number of units (see Figure A 9 and Figure A 10). Also, the age distribution of these units (see Figure A 11) does not significantly change over the ten reporting years.

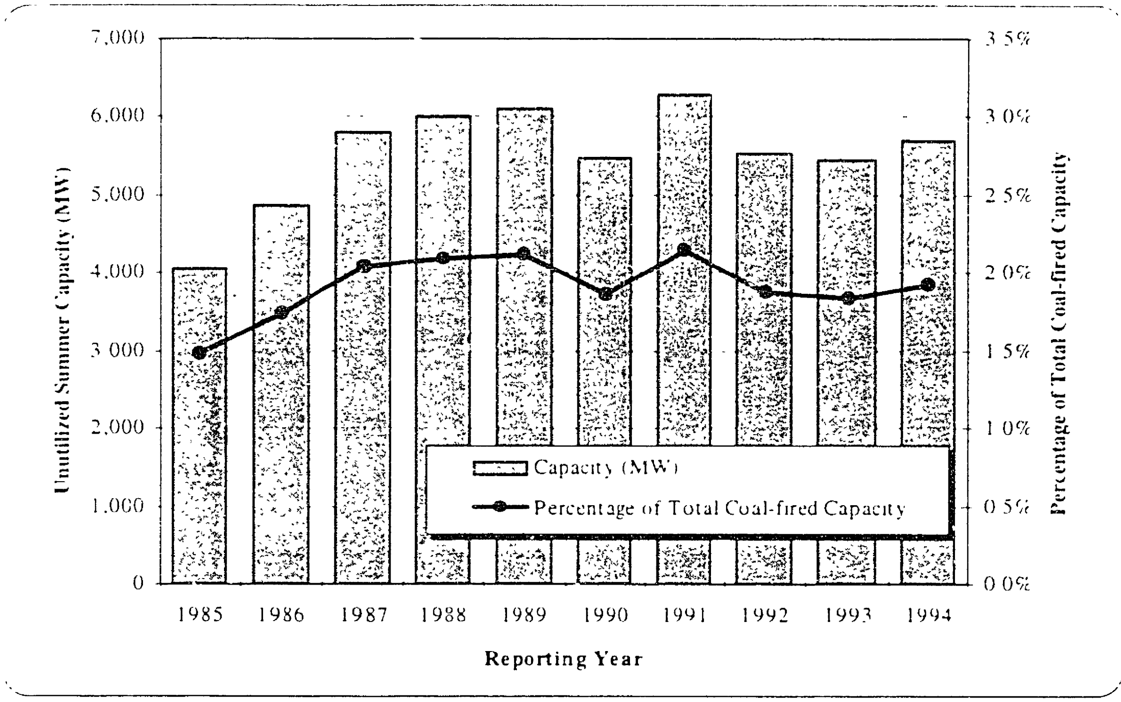

Figure A 9: Aggregate and Percentage of Capacity Not Utilized (1985-1994)

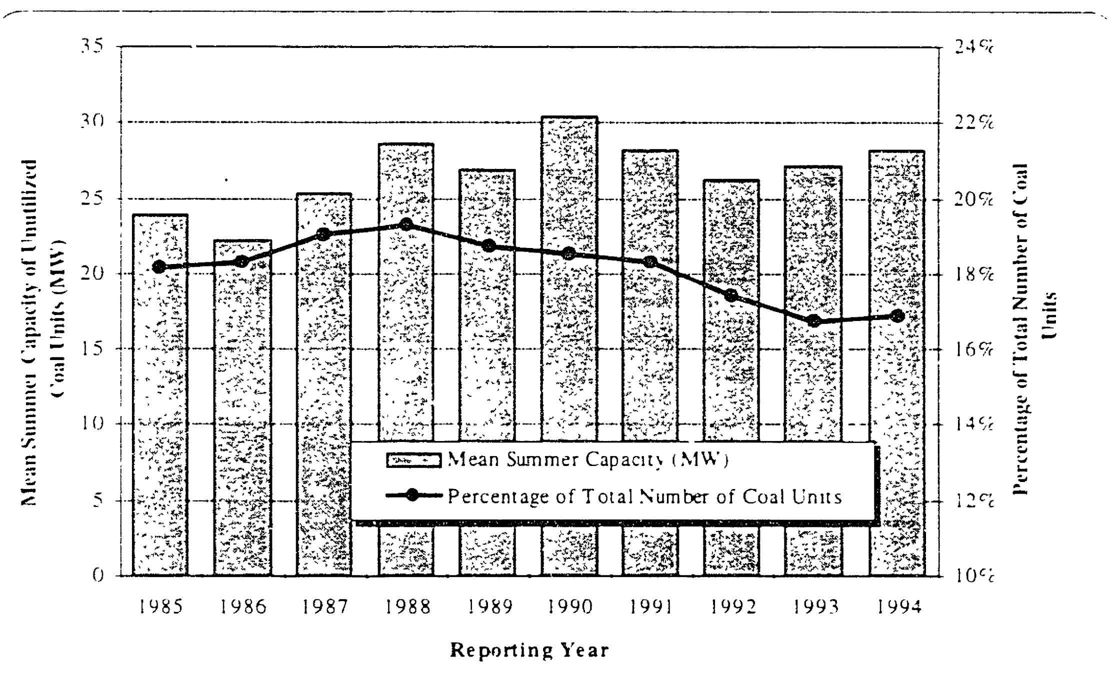

Figure A 10: Mean Capacity of Unutilized Units and Percentage of Total Number of Units (1985-1994)

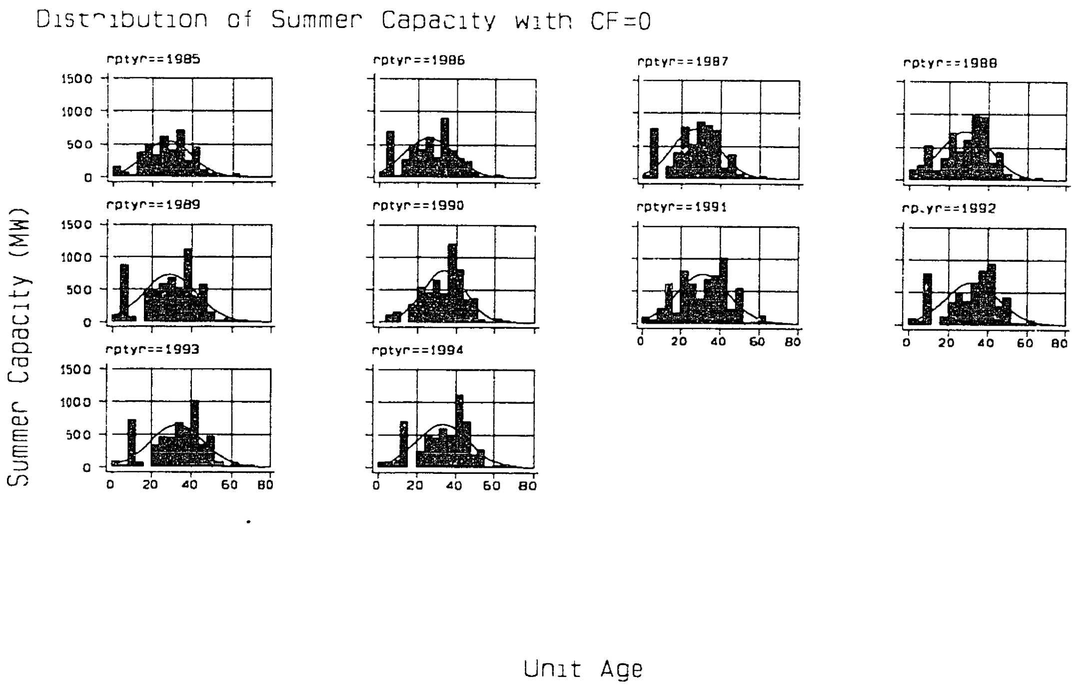

Figure A 11: Age Distribution of Capacity with a Capacity Factor of Zero by Reporting Year (1985-1994)

Analogous to the information presented in Table A 4, below in Table A 5 are listed the total amount of unutilized capacity included in each cell of the unit age/reporting year matrix table in Chapter 4.

Table A 5: Total Unutilized Summer Capacity by Age and Reporting Year (1985-1994)

	Summer Capacity with a CF of Zero (MW)									
Age	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**
1	0	19	32	101	0	0	92	0	4	0
2	63	0	19	32	67	0	0	92	0	81
3	96	63	0	19	32	1	0	0	92	0
4	72	96	63	0	19	32	1	0	0	92
5	0	72	96	63	0	19	32	1	0	0
6	0	530	72	91	58	0	19	32	1	0
7	0	0	530	72	788	58	0	19	32	1
8	0	0	0	530	72	91	64	0	19	32
9	0	0	0	0	0	72	91	64	0	19
10	28	0	0	0	0	0	72	641	64	0
11	0	28	0	0	0	0	0	72	641	64
12	115	0	28	0	0	0	610	0	72	641
13	42	115	0	28	0	0	0	0	0	72
14	132	42	115	0	0	0	0	0	0	0
15	79	108	42	115	0	0	0	0	0	0
16	103	79	108	42	116	0	0	0	0	0
17	105	103	79	108	42	110	0	0	0	0
18	189	105	102	79	243	42	117	0	0	0
19	65	208	105	102	79	108	42	117	0	0
20	167	65	208	105	109	114	466	42	110	0
21	82	127	65	208	107	109	114	110	42	110
22	17	210	127	65	208	107	109	91	96	42
23	62	17	389	337	65	207	107	109	91	96
24	129	62	17	210	239	65	207	107	109	114
25	127	89	281	17	210	166	65	187	107	109
26	263	138	89	115	19	210	126	57	187	92
27	100	319	138	92	115	19	210	124	57	187
28	23	148	319	138	120	60	73	209	164	57
29	56	23	321	309	131	120	60	20	210	166
30	72	56	23	144	281	170	81	60	20	210
31	251	72	199	23	144	292	170	81	60	20
32	293	320	72	184	28	144	293	158	116	51
33	93	292	360	177	184	51	144	293	137	116
34	168	93	292	340	72	184	52	145	270	158
35	151	190	93	297	233	70	184	51	145	270
36	73	173	188	170	307	329	71	184	92	145
37	150	73	248	356	95	299	269	72	184	88
38	8	150	148	248	482	95	299	268	72	184
39	9	8	150	183	226	475	95	299	240	71
40	112	9	12	132	175	261	477	91	300	240
41	36	112	9	12	124	217	181	478	91	265
42	134	36	112	9	95	232	193	181	439	91
43	163	134	36	112	9	95	162	193	181	511
44	39	163	90	36	112	9	95	162	188	179
45	29	39	202	109	36	114	9	12	140	377
46	16	29	39	235	192	32	114	9	12	137
47	28	13	29	39	235	192	0	114	9	12

48	29	28	13	29	98	235	192	0	113	9
49	3	29	28	13	4	98	235	109	0	115
50	14	3	29	28	9	26	85	235	109	0
51	0	14	3	29	28	7	26	85	235	76
52	8	0	14	3	4	28	8	26	37	202
53	0	8	0	14	2	4	3	0	42	37
54	0	0	8	0	14	0	4	3	0	45
55	5	0	0	8	0	14	0	4	3	0
56	13	5	0	0	8	0	14	0	4	3
57	0	13	5	0	0	8	0	14	0	4
58	0	0	13	38	0	0	8	0	5	0
59	0	0	0	13	38	0	0	8	0	5
60	0	0	0	0	13	38	25	0	8	0
61	45	0	0	0	0	13	38	25	0	8
62	0	40	16	0	0	0	58	38	25	0
63	1	5	24	16	0	0	0	13	38	25
64	8	1	5	24	16	0	0	0	13	38
65			1	5	8	16	0	0	0	13
66			8	1	5	8	16	0	0	0
67				8	1	5	8	16	0	0
68					8	0	5	8	16	0
69						8	0	5	8	16
70							8	0	5	8
71								8	0	5
72									3	0
73										3

The final six figures are a sampling of the underlying distributions of individual unit and capacity-weighted capacity factor values for selected age and reporting years. Figure A 12, Figure A 14, and Figure A 16 present the unweighted, individual unit capacity factor distributions for units of ages 10, 20, and 30 years. Likewise, Figure A 13, Figure A 15, and Figure A 17 present the same capacity factor distributions, but weighted by the summer capacity of each unit. The variance of these distributions vary due to the uneven apportioning of units and total capacities at each age and reporting year combination. Overall, however, average values are a valuable measure to assess utilization trends in the industry.

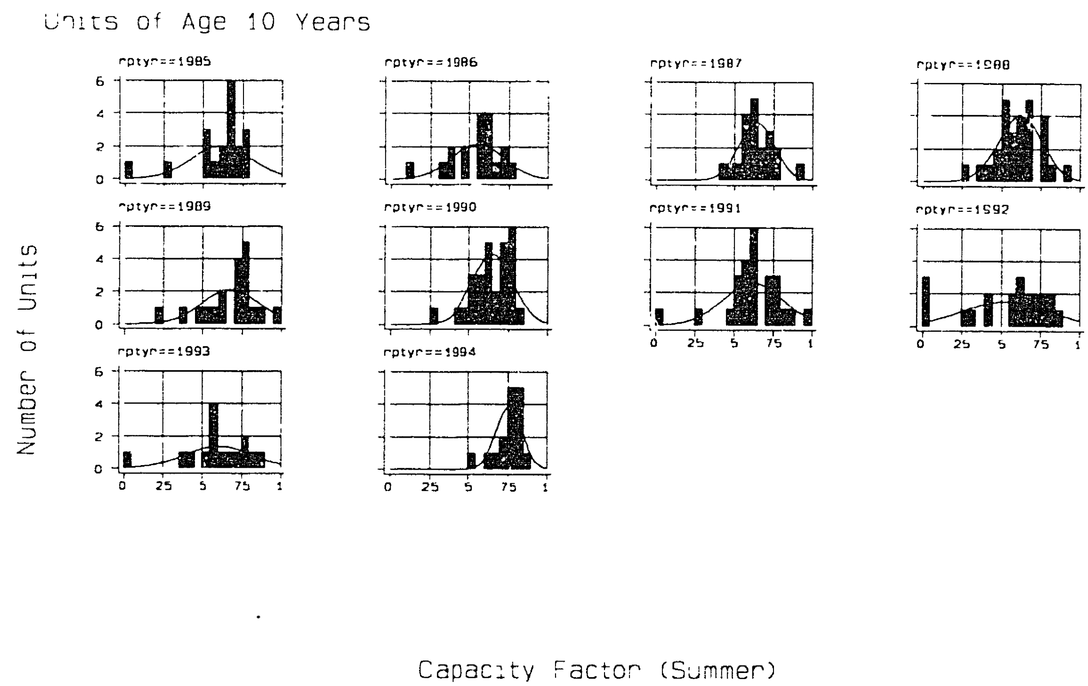

Figure A 12: Distribution of Capacity Factor Values for 10 Year Old Coal-fired Units by Reporting Year (1985-1994)

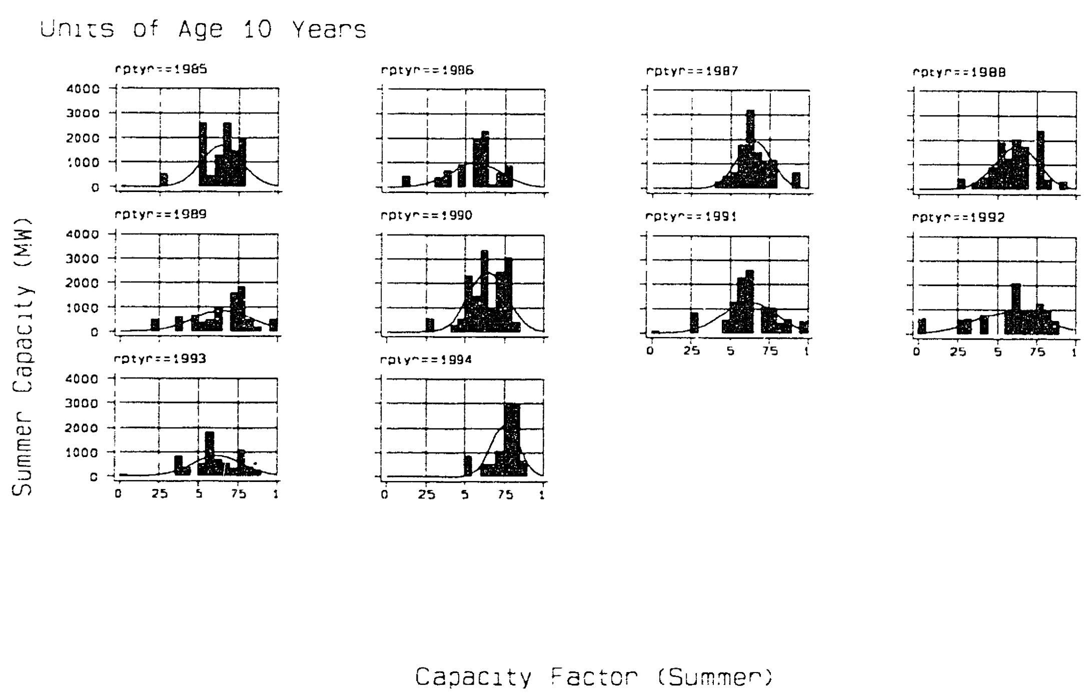

Figure A 13: Distribution of Capacity Factor Values for 10 Year Old Coal-fired Capacity by Reporting Year (1985-1994)

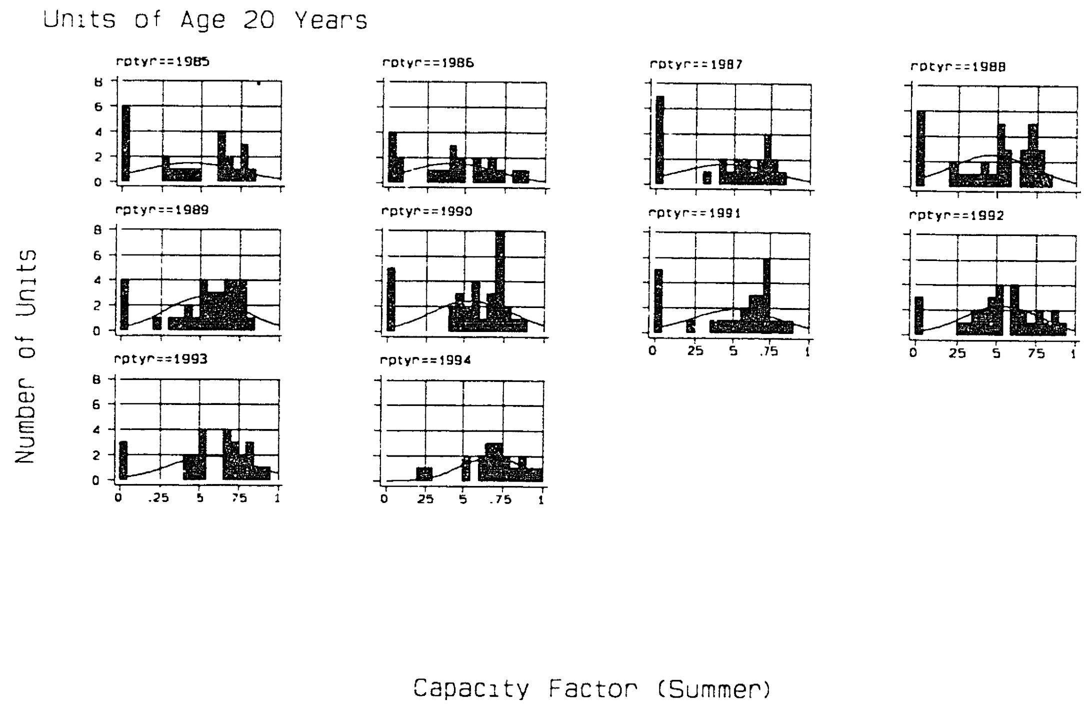

Figure A 14: Distribution of Capacity Factor Values for 20 Year Old Coal-fired Units by Reporting Year (1985-1994)

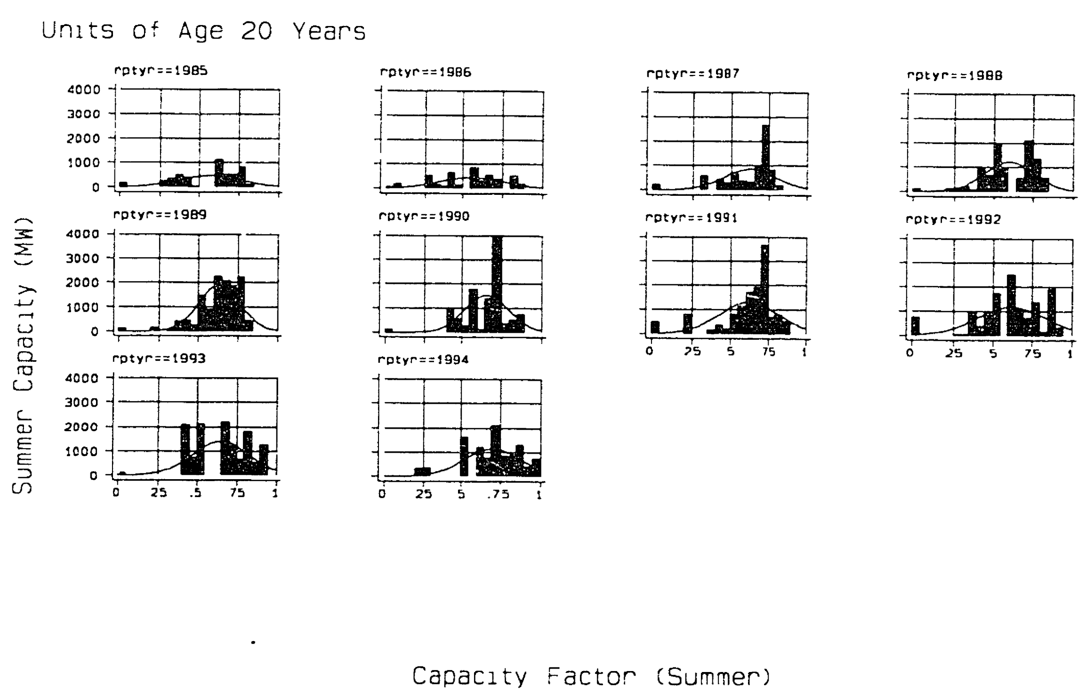

Figure A 15: Distribution of Capacity Factor Values for 20 Year Old Coal-fired Capacity by Reporting Year (1985-1994)

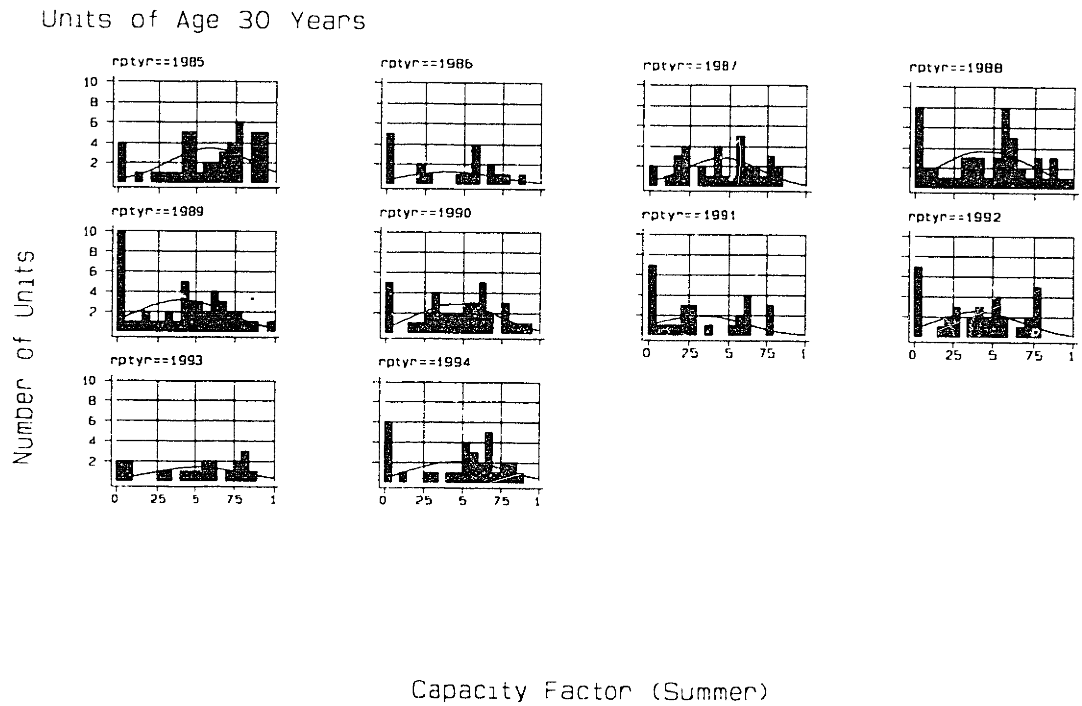

Figure A 16: Distribution of Capacity Factor Values for 30 Year Old Coal-fired Units by Reporting Year (1985-1994)

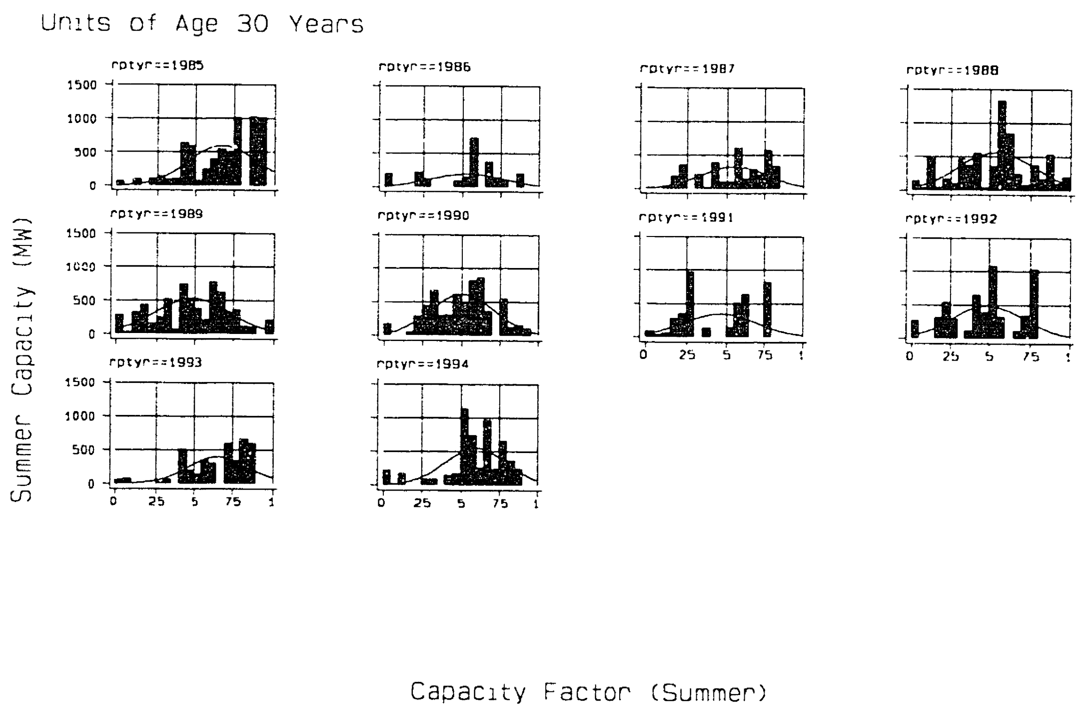

Figure A 17: Distribution of Capacity Factor for 30 Year Old Coal-fired Capacity by Reporting Year (1985-1994)

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