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Economic Analysis for the Proposed Revision of Steam-Electric Utility Industry Effluent Limitations Guidelines

ECONOMIC ANALYSIS FOR THE PROPOSED REVISION OF STEAM-ELECTRIC UTILITY INDUSTRY EFFLUENT LIMITATIONS GUIDELINES

OFFICE OF PLANNING AND EVALUATION
U.S. ENVIRONMENTAL PROTECTION AGENCY
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PREFACE

The attached document is a contractor's study prepared for the Office of Planning and Evaluation of the Environmental Protection Agency ("EPA"). The purpose of the study is to analyze the economic impact which could result from the application of alternative BAT, PSES, NSPS, PSNS guidelines established under the Federal Water Pollution Control Act (the Act), as amended.

The study supplements the technical study ("EPA Development Document") supporting the proposal of regulations under the Act. The Development Document surveys existing and potential waste treatment control methods and technologies within particular industrial source categories and supports proposed limitations based upon an analysis of the feasibility of these limitations in accordance with the requirements of the Act. Presented in the Development Document are the investment and operating costs associated with various alternative control and treatment technologies. The attached document supplements this analysis by estimating the broader economic effects which might result from the required application of various control methods and technologies.

The study has been prepared with the supervision and review of the Office of Planning and Evaluation of the EPA. This report was submitted in fulfillment of Contract No. 68-01-5840 by Temple, Barker & Sloane, Inc. This report reflects work completed as of August 1980.

This report is being released and circulated at approximately the same time as publication in the Federal Register of a notice of proposed rule making. The study is not an official EPA publication. It will be considered along with the information contained in the Development Document and any comments recieved by EPA on either document before or during proposed rule making proceedings necessary to establish final regulations. Prior to final promulgation of regulations, the accompanying study shall have standing in any EPA proceeding or court proceeding only to the extent that it represents the views of the contractor who studied the subject industry. It cannot be cited, referenced, or represented in any respect in any such proceeding as a statement of EPA's views regarding the steam-electric utility industry.

CONTENTS

I. EXECUTIVE SUMMARY

This report provides an economic and financial analysis of proposed revisions to the effluent limitations guidelines for best available technology economically achievable (BAT), new source performance standards (NSPS), and pretreatment standards as applied to the steam-electric utility industry. The economic evaluation is based on technical findings and cost data supplied by the United States Environmental Protection Agency (EPA) and its technical contractors in published reports. A final economic assessment will be prepared when the regulations are proposed.

In developing the effluent limitations guidelines, EPA has considered discharge standards for ten waste streams:

- Bottom ash transport water
- Fly ash handling water
- Recirculating cooling water
- Once-through cooling water
- Metal cleaning wastes
- Low volume wastes
- Boiler blowdown
- Coal pile runoff
- Chemical handling runoff
- Flue gas desulfurization waste water

At present, however, this report covers only the economic effects associated with BAT and pretreatment standards for once-through and recirculating cooling water and NSPS for both cooling water streams and for fly ash transport water. For the remaining waste streams the Agency has decided either not to require controls beyond those necessary to meet best practicable control technology (BPT) standards or to postpone consideration of regulations until more data concerning waste stream constituents and treatment technology effectiveness become available.

The following sections will briefly summarize the major findings of the economic analysis in the four main areas examined in this report. These areas are:

- A physical and economic profile of the industry.
- An estimate of the economic effects of the proposed regulations on individual utilities and on the electric utility industry.
- An assessment of the costs of the regulations relative to the amounts of pollutants removed; and
- A determination of the effects of the regulations on industry growth, employment, capital availability, and other factors as appropriate.

Profile of the Industry

The electric utility industry consists of about 750 individual utilities operating approximately 2,000 power plants with a combined operating capacity of approximately 588,000 megawatts (MW). Only the steam sector of the industry would be affected by the proposed regulations. This sector accounts for nearly 80 percent of the industry's capacity and 85 percent of the electricity generated annually. In the future the capacity of the industry is expected to grow at an overall annual rate of slightly more than 3 percent. The steam sector of the industry with a faster annual growth rate of 4.1 percent will increase its share of total industry capacity to over 85 percent by 1995.

The electric utility industry is the most capital-intensive industry in the United States. Its 1980 planned capital expenditures of $34 billion represent about 16 percent of total capital expenditures by U.S. industry. During the decade from 1979 to 1989 the industry will spend a further $381.2 billion (1980 dollars). To finance these expenditures it will raise $222 billion from external sources.

Expenditures for pollution control equipment by the electric utility industry account for about one-third of total pollution control expenditures by U.S. industry. The industry spent $2.9 billion in 1979 and it anticipates spending a further $3.6 billion in 1980 on air, water, and solid waste pollution control equipment.[1] Between one-third and one-fourth of the industry's annual pollution control expenditures go to water pollution control.

Recently the electric utility industry has been adversely affected by high interest rates and steep inflation. As a result of increasing costs of fuel, materials, and labor, average consumer charges have increased sharply. Meanwhile, electric utility stock prices fell by an average of 7.2 percent and as of December 31, 1979, the average market to book value ratio of electric utility stocks reached its lowest level since mid-1975. In March 1980 interest rates on Moody's Aa rated electric utility stocks reached their highest value (14 percent) in the history of the industry.

Economic Effects of the Proposed Regulations

The regulations currently being proposed will not add significantly to the cost of generating electricity. As shown in Table I-1 consumer charges will increase by one twenty-fifth of one percent and capital expenditures will increase by one-fiftieth of one percent as a result of compliance with the regulations. Although the industry will spend up to $80 million annually to comply and its cumulative capital expenditures will increase by $200 million over the period 1980-1995, these increases are very small relative to baseline industry costs.

Table I-1

OVERALL FINANCIAL EFFECTS OF THE PROPOSED EFFLUENT LIMITATIONS GUIDELINES

(increase over baseline in 1980 dollars)

	1985	1990	1995
Cumulative Capital Expenditures			
Millions of Dollars	$120	$150	$200
Percent of Baseline	.05%	.03%	.02%
Revenue Requirements			
Millions of Dollars	$60	$70	$80
Percent of Baseline	.04%	.04%	.04%
Operation and Maintenance Expense			
Millions of Dollars	$40	$60	$70
Percent of Baseline	.05%	.06%	.07%
Consumer Charge			
Mills per KWH	.02	.02	.02
Percent of Baseline	.04%	.04%	.04%

[1] Electrical Week, May 26, 1980.

At the individual plant level the economic effects of the proposed regulations are significant only at small plants that are more than 25 years old. At these plants a combination of low capacity factors and short remaining depreciable lives result in increases of 1.3 to 3.5 percent in the cost of generating electricity. Since most utilities also operate newer and larger plants this increase in the cost of generating electricity will not translate into similar increases in consumer charges. At newer and larger plants which account for most of the industry's capacity the cost of generating electricity will increase by 0.02 percent.

Cost-Effectiveness

The proposed regulations are more stringent than best practicable technology regulations for chlorine and for the 129 priority pollutants. The cost of chlorine removal increases dramatically from a cost of between $.77 and $4.55 for the first 17.4 million pounds of chlorine removed to $862 per pound for the final 34,000 pounds removed. This difference reflects not higher plant-level costs, which are roughly equivalent, but much lower quantities of chlorine present at certain plants.

Zinc, chromium, and chlorinated phenols in cooling water waste streams would also be eliminated by restrictions on the use of chemical additives containing the 129 priority pollutants. There would be no cost associated with using alternative chemicals not containing chlorinated phenols, and the cost of eliminating chromium and zinc would be $11 and $53 per pound respectively.

Effects on Industry Growth and Other Factors

Given the magnitude of the electric utility industry, the costs of the proposed regulations are insufficient to have an appreciable effect on its operating characteristics. The industry's financial parameter most affected by the proposed regulations is operation and maintenance expenses. Even this financial parameter, however, increases by less than one-tenth of one percent as a result of industry compliance with the regulations. No other financial parameter increases by more than one-twentieth of one percent.

II. DESCRIPTION OF THE ELECTRIC UTILITY INDUSTRY

This chapter briefly describes the electric utility industry's physical and financial characteristics to provide a basis for an assessment of the effects of the proposed effluent limitations guidelines on the industry. First, the physical configuration of the industry at the national, company, and plant levels is described emphasizing those aspects of the industry that are most likely to affect the overall costs of compliance with the proposed regulations. Second, financial aspects of the industry, including company revenues, total industry capitalization, and external financing requirements, are discussed. Finally, some of the more important issues facing the industry in the years ahead are described.

PHYSICAL DESCRIPTION OF THE ELECTRIC UTILITY INDUSTRY

By any measure, the electric utility industry is large. Comprising about 750 individual utilities operating over 2,600 steam and non-steam power plants, it has a total peak generating capacity of nearly 600,000 megawatts and in 1979 it generated 2,295 billion kilowatt-hours of electricity. In the process of generating electricity the industry utilizes over 60 trillion gallons of water annually for cooling, generating steam, and transporting ash and other wastes. The electric utility industry uses more water than any other industrial group in the nation.

In the future, the industry is expected to grow at an annual rate of about 3.1 percent (although estimates of future growth vary widely). Growth in the steam sector of the industry will be somewhat more rapid--about 4.1 percent per year. By 1995, there will be about 4,150 power plants with a generating capacity of 1,003,800 MW.

The power plant is the basic production unit of the electric utility industry, and the cost of complying with the revised BAT regulations will depend on the physical characteristics of each power plant. Plant characteristics that are most likely to affect costs of compliance with the effluent limitations guidelines that EPA either has considered or is proposing are: plant type, capacity, age, fuel type, and discharge and cooling system type. In the sections that follow each of these characteristics will be described.

Plant Type

For the purposes of this analysis the electric utility industry can be divided broadly into two plant types--steam and non-steam. Steam plants use steam to drive a turbine which in turn rotates an electric power generator. Steam is generated primarily by burning fossil fuels or, in a nuclear plant, by a nuclear fission reaction. Non-steam plants use either water (in a hydroelectric plant), a jet-like engine (in a gas turbine plant), or an internal combustion engine to rotate the generator.

The effluent limitations guidelines under review cover only power plants with steam boilers. Forty percent of all existing power plants have steam boilers. These steam-electric plants (referred to as the "steam sector" of the industry) represent 79 percent of the capacity and 85 percent of the generation of the electric utility industry. Details on the present and future generating capacity of the steam sector of the electric utility industry are shown in Table II-1.

Table II-1

PRESENT AND FUTURE CAPACITY
OF THE ELECTRIC UTILITY INDUSTRY
(capacity in gigawatts at year end)

	1978	1985	1990	1995
Generating Capacity				
Total Industry	573.8	750.3	834.9	1,003.8
Steam Sector	453.3	614.4	695.7	855.4

Source: DOE Inventory of Powerplants (1979), TBS estimates.

Capacity

Plant capacities range from less than 10 MW for small peaker plants to well over 1,000 MW for very large baseload plants. As shown in Table II-2, the distribution of plants by number of plants differs from the distribution by capacity. While slightly over 45 percent of the plants have capacities of less than 200 MW, less than 7 percent of the capacity is in these plants. Nearly 12 percent of the existing plants are in the 0-25 MW category, yet these plants represent only 0.3 percent of the generating capacity. Conversely, the 35 percent of the plants in the over-500 MW category account for over 81 percent of the generating capacity. Moreover, large plants are generally baseload units which operate at high capacity factors, while small plants are most frequently used to supplement baseload capacity during periods of peak demand. Consequently, large plants account for a greater percentage of total electric power generation than they do of total generating capacity.[1]

Table II-2

YEAR-END 1978 DISTRIBUTION OF STEAM-ELECTRIC PLANTS BY SIZE CATEGORY[1]

	0-25 MW	26-100 MW	101-200 MW	201-350 MW	351-500 MW	Over 500 MW	Total
Total MW in Category	1,273	9,466	16,777	24,125	33,282	368,342	453,265
Percent of Total Capacity	0.3%	2.1%	4.0%	5.3%	7.0%	81.3%	100.0%
Number of Plants	98	172	115	87	79	291	842
Percent of Total Plants	11.6%	20.4%	13.7%	10.3%	9.4%	34.6%	100.0%

[1]Excludes plants with zero net dependable capacity.

Source: DOE Inventory of Powerplants (1979).

Plant Age

The age of plants affected by the revised effluent limitations guidelines influences the economic impact of pollution control expenditures. Most plants have depreciable lives of 30 to 35 years. If pollution control equipment is installed at a 25-year-old plant, the investment may be amortized only over the plant's remaining 5- to 10-year depreciable life, resulting in high annual depreciation charges. Annual costs are lower, therefore, for the same equipment installed at newer plants. In most cases, the physical life of a plant exceeds its depreciable life but for the purposes of economic analysis, pollution control expenditures should be amortized over the remaining depreciable life.

[1]The number and capacity of plants in each category is based on the 1979 DOE Inventory of Powerplants database. Plants listed in the DOE Inventory as having a net dependable capacity of zero were excluded.

The age distribution of existing steam-electric power plants shows a definite correlation between plant size and age. As shown in Exhibit II-3, nearly 75 percent of the capacity has been built since 1960 and almost 90 percent of this capacity is in plants larger than 500 MW. By way of contrast only 54 percent of the capacity built prior to 1960 is in plants larger than 500 MW. Table II-3 illustrates these results in terms of age of the median, most recently built, and oldest quartiles of plants in each size category.

Table II-3

BOILER IN-SERVICE DATE FOR OLDEST, MEDIAN, AND MOST RECENTLY BUILT QUARTILES IN SELECTED PLANT SIZE CATEGORIES

	Plant Size Category (MW)						
Quartile	0-25	26-100	101-200	201-350	351-500	>500	Total
Oldest	Pre-1945	Pre-1945	1950	1950	1950	1965	1960
Median	1950	1950	1955	1955	1960	1970	1970
Most Recently Built	1955	1960	1960	1965	1970	1975	1975

Source: DOE Inventory of Powerplants (1979).

Fuel Type

Steam-electric plants use four major fuels--coal, oil, gas, and nuclear energy. As shown in Table II-4, coal-fired plants with an average capacity of nearly 650 MW account for slightly more than 50 percent of total capacity with just over 40 percent of the plants. Oil plants average 462 MW and make up 22 percent of steam-electric capacity with 26 percent of the plants. With an average capacity of 327 MW, gas plants are generally smaller than other plants and contribute only 15 percent of total capacity with 25 percent of the plants. Nuclear plants on the other hand average 1,400 MW and account for 12 percent of steam-electric capacity with 5 percent of the plants. Finally, plants using unknown, multiple, or "other" fuels such as refuse constitute 2 percent of the plants but less than 1 percent of capacity.

Table II-4

DISTRIBUTION OF CAPACITY
AND PLANTS BY FUEL TYPE
1978

Fuel	Number	Capacity (MW)
Coal	352	227,366
Oil	220	101,701
Gas	209	68,371
Nuclear	38	53,825
Unknown	18	551
Multiple	3	1,412
Other	2	39
Total	842	453,265

Source: DOE, Inventory of Powerplants (1979).

As shown in Table II-5, the mix of fuel types used by steam-electric power plants is expected to change dramatically over the next 10 years. Depending on future petroleum prices, the stringency of federal fuel-use regulations, and the availability of capital for coal conversion, oil and gas capacity may decrease to less than half of what it is now by 1990 or 1995. Given the growth in other fuel types, this decline will mean that oil and gas generation will account for less than 10 percent of total generation by 1995 as compared to 39 percent in 1979.

The future of nuclear capacity is less certain. Increasing construction costs, siting difficulties, and the aftermath of the events at Three Mile Island may serve to dampen a rising trend in nuclear capacity. On the other hand, many major utilities remain committed to a program of major nuclear construction. Consequently, in its latest "Annual Electrical Industry Forecast," Electrical World projects that nuclear construction will decline from previously projected levels more as a function of a low peak demand growth rate than as a result of the Three Mile Island incident.[2] According to Electrical World, by 1995 nuclear plants will account for approximately 23 percent of total generating capacity, nearly double the current proportion of nuclear capacity.

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[2]Electrical World, "30th Annual Electrical Industry Forecast," September 15, 1979, p. 62.

Table II-5

STEAM-ELECTRIC CAPACITY
CATEGORIZATION BY FUEL TYPE

(capacity in gigawatts)

	1985	1990	1995
Coal Capacity	301.8	365.1	473.9
Number of Plants	467	565	734
Oil/Gas Capacity	173.5	157.4	100.4
Number of Plants	438	397	253
Nuclear Capacity	139.0	173.1	281.0
Number of Plants	98	122	198

Source: Electrical World, Sept. 15, 1979, and TBS estimates.

Coal capacity will clearly increase both in absolute terms and as a percent of total capacity over the next 15 years. The extent of this increase will depend on the increase in total demand, the decrease in oil and gas capacity, and the future of nuclear power plants. Given escalating oil prices and federal government policies mandating conversion from oil to coal, coal capacity will increase at the expense of oil and gas capacity. To the extent that nuclear capacity additions fall short of current projections, the shortfall will be made up by coal if total capacity reaches projected levels.

FINANCIAL AND ECONOMIC DESCRIPTION OF THE ELECTRIC UTILITY INDUSTRY

An understanding of the economic struture and operating characteristics of the electric utility industry is important to put in perspective the costs of the proposed regulations. The following section will examine three key areas that will influence the level of economic effects resulting from compliance with the proposed regulations. These areas are industry economics and financing, the present financial condition of the industry as a whole, and company economics and financing.

Industry Economics and Financing

The electric utility industry is the most capital-intensive industry in the United States. Its current planned capital expenditures amount to $34 billion in 1980.[3] This figure represents about 16 percent of the total capital expenditures of all U.S. business in 1980. During the next decade the electric utility industry will require large amounts of capital for system expansion and pollution control expenditures. From 1965 to 1978 the capitalization of the investor-owned sector of the industry increased from $62.6 billion to $174.9 billion, or by 178 percent. In the 10 years from 1979 to 1989, the capitalization of the electric utility industry will rise by a further 169 percent to $468.1 billion (1980 dollars). The industry will spend over $381.2 billion during the next decade. To finance these expenditures, approximately $222.0 billion will have to be raised from the sale of bonds, preferred stock, and common stock.

As a result of increasing costs of fuel, materials, and labor, the average price paid by the consumer (omitting any costs due to the proposed effluent limitations guidelines) will rise from 45.9 mills per kilowatt-hour in 1980 to 73.5 mills in 1985. If the effects of inflation are removed, the cost of generating electricity will remain relatively constant, increasing only by 6 percent by 1985 and decreasing by approximately 4 percent between 1985 to 1995. The decrease in the real cost of generating electricity between 1985 and 1995 results from a leveling off in the rate of increase in peak electricity demand. As a result of this leveling off, generating capacity will be added at a slower rate and capital charges will decrease.

The electric utility industry accounts for about one-third of total expenditures for pollution control equipment by U.S. industry. According to an annual survey of industry spending plans by McGraw-Hill, the industry spent $2.9 billion in 1979 and anticipates spending $3.6 billion in 1980 for air, water, and solid waste control. Also according to the McGraw-Hill survey, water pollution control expenditures in 1980 are expected to decrease by approximately 7 percent to 872 million from their 1979 level of $938 million. This level of expenditure will amount to more than one-quarter of all spending by U.S. industry for water pollution control.[4]

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[3] Electrical World, September 15, 1979.

[4] Electrical Week, May 26, 1980.

Industry financial and operating projections through 1995 are shown in Exhibits II-6 through II-12, and are summarized in Table II-6. The exhibits and the table are "baseline" projections. That is, they exclude the impacts of the proposed effluent limitations guidelines and the revised new source performance standards for air as promulgated on June 11, 1979. They assume that all power plants are in compliance with best practicable technology standards.

Table II-6

BASELINE ELECTRIC UTILITY INDUSTRY FINANCIAL AND OPERATING STATISTICS[1]

(dollar figures in billions of current dollars)

	1965[a]	1975[a]	1978[a]	1985[b]	1990[b]	1995[b]
Total Capacity (GW)	236.1	508.4	579.3	750.3	834.9	1,003.8
Total Energy Sales (GWH X 103)	957.1	1,738.0	2,017.8	2,651.8	3,183.1	3,776.8
Total Capitalization[2]	$62.6	$167.4	$219.0	$371.8	$701.6	$1,683.9
Annual Operating Revenues	$15.2	$46.9	$69.9	$194.9	$329.0	$590.3
Average Consumer Charge (mills per KWH)	15.9	27.0	34.6	73.5	103.4	156.3
Cumulative Capital Expenditures from 1979 to Year				$263.0	$710.9	$1,958.9
Cumulative External Financing from 1979 to Year				$147.0	$434.2	$1,292.2

[1]Includes both steam and non-steam sectors.

[2]Investor-owned utilities' capitalization increased by 26 percent to account for publicly owned utilities.

[a]Source: Statistical Yearbook, Edison Electric Institute, 1978.

[b]Source: Exhibits II-4 through II-10.

Present Financial Condition of the Electric Utility Industry

The electric utility industry's financial condition was adversely affected by high interest rates and steep inflation during 1979. Based on the Salomon Brothers 100-company index, average electric utility stock prices fell by 7.2 percent in

1979. Deducted from an average yield of 10.1 percent, this decline resulted in an average total return of 2.9 percent. This return compares to the average return on the Dow Jones Industrial index of 10.2 percent and the Standard & Poors 400 Industrial Index return of 18.4 percent. The average market/book value ratio of the 100-company electric utility index as of December 31, 1979, was 78 percent, the lowest value since mid-1975. Moreover, the interest rate on Moody's Aa rated electric utility bonds issued in March 1980 was almost 14 percent, the highest rate in the history of the industry.

Prospects for the future are uncertain--an oil shortage caused by political turmoil in the Middle East would directly increase costs for many eastern utilities which rely heavily on oil. Other utilities would be affected indirectly as tight oil supplies spur inflation and as costs of alternative fuels rise with increased demand. Higher costs of electricity could reinforce the trend toward greater conservation of electricity by consumers.

To improve its financial health, the utility industry will have to budget its expenditures carefully. Sales are not expected to increase as rapidly as they did in the past, and the cost of fuel and power plant construction will continue to rise even in the absence of foreign supply problems. Some utilities may find it difficult to finance all the construction projects they would like; however, a reduction in demand forecasts and high reserve margins as a result of the continued slow growth in electricity sales may reduce the need for construction of new capacity. Conversely, additional pollution control expenditures increase the number of potential utility projects without increasing the supply of capital.

Company Economics and Financing

The company is the basic financial unit of the electric utility industry. It is at the company level that the costs of the proposed effluent limitation guidelines will be financed. Increased operating and capital costs will be aggregated by the company and passed on to customers.

Company size can be measured in any number of ways, but most common are operating revenues, generating capacity, and number of customers. These factors are all related, however, and the discussion here will focus on operating revenues. The distribution of companies by operating revenue reflects a high degree of concentration in the industry. While 87 percent of the companies have revenues below $150 million, these companies account for only 17 percent of the generating capacity. Companies with over $700 million in revenues account for less than 2 percent of the companies and 31 percent of the generating capacity.

The number of plants owned by a company is a function of company size, and the number of plants owned by a company can greatly influence the impact of the effluent limitation guidelines. For a small company with one or two generating plants the probability is that either all or none of the company facilities will be affected. Larger companies with several generating stations will usually have a plant mix that results in a less than universal effect.

Company size also often determines a company's financial and operating strategy. Small companies frequently plan on very little capacity expansion, expecting instead to meet sales and demand growth by purchasing additional electricity from other, larger companies. As a result, their planned level of capital expenditures can appear disproportionately low compared to those of large companies. Additional expenditures required to comply with effluent limitations guidelines could cause a relatively large percentage increase in construction expenditures. Large companies usually have more ambitious capital expenditure programs which would dilute the effects of additional expenditures for pollution control equipment.

ISSUES CONFRONTING THE ELECTRIC UTILITY INDUSTRY

In addition to escalating fuel prices and government policy which, as was noted above, are resulting in a changing mix of fuel types in the industry, a number of other issues cause uncertainty concerning the future of the industry. The major such issues include:

- The effect of rising prices, conservation, government energy policy, and load management on the demand for electricity;
- The future of nuclear power;
- The difficulty in siting new power plants; and
- Coal conversion.

Actual growth in demand in the past several years has been lower than either the historical rate of growth in demand or the rate projected by government agencies and the electric utility industry. For example, since 1973 demand for electricity has grown at an annual rate of 2.9 percent as compared to 7.6 percent in the six years prior to 1973. In 1978 and 1979 government and industry sources consistently overestimated growth in peakload demand with projections ranging from 3.5 to 5.4 percent as compared to actual growth in 1979 of 0.6 percent.

In the future, numerous factors will continue to influence demand growth and the exact outcome is uncertain. The cost of electricity will continue to rise with increasing fuel and capital costs, both of which have consistently outpaced inflation. In addition, government incentives for conservation and an increasing public awareness of the need for conservation will undoubtedly have some impact on energy use.

Incentives to increase the use of existing power plants rather than build additional plants are becoming greater as new plant sites become more difficult to find and as costs of new plant construction rise. Load management will be one means of increasing the use of available capacity. This approach will involve increased use of plants during off-peak hours, accomplished through the use of rates which encourage off-peak use, and the use of sophisticated methods to interrupt segments of the load for short periods each day, thus reducing the overall peak.

The future of nuclear power is another important issue facing the electric utility industry. Siting problems, regulatory difficulties, and the erratic operating performance of some nuclear plants have increased the uncertainty involved in estimating the cost of future nuclear power plants. Depending on the assumptions used, nuclear power does not always have a clear economic advantage over coal-generated power. While many experts feel nuclear power could regain its advantage if the regulatory and siting process were streamlined, it is unclear when or if this will ever happen. In the meantime, many utilities are canceling orders for nuclear plants and building coal-fired plants which will generate additional air and water pollutants.

The siting of new power plants, both fossil and nuclear, has become an important issue in the past few years. The water consumption, fuel handling and transportation problems, emissions, safety considerations, and visual impact of a 1,000 MW power plant make siting a difficult and lengthy process. The regulatory proceedings required for new plant approval have also become more complex and time-consuming. As a result, the time from plant inception to operation has increased to ten years for nuclear plants and seven to eight for coal plants. These delays have substantially raised the price of plant construction. The cost increases on new plants could limit the amount of funds available for other expenditures, such as pollution control equipment.

Finally, coal conversion will be a major issue facing electric utilities. Rising oil and gas prices will act as the major incentive for utilities to shift away from these fuels. This trend will be reinforced by reductions in the use of oil and gas mandated by the federal government. The Fuel Use Act severely limits the use of oil and gas in new utility boilers, and under the Power Plant Petroleum Conservation Act being drafted, the federal government may mandate a 50 percent reduction in utility oil use by 1990. It is uncertain at this time, however, how the cost of conversion to coal will be financed and how the nation's coal supply and transportation network will accommodate a greatly increased demand for coal.

Exhibit II-1

NUMBER OF EXISTING STEAM-ELECTRIC POWER PLANTS
BY FUEL TYPE AND SIZE

(number of plants)

	Plant Size Categories						
Fuel Type	0-25 MW	26-100 MW	101-200 MW	201-350 MW	351-500 MW	More Than 500 MW	Total
Existing (1979)							
Coal	35	63	36	38	35	145	352
Oil/Gas	48	102	76	48	44	111	429
Nuclear	0	2	2	0	0	34	38
Other	15	5	1	1	0	1	23
Total	98	172	115	87	79	291	842

Source: DOE Inventory of Powerplants (1979).

Exhibit II-2

CAPACITY OF EXISTING AND NEW STEAM-ELECTRIC POWER PLANTS
BY FUEL TYPE AND SIZE

1978-1995

(gigawatts)

	Plant Size Categories						
Fuel Type	0-25 MW	26-100 MW	101-200 MW	201-350 MW	351-500 MW	More Than 500 MW	Total
Existing (1978)							
Coal	.46	3.46	5.59	10.47	14.77	192.61	227.37
Oil/Gas	.67	5.69	10.71	13.33	18.52	121.16	170.07
Nuclear	0	.16	.35	0	0	53.31	53.83
Other	.14	.16	.13	.32	0	1.25	2.10
Total	1.27	9.47	16.78	24.12	33.29	368.33	453.37
Additions (1978-1985)							
Coal							79.20
Oil/Gas							19.80
Nuclear							85.40
Total							184.40
Additions (1986-1995)							
Coal							187.30
Oil/Gas							.20
Nuclear							142.10
Total							329.60
Total Additions (1978-1995)							514.00

Source: DOE Inventory of Powerplants.

Exhibit II-3

DISTRIBUTION OF STEAM-ELECTRIC CAPACITY BY PLANT SIZE AND IN-SERVICE YEAR

Plant Age Category	Plant Size Category							Percent of Total Capacity
	0-25	26-100	101-200	201-350	351-500	>500	Total	
Pre-1960								
MW	1,154	6,656	12,926	17,362	16,749	64,968	119,815	
Percent of Age Category	1	5.6	10.8	14.5	14	54	100	26
1961-1970								
MW	344	2,157	4,052	6,570	9,630	112,844	135,597	
Percent of Age Category	.3	1.6	3.0	4.8	7.1	83	100	30
Post-1970								
MW	20	1,135	1,543	3,942	7,539	184,502	198,681	
Percent of Age Category	.01	.6	.8	2	3.8	93	100	44
Total								
MW	1,518	9,948	18,521	27,874	33,918	362,314	454,093	
Percent of Age Category	.3	2	4	6	7	80	100	100

Source: DOE Inventory of Powerplants, 1979.

Exhibit II-4

BASELINE PROJECTIONS
PTm GROSS ADDITIONS TO GENERATING PLANT
INCLUDING CONVERSIONS TO COAL AND OIL
(gigawatts)

	TOTAL CAPACITY	TOTAL ADDTNS.	FOSSIL SUBTOTAL	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED	PEAKER
1979	616.8	31.0	15.0	13.1	1.8	.0	9.3	5.7	.3	.8
1980	639.1	25.4	14.0	13.8	.2	.0	8.5	.6	1.7	.6
1981	656.8	20.9	8.4	7.5	.9	.0	8.6	.7	2.3	.9
1982	683.9	30.2	14.0	13.3	.7	.0	14.5	.2	.8	.7
1983	705.3	24.6	10.1	10.1	.0	.0	14.3	.1	.0	.1
1984	728.1	26.2	9.3	9.3	.0	.0	16.6	.0	.0	.3
1985	750.3	25.9	12.1	12.1	.0	.0	13.6	.0	.0	.2
1986	766.1	19.7	6.8	6.8	.0	.0	12.4	.0	.0	.5
1987	777.3	15.7	4.9	4.7	.2	.0	10.2	.0	.0	.6
1988	790.5	17.6	9.1	9.1	.0	.0	7.8	.0	.0	.7
1989	811.4	26.0	22.6	22.6	.0	.0	2.8	.0	.0	.6
1990	835.1	29.8	27.2	27.2	.0	.0	1.0	.0	.0	1.6
1991	861.6	37.6	29.3	29.3	.0	.0	6.5	.0	.0	1.8
1992	891.3	42.2	30.0	30.0	.0	.0	10.3	.0	.0	1.9
1993	924.7	46.3	20.4	20.4	.0	.0	24.0	.0	.0	1.9
1994	962.0	51.6	18.0	18.0	.0	.0	31.6	.0	.0	2.0
1995	1003.9	56.8	19.2	19.2	.0	.0	35.5	.0	.0	2.1
1996	1050.9	56.3	22.9	22.9	.0	.0	30.6	.0	.0	2.8
1997	1103.6	63.5	25.8	25.8	.0	.0	34.4	.0	.0	3.3
1998	1162.6	69.4	28.1	28.1	.0	.0	37.5	.0	.0	3.8

Source: TBS.

Exhibit II-5

BASELINE PROJECTIONS
PTm TOTAL GENERATION BY DRIVER
INCLUDING CONVERSIONS TO COAL AND OIL
(billion KWH)

	TOTAL GENER.	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED	PEAKER
1979	2295.0	1068.7	401.2	207.4	278.9	270.3	34.7	33.7
1980	2340.9	1088.9	376.5	195.6	340.8	266.5	39.2	33.3
1981	2472.0	1155.3	371.0	194.6	392.8	275.9	47.5	34.8
1982	2598.1	1223.0	356.0	189.1	466.6	277.4	50.6	35.3
1983	2702.0	1276.0	338.2	183.3	539.5	278.4	51.2	35.4
1984	2804.6	1321.3	319.4	176.9	621.9	277.9	51.6	35.5
1985	2914.0	1383.6	301.5	170.7	692.0	278.3	52.2	35.7
1986	3021.8	1435.2	285.6	166.7	763.6	281.2	53.3	36.3
1987	3136.7	1489.7	272.2	163.6	832.4	286.6	54.8	37.4
1988	3255.9	1557.8	268.9	158.8	885.7	290.2	56.1	38.3
1989	3376.3	1689.8	241.2	141.6	913.5	293.8	57.4	39.1
1990	3497.9	1839.2	211.8	123.4	928.5	296.1	58.4	40.6
1991	3620.3	1985.1	175.7	100.4	963.2	295.4	58.8	41.8
1992	3747.0	2121.4	140.5	78.2	1012.4	292.9	58.9	42.8
1993	3878.2	2194.8	108.0	58.3	1126.4	288.6	58.6	43.5
1994	4013.9	2232.3	87.9	45.4	1265.3	281.7	57.8	43.4
1995	4150.4	2262.7	69.6	33.9	1410.6	273.7	56.7	43.2
1996	4291.5	2311.7	57.3	27.0	1528.9	266.9	55.9	43.9
1997	4437.4	2359.7	45.7	20.5	1652.8	259.3	54.8	44.7
1998	4588.3	2408.4	35.6	15.1	1778.9	251.1	53.6	45.6

Exhibit II-6

BASELINE PROJECTIONS
ELECTRIC UTILITY INDUSTRY CAPACITY

(million KW and billion KWH)

	PEAK KW	KWH GEN	NET KWH SALES	12/31 CAPACITY	TOTAL ADDNS	TOTAL RETIRED
1979	410.7	2295.0	2088.4	616.8	31.1	2.2
1980	414.4	2340.9	2130.2	639.0	25.4	3.1
1981	439.3	2472.0	2249.5	657.0	20.9	3.2
1982	459.0	2599.1	2364.2	683.7	30.2	3.2
1983	479.2	2702.0	2458.8	705.2	24.6	3.3
1984	501.3	2804.6	2552.2	728.1	26.2	3.3
1985	524.3	2914.0	2651.8	750.3	25.9	3.8
1986	547.4	3021.8	2749.9	765.9	19.7	3.9
1987	571.5	3136.7	2854.4	777.2	15.7	4.4
1988	596.6	3255.9	2962.8	790.3	17.6	4.4
1989	622.9	3376.3	3072.5	811.3	26.0	4.9
1990	650.3	3497.9	3183.1	834.9	29.8	6.1
1991	678.2	3620.3	3294.5	861.5	37.6	11.1
1992	707.4	3747.0	3409.8	891.2	42.2	12.5
1993	737.8	3878.2	3529.1	924.6	46.3	12.9
1994	769.6	4013.9	3652.7	962.0	51.6	14.3
1995	801.9	4150.4	3776.8	1003.8	56.8	14.9

Exhibit II-7

BASELINE PROJECTIONS
PTm FUELS CONSUMED FOR GENERATION OF ELECTRICITY
INCLUDING CONVERSIONS TO COAL AND OIL

(conventional steam and peaking units)

	TOTAL GENERATION	COAL (MM TONS)	OIL (MM BBLS)	GAS (BCF)
1979	2295.0	505.0	737.5	2382.9
1980	2340.9	512.9	694.9	2254.0
1981	2472.0	544.0	688.0	2246.7
1982	2598.1	574.5	663.6	2186.1
1983	2702.0	598.9	635.3	2115.2
1984	2804.6	619.8	605.2	2037.6
1985	2914.0	648.3	576.9	1962.8
1986	3021.8	672.8	552.7	1912.3
1987	3136.7	699.1	531.6	1884.8
1988	3255.9	731.0	527.4	1838.6
1989	3376.3	788.9	481.5	1662.7
1990	3497.9	854.0	433.5	1478.4
1991	3620.3	917.1	373.4	1242.3
1992	3747.0	975.6	314.5	1013.6
1993	3878.2	1006.5	259.7	807.6
1994	4013.9	1021.3	224.6	670.8
1995	4150.4	1032.8	192.4	548.3
1996	4291.5	1052.4	171.9	477.3
1997	4437.4	1071.3	152.5	410.7
1998	4588.3	1090.5	135.9	355.7

Exhibit II-8

BASELINE PROJECTIONS
ELECTRIC UTILITY INDUSTRY FINANCIAL FORECASTS

(dollar figures in billions of 1980 dollars;
consumer charge in mills)

	CWIP	CE	CE - CWIP	EXT FIN	OPER REV	CONS CHRG
1979	49.23	20.31	31.53	7.66	87.06	41.69
1980	51.64	33.04	26.56	19.95	97.71	45.87
1981	59.56	35.80	23.66	22.30	105.65	46.97
1982	55.74	35.75	34.65	21.95	112.00	47.37
1983	53.87	33.14	30.45	18.91	117.19	47.66
1984	48.22	31.00	32.43	16.79	125.04	48.99
1985	41.86	28.83	31.70	14.36	128.93	48.62
1986	42.55	29.65	25.97	15.07	130.90	47.60
1987	52.04	35.05	22.33	20.19	133.95	46.93
1988	67.38	44.39	25.06	28.50	142.75	48.18
1989	83.07	54.26	33.69	36.34	145.53	47.37
1990	102.16	63.73	38.48	44.09	148.09	46.52
1991	117.33	71.74	49.01	49.68	151.15	45.88
1992	131.32	78.78	56.09	54.41	159.16	46.68
1993	143.88	86.88	64.60	59.92	165.93	47.02
1994	155.87	95.85	73.20	65.94	172.90	47.34
1995	167.05	103.82	81.10	70.72	180.86	47.89

	CUMM CE	CUMM - CWIP	CUMM EX FIN	CUMM OPER	O+M	CUMM O+M
1979	20.31	31.53	7.66	87.06	53.91	53.91
1980	53.35	58.09	27.62	184.77	62.91	116.83
1981	89.16	81.76	49.91	290.42	71.33	188.16
1982	124.90	116.40	71.87	402.43	76.36	264.52
1983	158.04	146.85	90.77	519.61	79.36	343.89
1984	189.04	179.28	107.57	644.65	85.56	429.45
1985	217.88	210.99	121.93	773.58	88.29	517.73
1986	247.53	236.96	137.00	904.48	88.23	605.96
1987	282.58	259.29	157.20	1038.43	89.62	695.59
1988	326.97	284.35	185.69	1181.17	97.56	793.15
1989	381.23	318.04	222.04	1326.70	99.56	892.71
1990	444.96	356.52	266.12	1474.79	99.49	992.20
1991	516.70	405.53	315.80	1625.95	98.76	1090.96
1992	595.48	461.62	370.22	1785.10	101.90	1192.86
1993	682.36	526.22	430.14	1951.03	102.31	1295.17
1994	778.21	599.42	496.08	2123.93	101.45	1396.62
1995	882.03	680.52	566.80	2304.79	100.63	1497.25

Exhibit II-9

BASELINE PROJECTIONS
ELECTRIC UTILITY INDUSTRY FINANCIAL FORECASTS

(dollar figures in billions of current dollars; consumer charge in mills)

	CWIP	CE	CE - CWIP	EXT FIN	OPER REV	CONS CHRG
1979	45.16	18.63	28.92	7.03	79.87	38.24
1980	51.64	33.04	26.56	19.95	97.71	45.87
1981	64.86	38.99	25.77	24.28	115.05	51.15
1982	66.16	42.43	41.13	26.06	132.95	56.23
1983	69.64	42.84	39.36	24.44	151.48	61.61
1984	67.63	43.48	45.49	23.56	175.37	68.71
1985	63.29	43.60	47.93	21.72	194.93	73.51
1986	69.28	48.28	42.29	24.54	213.15	77.51
1987	91.68	61.75	39.35	35.58	236.01	82.68
1988	128.56	84.71	47.83	54.37	272.37	91.93
1989	170.87	111.62	69.31	74.76	299.34	97.43
1990	226.95	141.57	85.48	97.94	328.98	103.35
1991	281.49	172.13	117.59	119.20	362.65	110.08
1992	340.28	204.13	145.34	141.00	412.40	120.95
1993	402.64	243.13	180.77	167.69	464.34	131.57
1994	471.10	289.69	221.23	199.28	522.56	143.06
1995	545.27	338.88	264.71	230.83	590.34	156.31

	CUMM CE	CUMM - CWIP	CUMM EX FIN	CUMM OPER	O+M	CUMM O+M
1979	18.63	29.92	7.03	79.87	49.46	49.46
1980	51.67	55.48	26.98	177.58	62.91	112.38
1981	90.67	81.26	51.27	292.64	77.68	190.06
1982	133.10	122.39	77.32	425.59	90.64	280.70
1983	175.94	161.75	101.76	577.07	102.59	383.29
1984	219.41	207.23	125.32	752.43	120.00	503.29
1985	263.01	255.16	147.03	947.36	133.49	636.77
1986	311.29	297.45	171.58	1160.51	143.67	780.44
1987	373.04	336.80	207.16	1396.52	157.91	939.35
1988	457.75	384.63	261.53	1668.89	186.16	1124.51
1989	569.37	453.94	336.28	1968.24	204.80	1329.30
1990	710.93	539.41	434.22	2297.22	221.01	1550.31
1991	883.06	657.00	553.42	2659.87	236.95	1787.26
1992	1087.18	802.33	694.42	3072.27	264.04	2051.30
1993	1330.31	983.10	862.10	3536.61	286.31	2337.61
1994	1620.00	1204.33	1061.38	4059.17	306.60	2644.21
1995	1958.88	1469.04	1292.22	4649.51	328.48	2972.68

III. PLANT- AND INDUSTRY- LEVEL EFFECTS OF THE PROPOSED EFFLUENT LIMITATIONS GUIDELINES ON THE STEAM-ELECTRIC INDUSTRY

The economic effects of the proposed effluent limitations on the electric utility industry were examined at two levels: the individual power plant and the entire electric utility industry. Economic effects at the company level were not examined separately because the cost of compliance for an individual utility is simply the sum of the costs for all power plants that it operates. These costs would be diluted by non-steam generating facilities operated by the utility.

This chapter will present the results of both the plant-level and industry-level analysis of the economic effects of the proposed regulations. At this time the Agency is proposing guidelines that require controls beyond BPT for the following waste streams: once-through and recirculating cooling water from existing direct dischargers, recirculating cooling water from existing indirect dischargers, and cooling water as well as fly ash transport water from new plants. The remaining waste streams are either being proposed with no additional requirements beyond BPT or reserved for future consideration. Since the cost of compliance with potential regulations on the ash transport waters are much higher than those of the proposed regulations, the costs and economic effects described in this analysis represent only a small portion of the potential costs of effluent limitations guidelines for the electric utility industry.

REGULATIONS

The proposed effluent limitations guidelines are incorporated in four separate proposed regulations: best available technology, new source performance standards, pretreatment standards for existing sources, and pretreatment standards for new sources. The proposed standards will require the following treatments:

- For once-through cooling water: a chlorine minimization program at all direct discharging plants that chlorinate (approximately 334 plants) and, in addition, dechlorination at all plants that fail to meet a standard of 0.14 milligrams per liter total residual chlorine (TRC) through chlorine minimization (167 plants).

- For recirculating cooling water: declorination at all direct discharging plants that chlorinate (approximately 197 plants) and use of alternative chemicals at plants using scaling and corrosion inhibitors and biocides containing the 129 priority pollutants.

- For other waste streams (ash handling waters at existing plants, low volume and metal cleaning wastes, boiler blowdown, and runoff from coal piles and chemical handling areas): no controls beyond those already required by BPT standards.

- For indirect discharging plants (those discharging into publicly owned treatment works): no limitations on effluent chlorine concentrations, but, as for direct dischargers, use of alternative biocides and scaling and corrosion inhibitors at recirculating cooling water plants using the 129 priority pollutants.

- For new plants: zero discharge of fly ash transport water and cooling water limits similar to those for existing direct discharging plants.

The following sections will describe the effects of requiring these technologies first at the plant level and then at the industry level.

PLANT-LEVEL EFFECTS

To determine the effects of the proposed regulations on individual power plants, several model plants were developed to represent a range of plant sizes, ages, and other characteristics. The cost of generating electricity at each of the model plants was calculated and the additional cost associated with complying with the proposed regulations was then determined. Each of these steps is described below.

Selection of Model Plants

Three criteria were used in the selection of model plants for the plant-level analysis--size, age, and cooling system type. As will be discussed below, these criteria were selected to encompass both those plants that would be most affected by the proposed regulations and those plants that account for most of the industry's generating capacity.

Size

Since the costs of compliance with the proposed regulations vary predictably with plant size, three plant sizes were examined--25, 100, and 1,000 MW.[1] The 25 and 100 MW plants were used to identify economic effects on small plants which account for a major portion of the total number of steam-electric plants. For example, 56 percent of all steam-electric plants have capacities of less than 350 MW. The 1,000 MW plants, on the other hand, represent the less numerous plants with capacities greater than 500 MW, which account for approximately 80 percent of the industry's capacity.

Age

Plant age is an important determinant of the plant-level effects of the proposed effluent limitations guidelines. Three major age-related factors influence plant-level compliance costs:

- Retrofit premiums,
- Plant design, and
- Remaining depreciable lives.

A critical distinction in the analysis is that between new and existing plants. In the future, plants will be designed taking into account the proposed effluent limitations, avoiding retrofit premiums and design changes that the proposed guidelines may necessitate for existing plants. Shorter depreciable lives, on the other hand, differentiate recently built existing plants from older plants.

Retrofit premiums are the costs over and above normal costs of installing pollution control equipment which result from the necessity of working around existing facilities and connecting equipment to a facility which was not originally designed for such equipment. In addition to these cost premiums, old plants may be limited in the amount of land available on-site to house newly mandated equipment.

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[1]The plant-level analysis for regulations not currently being proposed is considerably more complex in that costs of compliance with these regulations are much greater and vary less predictably with plant size.

Plant design may be considered a form of retrofit costs, but it is useful to differentiate it from conventional retrofit costs. In the case of plant design, additional costs result not from the need to install pollution control equipment around existing equipment, but from the need to change the operating characteristics of the plant. Among the technologies considered by the Agency, the clearest example of the influence of plant design is dry fly ash handling. If existing plants were required to install dry fly ash handling systems, they would incur the substantial costs of removing existing wet systems and installing dry systems. New plants, on the other hand, will incur no additional costs by installing dry systems because the new plant costs of the two systems are approximately equivalent. For this reason, there is no incremental cost associated with the NSPS requirement for dry fly ash handling.

The remaining depreciable life of a plant affects the period over which the capital costs of pollution control equipment can be amortized. The older the plant is when the effluent limitations guidelines go into effect, the shorter the amortization period for pollution control equipment installed. A shorter amortization period at a given interest rate results directly in a higher annual capital cost of compliance with the proposed regulations.

For purposes of the plant-level analysis, the age of existing plants was based on the median age of plants in each size category in the DOE Inventory of Powerplants. A 25 MW new plant was not considered because few plants smaller than 100 MW are currently being built on a non-experimental basis.

Cooling System Type

Three different types of plants were analyzed at the plant level--once-through plants that would comply through chlorine minimization alone, once-through plants requiring chlorine minimization and dechlorination, and recirculating cooling water plants. Since indirect discharging plants would not be required to meet chlorine limitations and very few indirect discharging plants using priority pollutant-containing biocides and scaling and corrosion inhibitors were identified by the 308 survey, indirect dischargers were not considered separately in the analysis.

Plants Selected for Analysis

The costs of complying with the regulations being proposed by the Agency at this time do not vary by fuel type. Consequently, fuel type was not an important criteria in the selection of model plants for this portion of the analysis. All model plants selected were coal plants because this fuel type accounts for 50 percent of the generating capacity in the steam-electric industry. Only the baseline cost of generating electricity would have differed, however, if nuclear or oil and gas plants had been selected for the plant-level study.

As shown in Table III-1, five plants were selected for the economic impact analysis of the regulations currently being proposed. The existing plants selected for analysis are 10 to 30 years old and have capacity factors of 25 to 60 based on industry averages for those size categories. The two new plants examined have a capacity factor of 60.

Table III-1

MODEL PLANT CHARACTERISTICS

Capacity (MW)	In-Service Year	Capacity Factor
25	1950	25
100	1950	25/50
100	New	60
1000	1970	60
1000	New	60

[1]Capacity factors for plants larger than 100 MW based on industry-wide averages as reported in Electrical World, October 1, 1979, p. 59; for plants smaller than 100 MW based on comparisons of actual generation to available generating capacity.

Determination of Baseline Costs of Generating Electricity

Using the model plant physical and operating characteristics described above, the cost of generating electricity at each model plant was computed. Costs included:

- Capital related charges (depreciation and interest),

- Fuel expenses,
- Non-fuel direct operating and maintenance expenses,
- Indirect expenses (transmission, distribution, and administration expenses), and
- Taxes other than income tax.

Since the majority of existing plants are expected to comply with the proposed regulations in 1984, costs were projected to 1984 in real terms. Capital related charges were annualized on a pretax basis assuming a total plant life of 35 years using the capital recovery method. These charges were then added to annual fuel, operating and maintenance, transmission, distribution, and administration expenses and taxes other than income taxes to obtain a total annual cost of generating electricity. This cost was divided by total plant annual electric power generation based on the plant's capacity and capacity factor to develop a cost on a per kilowatt-hour basis.

New plant baseline costs were developed using a similar methodology. Construction on new plants was assumed to begin in 1980 and the plants were assumed to commence operation in 1987. Table III-2 lists plant-level baseline costs for new and existing plants.

Table III-2

BASELINE COSTS OF GENERATING ELECTRICITY AT MODEL PLANTS SELECTED FOR ANALYSIS

(1980 dollars)

		Cost in Mills per Kilowatt-Hour	
Plant Capacity (MW)	Fuel Type	New Plants	Existing Plants
25	Coal	-	36.7
100	Coal	53.1	33.0
1,000	Coal	44.6	25.0
1,000	Nuclear	39.4	21.8

Analysis of Plant-Level Compliance

Technical compliance costs for the various waste streams were provided by the Agency's technical contractor. Exhibit III-1 lists the capital, operation and maintenance, and total annual costs for the proposed technologies as used in this analysis.

As shown in Table III-3, the costs of compliance with proposed cooling water standards in no case amount to more than 3.5 percent of the cost of generating electricity. This cost would be incurred by a 25 MW plant with a once-through cooling system and instituting a chlorine minimization program as well as dechlorinating. At the opposite end of the spectrum, the largest cost incurred by a 1,000 MW plant would be less than one-tenth of one percent of the baseline cost of generating electricity.

INDUSTRY-LEVEL COSTS

This section extends the plant-level analysis of the effects of compliance with proposed effluent limitations guidelines to the entire electric utility industry. The objectives of the industry-level analysis were (1) to develop an accurate estimate of the total costs to be borne by the electric utility industry and its customers as a result of compliance with the proposed effluent guidelines, and (2) to determine the effects of the increased costs on the physical and financial operations of the utility industry.

Methodology and Assumptions

TBS's approach to assessing the effects of the proposed effluent limitation guidelines on the electric utility industry consisted of the following basic steps:

- Develop baseline projections using TBS's Policy Testing Model (PTm) of the electric utility industry,
- Develop projections incorporating the proposed effluent limitations guidelines, and
- Evaluate changes relative to baseline projections resulting from the additional levels of regulation.

Baseline Projections

The baseline projections are a forecast of electric utility industry financial conditions, assuming a continuation of

Table III-3

INCREMENTAL PLANT LEVEL COSTS OF COMPLIANCE WITH PROPOSED COOLING WATER STANDARDS

(1980 dollars)

Plant Capacity (MW)	New Plants: Mills per Kilowatt-Hour	New Plants: Percent of Baseline	Existing Plants: Mills per Kilowatt-Hour	Existing Plants: Percent of Baseline
Once-Through Cooling Water (chlorine minimization)				
25	N/A	N/A	.405	1.10
100	.032	.077	.05/.10*	.16/.31*
1,000	.003	.007	.003	.01
Once-Through Cooling Water (chlorine minimization and dechlorination)				
25	N/A	N/A	1.27	3.46
100	.137	.26	.18/.42*	.55/1.27*
1,000	.024	.05	.02	.08
Recirculating Cooling Water (dechlorination)				
25	N/A	N/A	.47	1.28
100	.033	.062	.06/.12*	.18/.36*
1,000	.003	.008	.004	.02
Recirculating Cooling Water (use of alternative scaling and corrosion inhibitors)				
25	N/A	N/A	.003	.008
100	.001	.002	.001/.002*	.003/.006*
1,000	.001	.002	.001	.003

N/A = Not applicable.

*Plant with a 25 percent capacity factor.

current regulatory policies but excluding any costs for water pollution control other than the best practicable control technology (BPT) currently available. These projections provide a benchmark for assessing the effects of the proposed effluent limitations guidelines.

The baseline projections rely heavily on the following assumptions:

- Overall growth in peak electricity demand at an average of 3.1 percent per year during the period 1980-2000.
- A changing fuel mix in the industry
  - --Oil and gas capacity declining by 46 percent by 1995 and generation by oil and gas plants declining by 50 percent in the same period as these plants are utilized less intensively.
  - --Nuclear capacity maintaining a significant share of overall generating capacity, rising from 11.2 percent in 1980 to 28.0 percent in 1995.

The baseline does not include the cost of federal air pollution control regulations for new power plants. No water pollution control costs are included in the baseline other than the costs associated with BPT. These expenses have been included in the base capital cost of generation facilities and are not separable.

Projections with Proposed Regulations

To assess the national effects of the proposed effluent limitations guidelines, projections were made incorporating the proposed regulation and suggested treatment technologies while all other assumptions remained unchanged from the base case. This approach was used to allow compilation of the costs either by waste stream or by regulation (BAT, NSPS, or pretreatment).

Results of the National-Level Analysis

The purpose of the national-level analysis is to provide a measure of the electric utility industry's cost of complying with the proposed effluent limitations guidelines. The increases over baseline projections of financial parameters attributable to the proposed effluent limitations guidelines can be used to examine their economic effects. Four financial parameters were selected for this analysis:

- Capital Expenditures--the increase in cumulative capital expenditures for 1980 over the baseline projections of cumulative capital expenditures.

- Annual Revenue Requirements--the increase in the annual revenues required by the industry over baseline revenues to pay for pollution control equipment. This parameter includes revenues required to cover both annual capital charges and operating and maintenance expenses.

- Operation and Maintenance Expenses--the increase over baseline projections of operating costs.

- Average Consumer Charges--the increase in the average cost per kilowatt-hour of electricity, based on sales forecasts and projections of revenue requirements.

Table III-4 lists the industry's baseline for the four financial parameters described above for the years 1985, 1990, and 1995.

Table III-4

BASELINE PROJECTIONS FOR KEY
ELECTRIC UTILITY INDUSTRY FINANCIAL PARAMETERS
(dollar figures in billions of 1980 dollars)

	1985	1990	1995
Cumulative Capital Expenditures from 1980*	$217.88	$444.96	$882.03
Annual Revenue Requirements	128.93	148.09	180.86
Operation and Maintenance Expenses	88.29	99.49	100.63
Average Consumer Charge (mills/KWH)	48.62	46.52	47.89

*Cumulative Capital Expenditures are for 1980-1985, 1986-1990, 1991-1995, and include AFDC.

Costs of Proposed Technologies

Treating cooling water from once-through cooling systems with chlorine minimization and dechlorination will increase capital costs by $70 million through 1985 and $90 million through 1990. The increase in capital costs is no more than 0.03 percent of baseline capital expenditures in any period. Revenue requirements, operating and maintenance expenses, and consumer charges show similar increases, never exceeding four one-hundreths of one percent of baseline figures for these financial parameters (Table III-5).

Table III-5

FINANCIAL EFFECTS OF PROPOSED EFFLUENT LIMITATIONS GUIDELINES FOR ONCE-THROUGH AND RECIRCULATING COOLING WATER

(increase over baseline in 1980 dollars)

	1985	1990	1995
Once-Through Cooling Water (chlorine minimization and dechlorination)			
Cumulative Capital Expenditures			
Millions of Dollars	$ 70	$ 90	$130
Percent of Baseline	.03%	.02%	.01%
Revenue Requirements			
Millions of Dollars	$ 30	$ 40	$ 40
Percent of Baseline	.02%	.03%	.02%
Operation and Maintenance Expense			
Millions of Dollars	$ 20	$ 30	$ 40
Percent of Baseline	.02%	.03%	.04%
Consumer Charge			
Mills per KWH	.01	.01	.01
Percent of Baseline	.02%	.02%	.02%
Recirculating Cooling Water (dechlorination and alternative scaling and corrosion inhibitors)			
Cumulative Capital Expenditures			
Millions of Dollars	$ 50	$ 60	$ 70
Percent of Baseline	.02%	.01%	.01%
Revenue Requirements			
Millions of Dollars	$ 30	$ 30	$ 40
Percent of Baseline	.02%	.02%	.02%
Operation and Maintenance Expense			
Millions of Dollars	$ 20	$ 30	$ 30
Percent of Baseline	.02%	.03%	.03%
Consumer Charge			
Mills per KWH	.01	.01	.01
Percent of Baseline	.02%	.02%	.02%

The costs of treating cooling water from recirculating cooling systems with dechlorination and, where necessary, using scaling and corrosion inhibitors that do not contain the 129 priority pollutants are similar in magnitude to costs for once-through systems. Cumulative capital expenditures increase by $50 million in 1985 and an additional $20 million investment is required through 1995, an increase of 0.02 to 0.01 percent over baseline expenditures. Increases in revenue requirements, operation and maintenance expenses, and consumer charges are similarly low.

Most of the costs of the regulations being proposed at this time would be incurred under BAT regulations. Compliance with the proposed standards by existing direct discharging plants would account for approximately 60 percent of the capital expenditures incurred by the industry through 1995 as a result of the proposed regulations. New plants covered by the proposed NSPS regulations would account for the remaining 40 percent of additional capital expenditures through 1995. The proposed NSPS regulations also include a requirement for dry fly ash handling. However, since the new plant cost of a dry fly ash handling system is equivalent to that of a wet system, there is no incremental cost associated with this NSPS requirement. The proposed pretreatment standards do not include the most costly component of the proposed BAT and NSPS standards--the chlorine limits. Consequently, the only cost incurred by indirect dischargers is the minimal cost of using alternative scaling and corrosion inhibitors.

Cost-Effectiveness of Proposed Technologies

The cost per pound of chlorine removal at plants with recirculating cooling systems is significantly greater than it is at plants with once-through systems. As shown in Table III-6, nationally chlorine minimization at all plants with once-through cooling systems will, in 1985, remove 13 million pounds per year of chlorine at a cost of $.77 per pound. Plants failing to meet the 0.14 mg/l standard and requiring dechlorination in addition to chlorine minimization will remove an additional 4.4 million pounds of chlorine annually at a cost of $4.55 per pound. Plants with recirculating systems, on the other hand, would remove only 34,800 pounds of chlorine at a cost of $862.07 per pound.

The high cost of chlorine removal by dechlorination at plants with recirculating cooling water results not from the cost of the technology but from the low flow volumes of cooling tower blowdown as compared to volumes from once-through cooling systems. Information made available by the Agency's technical

Table III-6

COST-EFFECTIVENESS OF CHLORINE REMOVAL TECHNOLOGIES
(1980 dollars)

	Millions of Pounds of Chlorine Removed (1985)	Cost per Pound of Chlorine Removed
Once-Through Cooling Water		
Chlorine Minimization	13.0	$ 0.77
Dechlorination	4.4	4.55
Recirculating Cooling Water		
Dechlorination	.03	862.07

contractor indicates that flow volumes for cooling tower blowdown can be 100 to 300 times smaller than once-through cooling water flows for plants with equivalent capacity. Chlorine concentrations are only slightly higher for plants with recirculating systems. Consequently, although revenue requirements for the three technologies are of the same magnitude, the smaller quantities of chlorine removed at plants with recirculating systems result in much higher costs per pound of chlorine removed at these plants.

Under the proposed regulations, zinc and chromium would be eliminated from recirculating cooling water waste streams through the use of scaling and corrosion inhibitors not containing these priority pollutants. The cost of eliminating zinc (73,000 pounds per year) is approximately $11 per pound and that of eliminating chromium (17,000 pounds per year) is $53 per pound. In addition 67,000 pounds of chlorinated phenols would be eliminated by the use of biocides not containing the 129 priority pollutants. Since alternatives to these biocides exist at approximately the same cost, there is no cost associated with their use.

CONCLUSIONS

The regulations currently being proposed would not significantly affect the electric utility industry. None of the key industry financial parameters examined increases by more than one-tenth of one percent as a result of industry compliance with the regulations and both the cost of generating electricity and average consumer charges increase by one twenty-fifth of one percent.

Individual utilities and the industry as a whole should not experience significant difficulties raising sufficient capital to comply with the regulations. The maximum capital expenditure potentially incurred by any single plant is $165,700 spent by a 1,000 MW plant requiring both chlorine minimization and dechlorination. This figure compares to a $300 to $500 million investment required for a recently completed 1,000 MW plant. Nationally, while the $150 million industry capital expenditures in the period 1980-1990 is not an insignificant sum of money, it is dwarfed by industry baseline capital expenditures of $445 billion.

At the plant level the only plants that incur significant increases in the cost of generating electricity are very small, old plants used to provide power during periods of peak demand. Since these plants generate only a very limited portion of an individual utility's total electrical output, cost increases incurred by them would not translate into equivalent increases in consumer charges.

The only cost of the proposed regulations that appears significant is the cost of chlorine removal at plants with recirculating cooling systems. These plants incur one-half of the annual national cost of chlorine removal, yet they account for only 0.2 percent of the chlorine removed nationally. The regulations requiring dechlorination at plants with recirculating cooling systems are not economically burdensome; however, their cost-effectiveness is much lower than that of regulations with once-through cooling.

At this time the Agency is gathering more information concerning ash transport waters. Control of these streams is significantly more expensive than it is for cooling water streams. For example, cumulative capital expenditures for dry fly ash handling by existing plants would amount to $2.8 to $3.5 billion (depending on the plant capacity cutoff selected) as compared to $200 million for cooling water. The costs for dry fly ash handling are examined in greater detail in TBS's April 1980 <u>Draft Economic Analysis for the Revision of the Steam-Electric Utility Industry Effluent Limitations Guidelines.</u>

Exhibit III-1

COST OF TECHNOLOGIES FOR PROPOSED REGULATIONS[1]

(1980 dollars)

	Once-Through Cooling Water					
	Chlorine Minimization			Chlorine Minimization and Dechlorination		
Plant Size (Mw)	Annual Operation and Maintenance Cost per Kilowatt	Capital Cost per Kilowatt	Total Annual Cost per Kilowatt	Annual Operation and Maintenance Cost per Kilowatt	Capital Cost per Kilowatt	Total Annual Cost per Kilowatt
25	$.37	$1.45	$.89	$.80	$4.52	$2.81
100	.09	.37	.23	.36	1.29	.92
1,000	.01	.04	.02	.08	.17	.13

	Recirculating Cooling Water					
	Dechlorination			Alternative Scaling and Corrosion Inhibitors		
Plant Size (Mw)	Annual Operation and Maintenance Cost per Kilowatt	Capital Cost per Kilowatt	Total Annual Cost per Kilowatt	Annual Operation and Maintenance Cost per Kilowatt	Capital Cost per Kilowatt	Total Annual Cost per Kilowatt
25	$.24	$2.45	$1.03	$.07	$0	$.07
100	.06	.61	.26	.05	0	.05
1,000	.01	.06	.02	.04	0	.04

[1]Total annual costs include annualized capital costs for existing plants and annual operation and maintenance costs.

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